Technical University of Crete

School of Mineral Resources Engineering

MSc Thesis

Sensitivity Analysis of the PVT data Accuracy to Well Performance

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Abstract

Nowadays, computer simulation is the main tool of reservoir and/or production engineers to optimize production. For this task, a Pressure – Volume - Temperature (PVT) analysis must be conducted, a process that is not always feasible at early production stages. This is where black oil correlations come as the most viable solution to overcome the aforementioned obstacle.

Numerous empirical formulae are available in all reservoir and well modeling software, whose utilization results to the prediction of PVT properties of a reservoir fluid. However there are two crucial questions regarding the use of black oil correlations that need to be answered. The main one is whether they are all characterized by the same accuracy in their predictions or not. In this sense, what must be done to assess their credibility is another thing that needs to be answered.

Based on that, this thesis evaluates the prediction performance of the most well - known black oil correlations, against PVT measurements for different types of oil, before and after they were tuned against the available field data. These simulations were run using PROSPER, an industrial production and system analysis software.

The results taken show that even for the simplest fluid, the utilized correlation should be selected properly, while the matching process on field PVT data is always recommended.

Chapter 1

Introduction

1.1 Introduction

Crude oil is a fuel source of vital importance to society and covers more than one – third of the world's energy needs. Besides the industrial use of oil and its derivatives, another fact that enhances their importance is the widespread use in our everyday lives – from fueling airplanes and cars, to manufacturing electrical devices, as well as the development of chemical products such as medicines, plastics or lubricants.

This ever-growing demand for oil, has led not only to larger quantities being produced, but has also resulted in the invincible need for production optimization and increased exploitation efficiency of the global reserves. Production optimization is feasible through the utilization of technology and experience acquired by the oilfield engineers over the years.

More specifically, the main scope of a reservoir and/or a production engineer is to maximize the hydrocarbon recovery, in the most energy, time and cost – efficient way possible. In order for that to happen, the main tool engineers use is computer simulation of what takes place in the reservoir, through the tubing and at surface during production. In turn, this is achieved through the analysis of the volumetric and phase behavior of the produced hydrocarbons, as they move upwards from the reservoir to the surface, which is briefly named as PVT analysis.

During oil production, and as pressure and temperature shift, hydrocarbons' composition, as well as density, viscosity and compressibility, also change. Pressure-Volume Temperature (PVT) analysis is the study of the changes in volume of a fluid, as a function of pressure and temperature. PVT analysis provides extremely vital information regarding the physical and thermodynamic behavior of the reservoir fluids, leading to the effective management of the production while the reservoir system is being depleted. Practically, PVT data is utilized from the beginning of the field's development until the very last day of the production. Thus, a thorough understanding of the reservoir fluid's PVT properties is the ideal basis to proceed in the reservoir simulation and consequently in the production optimization.

A good understanding of the physical properties of the flowing fluid is of outmost importance for the analysis and classification of reservoir fluids. More specifically, the estimation of the bubble point pressure, gas solubility, oil formation volume factor at bubble point, as well as compressibility, plays a vital role in the material balance equation. In addition, for carrying out interpretation of production tests, viscosity also plays an important role.

The ideal samples used for the PVT lab measurements are the ones collected bottom – hole, since a successful PVT analysis requires that the samples represent the original hydrocarbon composition in the reservoir. Surface samples can also be used, due to their availability and ease in obtaining, but again bottom – hole ones are always preferred.

Nevertheless, having a thorough and valid PVT analysis is not always feasible due to several reasons. These include:

- A PVT analysis takes considerable time to be processed, while in case of a remote field – stranded onshore in the middle of a desert or an offshore one far away from the shore - the transportation of the samples can result even in a delay of several months.
- There are only a few authorized PVT laboratories in the world having enormous workload, resulting in great time periods of waiting until all the samples are examined.
- The cost of the sampling procedure, along with the analysis is too great.
- Sometimes the samples are not reliable, so the analysis is not feasible.

1.2 Importance of Black Oil Correlations Use in Reservoir/Well Flow Simulation

Under the aforementioned circumstances when crucial reservoir engineering decisions have to be made on site, the utilization of empirical correlations that relate easily obtained reservoir properties to parameters, such as P_b and B_o, is the only viable option for the prediction of the PVT properties. Correlations are also useful, in case:

- The experimental data don't constitute a full report
- Only field measurements are available
- As a tuning tool against laboratory results
- When making estimations for experimental design

Furthermore, during a reservoir's flow simulation in any wellbore managing software – either in an academic or an industrial scale - PVT data in various pressure and temperature points are required. However, in case the experimental data are of a limited extent these empirical formulae make not only the simulation, but also the tuning of the production feasible.

This approach in reservoir simulation is referred to as the Black – oil model. It is the simplest way to generate the PVT properties at any pressure and temperature during a reservoir's depletion, having field PVT data of a limited extent. Gas and oil properties in a black oil model depend only on pressure. This approach is based on a simple recombination of the reservoir fluid's PVT properties from surface to reservoir conditions. Black oil correlations treat the oil as it is composed of two phases, the stock tank oil and the dry gas collected at standard conditions. There are lots of correlations utilized for the estimation of the properties of a typical black oil reservoir, the most applicable of which we will see below in the Literature Review.

Black oil model approach is the most time – efficient way for a reservoir/production engineer to simulate the phase behavior of the fluid. Nevertheless, in case of complex multi – component systems the fluid phases have to be treated as n_c component mixtures, leading to the necessity of a compositional simulation.

More specifically, nowadays compositional models are used only when modeling of complex phase and flow behaviors, such as miscible-gas injection, depletion of volatile-oil/gascondensate reservoirs, high CO_2 concentration are concerned. The main tools used in this are Equations of State (EoS). They are used due to their capability in determining the composition of all hydrocarbon phases during a reservoir's depletion. Equations of State are relationships describing relationships of pressure, volume, and temperature (PVT) for each of the pure components. In order to obtain an accurate result by means of this model, reliable thermodynamic properties for all necessary components are required in advance.

Through such relationships an accurate description of the volumetric and phase behavior of pure compounds and mixtures is performed with consistency. Although it is a very accurate way of prediction, the number of data needed makes black oil approach the first choice in case its use is applicable. Yet, in case of complex multi – component systems its use is inevitable.

1.3 Thesis scope

The development stage of any oil field takes place after the appraisal period has been completed successfully and before the field's production begins in full scale. At this stage and due to the lack of PVT studies, different black oil correlations may serve as a solution for the prediction of PVT properties of a reservoir fluid. The data predicted by empirical formulae may serve as parameters in volumetric calculations of reserves, estimated oil production rate and related calculations. Thus, choosing an accurate correlation at this stage can be easily considered to be the most crucial condition during the modeling of the fluid's flow in a well.

In addition, reservoir simulation results show that the black-oil model can be used for almost every depletion case, if the black-oil PVT data are generated properly. But how a black oil model is generated properly? The answer lies in the selection of the most accurate and valuable correlation for the specific oil type. Based on that, this thesis investigates the prediction accuracy of the most well-known PVT correlations present in the literature (e.g Standing, Al – Marhoun) against PVT measurements for different types of oil (Low and Medium API).

To do so, the first question that had to be answered was whether the black oil correlations applied in PROSPER result to similar enough predictions of the fluid properties, or not. This was accomplished by evaluating the range of the non – tuned PVT properties, calculated through the software when different empirical formulae were utilized. Additionally, these correlations were tuned against field PVT data, in order to examine if the aforementioned variation is decreased through the matching process.

When correlations result in the same prediction of fluid properties even before tuning, consequently that gives to the users the ability of selecting freely any of the applicable formulae to proceed with their work. However, if the differences in the calculations are vast, a thorough examination of the correlations, as well as their tuning, is required to ensure the validity in the predictions that are going to be followed.

Several criteria consisted the base of this evaluation, the most crucial of which was the deviation of the correlations from the experimental data, during the tuning process. That is because, as it is going to be clarified in the following contents of this text, the lower the deviation of a correlation is, the more the originality of it is conserved, leading to more valid results.

1.4 Thesis Contents

The primary task in this thesis is to evaluate and compare the prediction accuracy of the most well – known black oil correlations, against PVT data of different types of oil. The text in question is been sectioned as following:

- **Chapter 1** involves what already has been presented in the previous pages
- **Chapter 2** is a description of all correlations that have been implemented in most of well modeling software packages
- **Chapter 3** is an analysis on how a well is modeled in PROSPER. The data introduced to the software is presented, as well as the way the necessary calculations were performed.
- Moving on, in **Chapter 4** the fluid data basis of this thesis is given. The evaluation regarding the variations of PVT calculations for the different correlations is also presented, with and without tuning them. Under the same perspective, the predictions of flow rates and the saturation conditions depth differences exhibited are also presented.
- **Chapter 5** includes the conclusions made through the aforementioned study

Chapter 2

Correlations Review

2.1 Correlations Review [1],[2]

The history of reservoir fluid properties correlations in the petroleum industry has started more than 60 years ago. Multiple empirical equations have been proposed over the years, for the calculation of fundamental reservoir fluid properties. Thus, in order to be able to understand the differences between various correlations in use, a brief analysis of them is required. In this chapter, a review of the examined ones in this thesis is going to take place. More specifically, the correlations of interest are the ones referring to the prediction of the following PVT properties:

1. Solution gas – oil ratio – GOR
2. Bubble point pressure – P_b
3. Oil formation volume factor – FVF
4. Oil viscosity

2.1.1 Solution Gas Oil Ratio [1], [2],[10]

The gas solubility, R_s, is defined as the number of standard cubic feet of gas that dissolve in one stock-tank barrel of crude oil at certain pressure and temperature. The solubility of a natural gas is a strong function of: pressure, temperature, API gravity and gas gravity. In general, rather than measuring the amount of gas that dissolves in a given SC crude oil as the pressure is increased, for convenience reasons (due to the fact that during the reservoir's depletion the pressure is decreased), it is preferred to determine the amount of gas that comes out of solution as the pressure decreases .

A typical gas solubility curve, as a function of pressure for an under saturated crude oil, is shown in Figure 1. As the pressure is reduced from the initial p_i reservoir pressure, to the bubble point one (p_b), no gas evolves from the oil, thus the gas solubility remains constant at its maximum value of R_{sb}. Below the bubble point pressure, the solution gas is liberated and the value of R_s decreases with pressure.

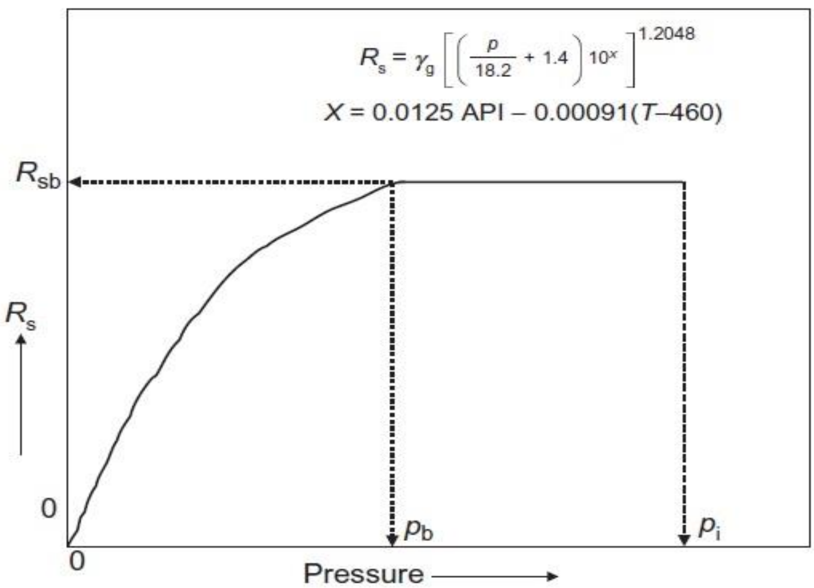


Figure 1 Typical Gas Solubility – Pressure relationship

Empirical Correlations for Gas Solubility

In case the experimentally gas solubility of a crude oil system has not been measured, its determination from empirically derived correlations is needed. These five empirical correlations are:

- Standing's correlation
- Vasquez-Beggs's correlation
- Glaso's correlation
- Marhoun's correlation
- Petrosky-Farshad's correlation

Standing's Correlation

Standing (1947) proposed a graphical correlation for determining the gas solubility as a function of:

- Pressure
- System temperature
- Gas specific gravity and
- API gravity

This correlation, having an average error of 4.8%, is valid for applications at and below bubble point pressure of the crude oil. The formula in question was developed through a total of 105 experimentally determined data points on 22 hydrocarbon mixtures from California crude oils and natural gases.

The mathematical formula Standing proposed (1981) to express the aforementioned graphical correlation, has the following form:

$$R_s = \gamma_g \left[\left(\frac{p}{18.2} + 1.4 \right) 10^x \right]^{1.2048} \quad \textbf{(1)}$$

with x = 0.0125API – 0.00091 (T-460)

where

R_s = gas solubility, scf/STB
T = temperature, °R
P = system pressure, psia
γ_g = solution gas specific gravity
API = oil gravity, °API

Vasquez – Begg's Correlation

Vasquez and Beggs (1980) proposed an improved empirical correlation (Equation 2) for the estimation of R_s, in which the coefficients c_1, c_2, c_3 are indicated by the oil gravity. The correlation was obtained by a regression analysis of 5008 measured gas solubility data points that were divided into two groups, based on their oil gravity. Once evaluated (Sutton and Farshad – 1984), this empirical formula is characterized by an average absolute error of 12.7%. The aforementioned equation has the following form:

$$R_s = C_1 \gamma_{gs} p^{C_2} \exp\left[C_3\left(\frac{\text{API}}{T}\right)\right]$$

(2)

Where,

R_s = gas solubility, scf/STB
T = temperature, °R
P = system pressure, psia
γ_{gs} = gas gravity at the reference separator pressure
API = oil gravity, °API

The applicable values for the coefficients are:

Coefficients	API ≤ 30	API ≥ 30
C_1	0.362	0.0178
C_2	1.0937	1.1870
C_3	25.7240	23.931

Due to the fact that the value of the specific gravity of the gas depends on the separation conditions of it from the oil, its value used in the above equation was obtained having a separator pressure of 100 psig; which is representative of the average field separator conditions. Vasquez and Beggs proposed the following relationship for adjusting the gas gravity to the reference separator pressure:

$$\gamma_{gs} = \gamma_g\left[1 + 5.912(10^{-5})(\text{API})(T_{sep} - 460)\log\left(\frac{p_{sep}}{114.7}\right)\right]$$

(3)

where

γ_g = gas gravity at the actual separator conditions of P_{sep} and T_{sep}
P_{sep} = actual separator pressure, psia
T_{sep} = actual separator temperature, °R

The gas gravity used to develop all the correlations reported by the authors was that which would result from a two-stage separation. The first-stage pressure was chosen as 100 psig and the second stage was the stock-tank. If the separator conditions are unknown, the unadjusted gas gravity may be used in Eq. 2.

Glaso's correlation

Glaso (1980) introduced a correlation for estimating the gas solubility again as a function of pressure, temperature, gas specific gravity and API gravity. The average error reported was equal to 1.28%, along with a standard deviation of 6.98%. This formula was developed from studying 45 North Sea crude oil samples, and it has the following form:

$$R_s = \gamma_g \left\{ \left[\frac{\text{API}^{0.989}}{(T-460)^{0.172}} \right] (A) \right\}^{1.2255} \quad \textbf{(4)}$$

where

R_s = gas solubility, scf/STB
T = temperature, °R
API = oil gravity, °API

Parameter A is a pressure – dependent coefficient defined as:

$A = 10^X$
and the X exponent is equal to:

$$X = 2.8869 - [14.1811 - 3.3093 \log(p)]^{0.5}$$

Where

p = system pressure, psia

Marhoun's correlation

Marhoun's formula (1988) was developed to estimate the saturation pressure of the Middle Eastern crude oil systems, by using 160 experimental saturation pressure data. The equation was rearranged and solved for the gas solubility having the following form:

$$R_s = \left[a \gamma_g^b \gamma_o^c T^d p \right]^e \quad \textbf{(5)}$$

where

γ_g = gas specific gravity
γ_o = stock – tank oil gravity

a–e = coefficients of the above equation with the following values

a = 185.843208
b = 1.877840
c = 3.1437
d = 1.32657
e = 1.39844

Petrosky-Farshad's Correlation

In Petrosky – Farshad's case (1993), a non - linear multiple regression software was used to develop the correlation. A PVT database was created through 81 laboratory analyses from the Gulf of Mexico crude oil system. The proposed equation is the following:

$$R_s = \left[\left(\frac{p}{112.727} + 12.340\right)\gamma_g^{0.8439}10^x\right]^{1.73184} \tag{6}$$

where χ is

$$x = 7.916(10^{-4})(\mathrm{API})^{1.5410} - 4.561(10^{-5})(T-460)^{1.3911}$$

Where,

R_s = gas solubility, scf/STB
T = temperature, °R
P = system pressure, psia
γ_g = solution gas specific gravity
API = oil gravity, °API

☆ Petrosky-Farshad's Correlation was not examined in this thesis.

2.1.2 Bubble point Pressure [1],[2], [9], [10]

Bubble point pressure, or saturation pressure, is the one at which the first bubble of gas evolves out of solution. The empirical correlations used for this property, are a function of the gas solubility, system temperature, as well as oil (API) and gas (γ_g) gravity.

Empirical Correlations for Bubble Point Pressure

Standing's Correlation

Standing developed (1947) a graphical correlation, based on data from a narrow geographical location with no corrections for oil type or non - hydrocarbon contents. That is why this formula must be used with caution in case of non – hydrocarbon components being present in the system. The proposal was made based on 105 experimental data points from a series of 22 different crude oil and natural gas mixtures of the Californian oil fields. The graph for the bubble point pressure calculation is shown in Figure 2, and the mathematical formula used is the following one (7). Standing reported an average relative error of 4.8%.

$$p_b = 18.2\left[(R_s/\gamma_g)^{0.83}(10)^a - 1.4\right] \tag{7}$$

where α is estimated as

$$a = 0.00091(T-460) - 0.0125(\mathrm{API})$$

and

R_s = gas solubility, scf/STB

P_b = bubble point pressure, psia

T = system temperature, °R

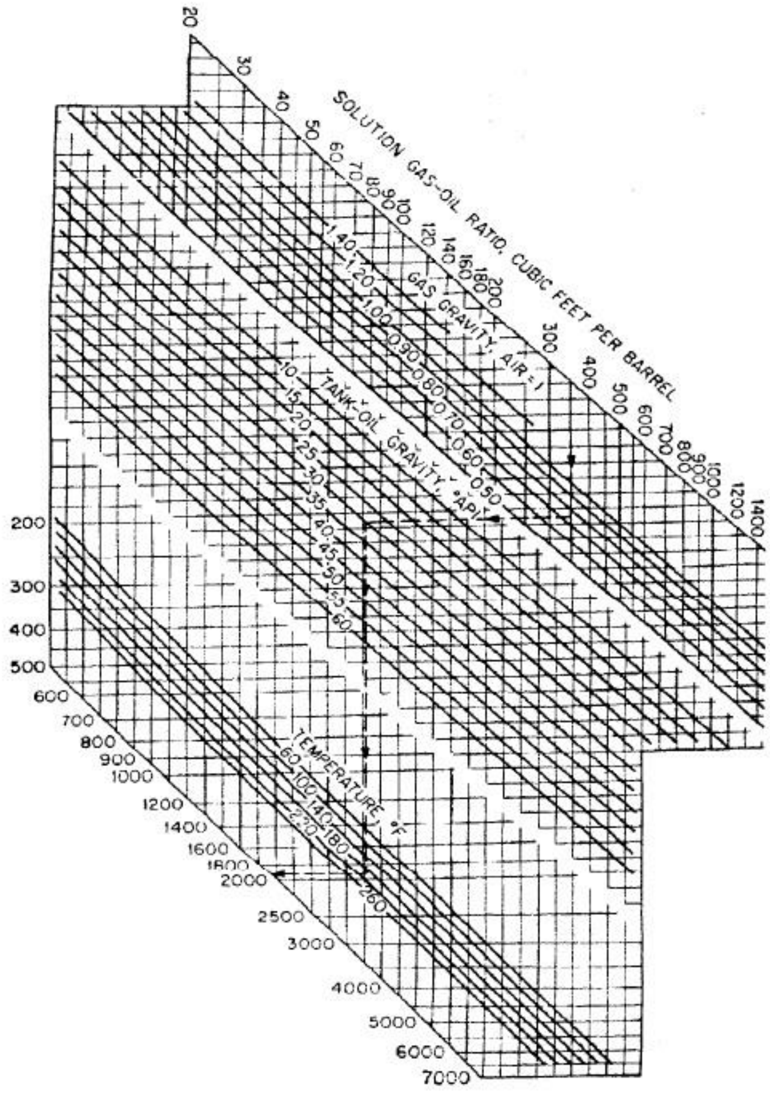


Figure 2 Standing's chart for the calculation of P_b

Vasquez and Beggs's Correlation

Vasquez and Beggs developed this formula by solving their gas solubility correlation (eq.2) for the bubble point pressure. More specifically:

$$p_b = \left[\left(C_1 \frac{R_s}{\gamma_{gs}} \right) (10)^a \right]^{C_2} \tag{8}$$

Where exponent α is estimated by

$$a = C_3\left(\frac{\text{API}}{T}\right)$$

And the c_1, c_2 and c_3 coefficients get the following values:

Coefficients	API ≤ 30	API ≥ 30
C_1	27.624	56.18
C_2	10.914328	0.84246
C_3	-11.172	-10.393

Glaso's Correlation

Glaso (1980) proposed a correlation for the estimation of bubble point pressure, which reported an average absolute percent of relative error equal to 1.28% under a pressure range of 150 to 7000 psig, and 0.7% when the pressure range is from 2000 to 7000 psig. The experimental data used were 45 oil samples from the North Sea's hydrocarbon system. The mathematical formula of the correlation is the following:

$$\log(p_b) = 1.7669 + 1.7447\log(A) - 0.30218[\log(A)]^2 \quad \textbf{(9)}$$

With the parameter A being estimated by

$$A = \left(\frac{R_s}{\gamma_g}\right)^{0.816}\frac{(T-460)^{0.1302}}{(\text{API})^{0.989}}$$

Al – Marhoun's Correlation

Al – Marhoun developed (1988) an empirical formula for the determination of saturation pressure, using 160 experimental points from PVT data of 69 bottom - hole fluid samples, taken from 69 oil reservoirs of the Middle East. The proposed correlation has an average relative and absolute relative error of 0.03% and 3.66%, respectively and it has the following form:

$$p_b = aR_s^b\gamma_g^c\gamma_o^dT^e \quad \textbf{(10)}$$

Petrosky and Farshad's Correlation

Petrosky and Farshad (1993), by solving their equation for gas solubility (eq.6), developed a bubble point pressure correlation for the crude oils of Gulf of Mexico, by using 81 laboratory PVT analyses from more than 32 reservoirs located offshore Texas and Louisiana. The equation in question is of the following form:

$$p_b = \left[\frac{112.727 R_s^{0.577421}}{\gamma_g^{0.8439}(10)^x}\right] - 1391.051 \quad (11)$$

where the correlating parameter χ has already been defined, along with the R_s's equation.

The reported errors of this correlation are an average relative and an absolute one equal to -0.17% and 3.28%, respectively. Petrosky-Farshad's Correlation was not examined in this thesis.

2.1.3 Oil Formation Volume Factor [1], [2]

The oil FVF, or B_o, is defined as the ratio of the oil volume along with the gas in solution, at the reservoir temperature and pressure, divided to the oil volume at standard conditions. Thus, it is obvious that FVF is always equal or greater than unity. Its mathematical formula is:

$$B_o = \frac{(V_o)_{p,T}}{(V_o)_{sc}} \quad (12)$$

Where

B_o = oil FVF, bbl/STB

$(V_o)_{p,T}$ = volume of oil, in bbl, under reservoir pressure and temperature

$(V_o)_{sc}$ = volume of oil is measured under SC, STB

As it seen in Figure 3, in an under saturated reservoir and as the pressure is reduced below the initial reservoir pressure, the oil volume increases due to the oil expansion, resulting also in the increase of the oil FVF. This behavior of the oil FVF continues until saturation pressure is reached, under which oil reaches its maximum volume and consequently the maximum value of the FVF is also reached. As the pressure is reduced below bubble point, both the oil's volume and B_o are decreased, due to the gas liberation. As atmospheric conditions are reached, the value of B_o is equal to unity.

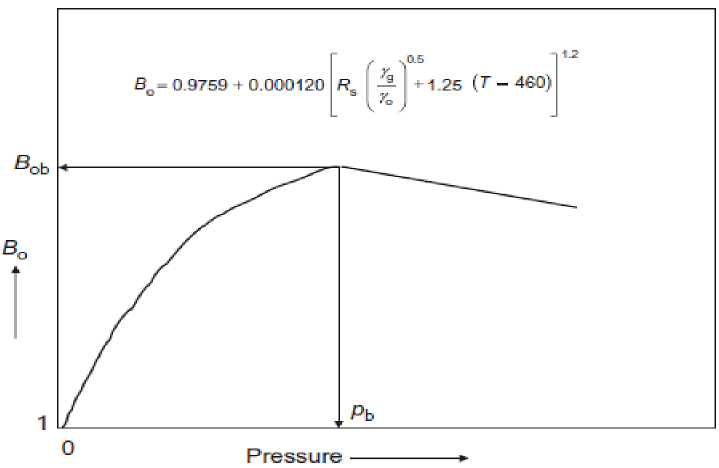


Figure 3 Typical B_o – pressure curve

The most widely used empirical correlations for the prediction of the oil formation volume factor are:

- Standing's correlation
- Glaso's correlation
- Marhoun's correlation
- Vasquez and Beggs's correlation
- Petrosky and Farshad's correlation
- The material balance equation

In this thesis, the correlations examined for the estimation of B_o are the first 4.

Empirical Correlations for Oil Formation Volume Factor

Standing's Correlation

Standing (1947) developed a graphical correlation reporting an average error of 1.2%, having as parameters the gas solubility, gas and oil gravity and temperature. It was originated from utilizing 105 experimental data points of 22 Californian hydrocarbon systems. At 1981, Standing proposed a more easy to handle mathematical form which lies below.

$$B_o = 0.9759 + 0.000120\left[R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25(T-460)\right]^{1.2} \tag{13}$$

Glaso's Correlation

Glaso (1980) originated the following correlations by using PVT data of 45 oil samples. The average error reported was -0.43%, along with a standard deviation of 2.18%. The mathematical formulae are the following:

$$B_o = 1.0 + 10^A \tag{14}$$

where parameter A being

$$A = -6.58511 + 2.91329 \log B^*_{ob} - 0.27683\left(\log B^*_{ob}\right)^2 \tag{15}$$

And B_{ob} being defined as

$$B^*_{ob} = R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.526} + 0.968(T-460) \tag{16}$$

Al – Marhoun's Correlation

Marhoun (1988) developed an empirical correlation by using a nonlinear multiple regression analysis on 160 experimental data points, obtained from 69 oil reserves of the Middle East. The proposed expressions are the following:

$$B_o = 0.497069 + 0.000862963T + 0.00182594F + 0.00000318099F^2 \tag{17}$$

With F being estimated as

$$F = R_s^a \gamma_g^b \gamma_o^c \tag{18}$$

And the coefficients a,b and c having the following values:

a = 0.74239

b = 0.323294

c = -1.20204

Vasquez and Begg's Correlation

Vasquez and Beggs (1980) developed a general relationship for the estimation of oil FVF, characterized by an average error of 4.7%. The research was made through the regression analysis technique, based on 6000 data points from various fields all over the world. The formula proposed is:

$$B_o = 1.0 + C_1 R_s + (T - 520)\left(\frac{\mathrm{API}}{\gamma_{gs}}\right)[C_2 + C_3 R_s] \tag{19}$$

Where γ_{gs} is defined by the equation

$$\gamma_{gs} = \gamma_g \left[1 + 5.912(10^{-5})(\mathrm{API})(T_{sep} - 460)\log\left(\frac{p_{sep}}{114.7}\right)\right]$$

And the coefficients c_1, c_2, c_3 get the values:

Coefficients	API ≤ 30	API ≥ 30
C_1	$4.677*10^{-4}$	$4.67*10^{-4}$
C_2	$1.751*10^{-5}$	$1.1*10^{-5}$
C_3	$-1.811*10^{-8}$	$1.337*10^{-9}$

2.1.4 Oil Viscosity [1], [7], [8]

Crude oil viscosity is an important physical property that controls the flow of oil through porous media and pipes. Absolute viscosity provides a measurement of a fluid's internal resistance to flow. Correlations for the calculation of viscosity can be expected to evaluate viscosity for temperatures ranging from 35 to 300°F.

The principal factors affecting viscosity are:

- Oil composition

- Temperature
- Pressure
- Oil and gas gravity
- Gas solubility

Depending on the pressure, p, the viscosity of crude oils can be classified into three categories:

- Dead oil viscosity, μ_{od} - The dead oil viscosity (oil with no gas in the solution) is defined as the viscosity of crude oil at atmospheric pressure and system temperature, T.
- Saturated oil viscosity, μ_{ob} - The saturated (bubble point) oil viscosity is defined as the viscosity of the crude oil at any pressure less than or equal to the bubble point pressure.
- Under saturated oil viscosity, μ_o - The under saturated oil viscosity is defined as the viscosity of the crude oil at a pressure above the bubble point and reservoir temperature.

A brief analysis of the correlations utilized for the prediction of oil viscosity is followed. All of the existing formulae are going to be mentioned, but only the ones examined in this thesis will be further analyzed. These are the Beggs – Robinson and the Beal ones.

Dead Oil Correlations

Several empirical equations are proposed for the estimation of viscosity of the dead oil, which are based on the API gravity of the oil and the system temperature. These correlations are listed below:

- Beal's correlation
- Beggs – Robinson's correlation
- Glaso's correlation

Since the experimental data used in this analysis are for under saturated and/or saturated conditions, the aforementioned correlations are not going to be analyzed for dead oil conditions.

Saturated oil correlations

Viscosity of crude oil decreases as pressure decreases from reservoir to saturation conditions. There are three empirical methods in use for the estimation of viscosity of saturated oil:

- Beggs-Robinson correlation

Beggs and Robinson (1975) proposed an empirical equation to estimate the oil's viscosity at or below bubble point conditions. Its form is:

$$\mu_{ob} = a(\mu_{od})^b \quad (20)$$

where

$\alpha = 10.715(R_s+100)^{-0.515}$

$b = 5.44(R_s+150)^{-0.338}$

The development of this correlation was done by using 2073 saturated oil viscosity measurements, and it reported an accuracy of -1.83% with a standard deviation of 27.25%.

- Chew-Connally correlation
- Abu-Khamsin and Al-Marhoun

Under saturated oil Correlations

In order to calculate oil viscosity at pressures above bubble point, it is needed to firstly estimate it at its P_b, and then adjust it to higher pressures. The three applicable correlations for this are:

- Beal's correlation

Based on 52 experimental data points, Beal (1946) proposed a graphical correlation, for which an average error of 2.7% was reported. This curve of the under saturated μ_o versus pressure, was later fitted by Standing (1981).

The proposed expression is:

$$\mu_o = \mu_{ob} + 0.001(p - p_b)\left[0.024\mu_{ob}^{1.6} + 0.038\mu_{ob}^{0.56}\right] \quad (21)$$

where μ_o is the under saturated oil viscosity at a pressure p, while μ_{ob} is the oil viscosity at bubble point pressure.

- Khan's correlation
- Vasquez-Beggs correlation

2.1.5 Isothermal compressibility coefficient of crude oil 'c_o' [1], [2]

Isothermal compressibility coefficients, are a requirement for the solution of many reservoir engineering problems, as well as in the determination of the physical properties of the under saturated crude oil.

It is defined as the rate of change in volume with respect to pressure increase per unit volume, while all variables besides pressure are constant, including temperature. The mathematical definition of the 'c' of a substance is:

$$c_o = -\frac{1}{V}\left(\frac{\partial V}{\partial p}\right)_T \tag{22}$$

For an oil system, the isothermal compressibility coefficient of the oil, c_o, is grouped into two categories, based on the prevailing reservoir pressure:

i. Under saturated 'c_o' – the crude oil exists as a single phase fluid and all the gas is still dissolved in solution. Here, the compressibility coefficient is equivalent to the changes of volume that are associated with the oil expansion/compression of the monophasic oil, along with the changes in reservoir pressure.
ii. Saturated 'c_o' – as it has already been mentioned before, after the bubble point pressure has been reached and as the pressure continues to decrease, the dissolved gas evolves out of solution, leading to differences in the gas solubility. This also results in changes of the oil volume, and consequently to a different c_o.

PROSPER's software, although in saturated systems ($p<p_b$) handles all the calculations based on the correlation selected by the user, in the monophasic region of a reservoir it functions according to the compressibility's correlation selected by the software itself. There are several correlations for the estimation of both the under saturated, and the saturated oil compressibility. These are:

Under saturated Isothermal compressibility coefficient's Correlations [5], [6], [7]

- Trube's
- Vasquez – Beggs
- Petrosky – Farshad

In PROSPER, when using the black oil approach to simulate the reservoir flow, compressibility of water is calculated through the calculation of water FVF. More specifically, water compressibility is a function of:

- Salinity
- Temperature
- Volume with respect to pressure

Thus, by specifying water salinity (B_w) and the possible impurities contained in the solution, the black oil correlations can now generate the PVT properties of the fluid, in which water FVF is also estimated. Then, from the B_w the water c_w can be now calculated through the following equation:

$$(c_w)_P = \left(\frac{-1}{Bw}\right)_P * \left(\frac{dBw}{dP}\right) \tag{23}$$

The formulae used for the estimation of water FVF are the ones mentioned in the papers:

i. Craft and Hawkins (1959) , page 131, Petroleum Reservoir Engineering
ii. Numbere, Brigham and Standing (Nov 1977), page 16, physical properties of petroleum reservoir brines, Petroleum Institute of Stanford University

Chapter 3

Model Setup in PROSPER

3.1 About PROSPER [7]

PROSPER is the industry's standard well and pipeline modeling software, utilized by major operators worldwide. It is a part of the Integrated Production Modeling Toolkit (IPM). PROSPER is a single and multilateral well performance program enabling the design of consistent and reliable well models. All aspects of well bore modeling can be addressed through its use, from the fluid characterization to the reservoir's inflow and outflow performance.

Production prediction is another task that can be performed with the aid of this software, since running of production profiles for well and/or reservoir systems is an action easily performed through it. Additionally, engineers utilize PROSPER for modeling evaluation and calibration. The aforementioned is accomplished by tuning measured field data introduced to the system with different parts of the model. Furthermore, to ensure the validity of the calibration, quality control is also a feature of the software.

All design and optimization simulations of this study were performed using the PROSPER software.

3.2 Available PVT data

The available PVT data has been obtained from a direct flash of the reservoir fluid, from reservoir up to standard conditions. According to its API gravity, it is considered an oil of medium volatility and at the initial reservoir conditions it is a monophasic one, since the initial reservoir pressure is higher than the bubble point one. Have in mind that the aforementioned PVT data, also shown in Table 1, are indeed used in some runs of this thesis. However, here they only serve as an example of fluid properties.

Table 1 Available laboratory PVT measured data

Property	Units	Value
GOR	m^3/m^3	115
API	API	29
S_g		0,88
P_i	psi	6513
T_{res}	◦F	171
P_b	psi	2293
$Bo_{@Pb}$		1,32
$\mu o_{@Pb}$	cP	1,16
$Bo_{@Pi}$		1,27
$\mu o_{@Pi}$	cP	1,46
Water salinity	ppm	15000

3.3 How a model is set up in PROSPER

Regardless the final scope of the project that is going to take place in PROSPER, the modeling of it starts by introducing the basic information about the examined well, an action that is done in the options summary section. Moving on, it is mandatory to introduce the PVT data in the respective section, so that the system will be able to predict pressure and temperature changes during reservoir fluid's flow.

After that, the well's hardware, deviation survey and temperature profile are introduced to the system. Next step is the definition of the inflow from the reservoir into the bottom of the well, in the IPR section. There, based on the reservoir model selected and the general reservoir properties introduced to the system, the IPR curve for the current reservoir pressure is generated, or in other words a relationship between the bottom - hole pressure (BHP) and the liquid flow rate passing into the well is developed.

Finally, after all necessary well data has been introduced, the user is able to proceed with the desirable actions, such as flowrate calculations, the examination of future production scenaria, production optimization, etc.

Below, a more analytical explanation of the procedure followed during the setting up of the model in this thesis is given, along with the actual variables of the reservoir fluid's properties introduced into PROSPER.

3.3.1 Options Summary

This section is the starting point when a well is being modeled in PROSPER. Here, the application and principal well features are defined. As it can be seen in Table 2, the options selected in this thesis are the following:

Table 2 Well's features selected

Fluid	Oil and Water
Method	Black Oil
Separator	Single – Stage Separator
Emulsions	No
Hydrates	Disable Warning
Water Viscosity	Use Default Correlation
Viscosity Model	Newtonian Fluid
Flow Type	Tubing Flow
Well Type	Producer
Artificial Lift	None
Predict	Pressure and Temperature (offshore)
Temperature Model	Rough Approximation
Range	Full System
Well Completion's Type	Cased Hole
Sand Control	None
Inflow Type	Single Branch
Gas Coning	No

The model used for the PVT calculations is the Black Oil one. A brief characterization of this type of simulator has been given earlier in this thesis.

Moving on, the well is a single branch producing one, with no sand control and with a cased hole. As far as the fluids' rheology is concerned, all the liquid phases were considered to be Newtonian ones, since most of the times that is indeed the case for the reservoir fluids flowing in the wellbore. In addition, no artificial lift's system was added and both the emulsions and the hydrates were not taken into consideration.

Emulsions are defined as droplets of an immiscible fluid dispersed into another also non miscible one. They can be formed when reservoir and injection fluids are mixed, as well as after fluid's filtration or an acidizing treatment. They result in vast problems in the separation of the liquid phases, and to pumps' corrosion.

Hydrates, on the other side are solid shaped particles that look like ice, which are formed when natural gas and water are mixed at low temperatures and high pressures. They can be formed in pipelines and in gas gathering, compression and/or transmission facilities and they mainly affect the surface facilities of an oilfield.

Since nothing of the above is the case in the system under consideration, as it was previously mentioned in Table 1, both of these selections are disabled.

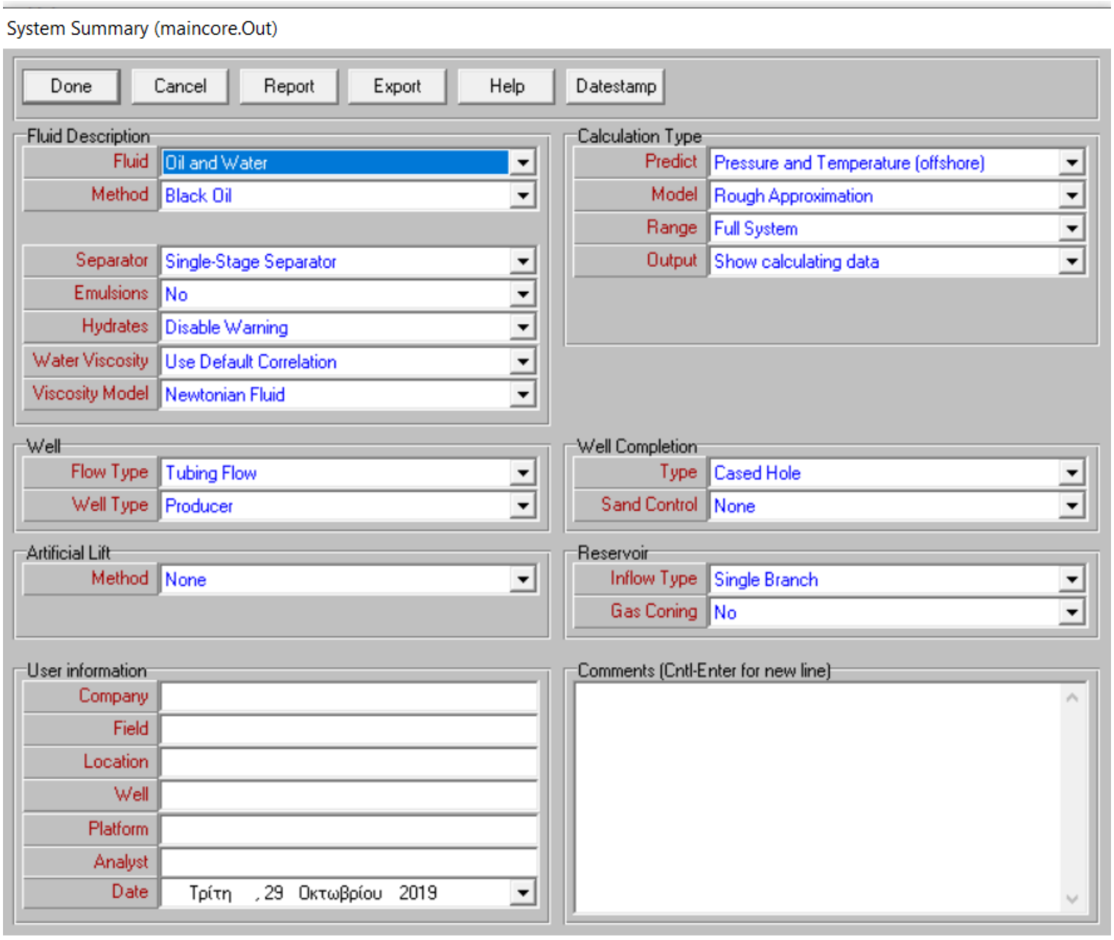


Figure 4 Options summary section

For the calculation of water viscosity, the default correlation of PROSPER was used. All the empirical formulae implemented in this software, have been taken by the McCain's 'Properties of Petroleum Fluids' book. Under the default selection, μ_w depends on temperature and water salinity. A pressure corrected correlation is also available in the software, but it was not used since water viscosity doesn't vary significantly with pressure. This is due to the fact that the amount of gas possibly dissolved in the water has a minimal effect on its viscosity. It is worth mentioning that the range of viscosity of oilfield water at reservoir conditions is almost always less than 1 cP.

To predict temperature, the Rough Approximation model was used. Heat loss is calculated from the well to the surroundings, the average heat capacity of the fluids and the temperature difference between the fluids and the formation. The temperature modeling of a well is of a vital importance, since temperature changes affect the average fluid properties, which in turn will alter the pressure drop calculations.

3.3.2 PVT Data Input

Aiming at the prediction of pressure and temperature changes from the reservoir, along the well bore and flow line tubular to the wellhead, basic field data is necessary to be introduced to the system. When only basic field data is available, like in the case under examination, and the user has selected the black oil model approach to do so, the properties asked to be filled by the user are the ones shown in Figure 5. More specifically, the surface PVT data of solution GOR, API gravity, gas gravity and water salinity are used as input. This data gives a rough description of the fluid's thermodynamic behavior.

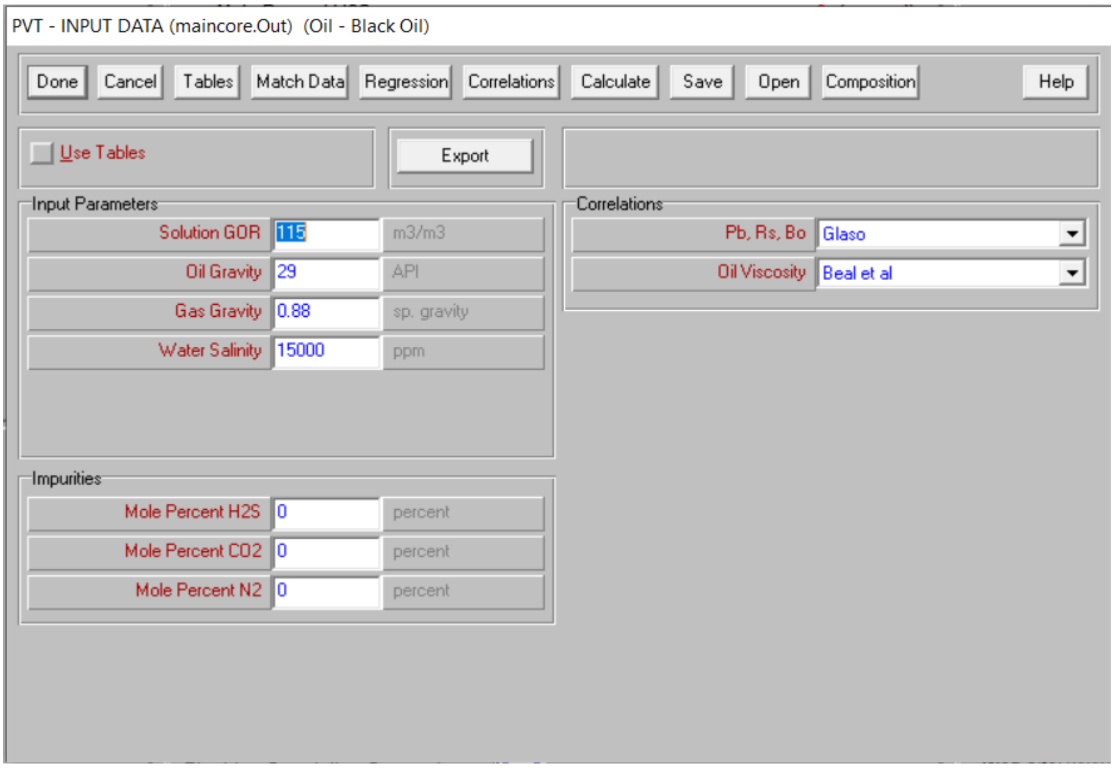


Figure 5 PVT data Input section

Following, when not only basic fluid data, but also some PVT laboratory measurements are available, the program can modify the black oil correlations to best fit the experimental data through the use of a non – linear regression technique. The flash data available is introduced in the Match Data section as seen in Figure 6. The utilized data in this case is the GOR, oil FVF and oil viscosity at the initial reservoir pressure and at the bubble point one, along with the reservoir temperature that, as it can be also seen in Figure 6, equals to 171 ◦F.

Here, it should be mentioned that the numbers shown in Figures 5 and 6 indeed correspond to one of the fluids utilized in this study. However, in this section they are only mentioned to illustrate the steps of setting up a model in PROSPER.

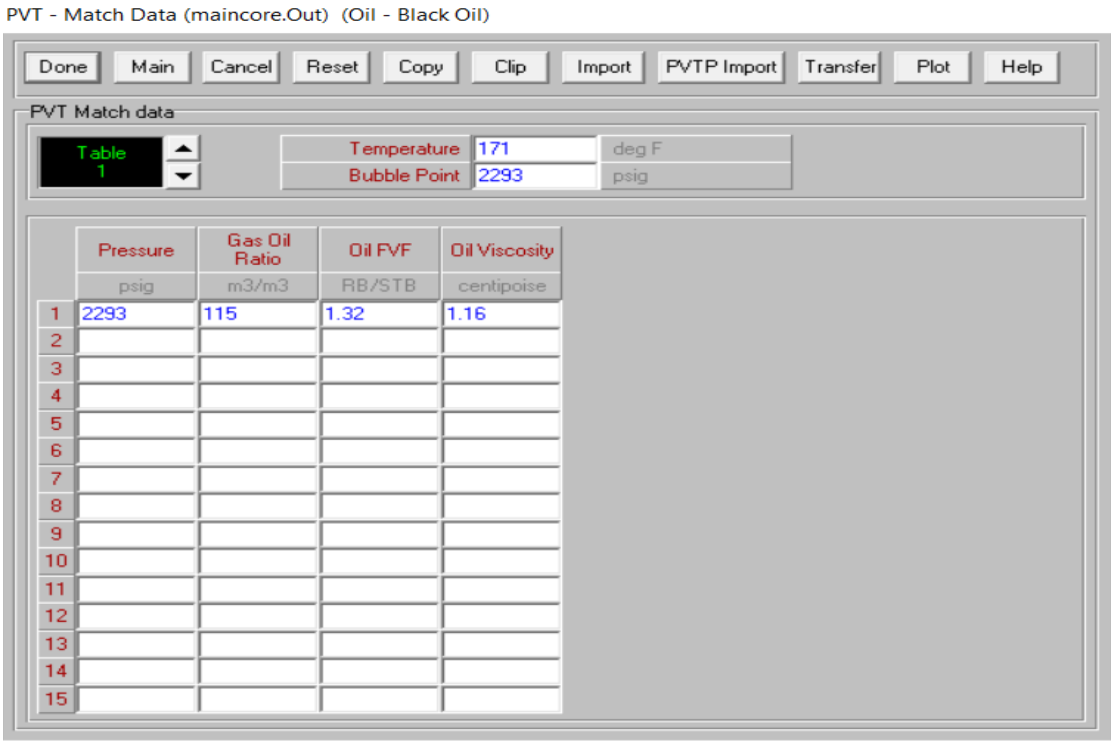


Figure 6 PVT match data section

3.3.3 Equipment Data Input

In this section the well's deviation survey, hardware, formation temperature profile and average heat capacities are defined (Figure 7). All well data presented in these sections, were common in all runs tested.

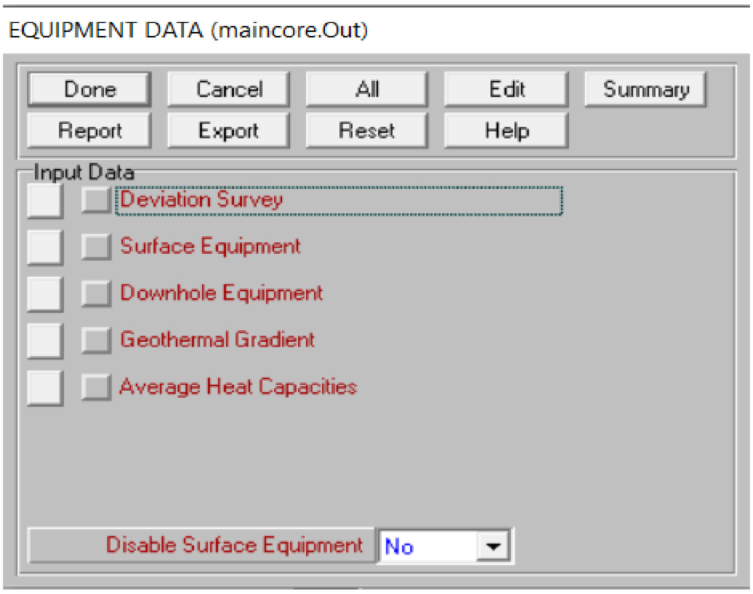


Figure 7 Equipment data Input menu

3.3.4 Deviation Survey

In this research, the well is a 'build and hold' one. This kind of wells consists of a relatively shallow kick off point, a buildup section and a tangent section. They are drilled vertically from surface to the kick off point, which in this well lies at a TVD of 600 ft, and as this point is reached, the well starts exhibiting an inclination angle of a constant step. When the maximum angle is reached in the desired target depth, the angle is kept constant.

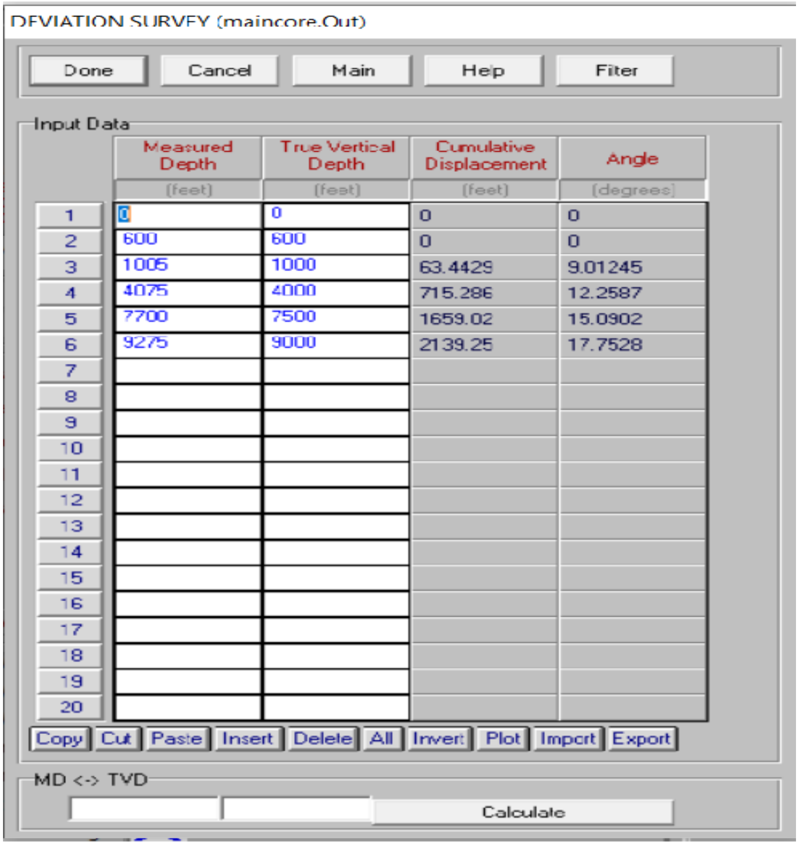


Figure 8 Deviation survey data input section

For the deviation survey to be generated by PROSPER, measured pairs of data points along the wellpath for the measured depth (MD) and the corresponding true vertical depth (TVD) are needed to be introduced to the software (Figure 8).

Measured Depth is the total length of the wellbore measured along the actual well path, while True Vertical Depth is the vertical distance from the surface to the point of interest. The MD and TVD are two very crucial variables since the calculation of the pressure losses due to friction and gravity respectively, depend on them. PROSPER estimates the trajectory of the well, by linearly interpolating two continuous measured depths, a procedure done for each pair of MD points. Having the aforementioned data, the software estimates the inclination angle and the cumulative horizontal displacement at each depth that was introduced.

In Figure 9 the profile of the well is illustrated, showing the cumulative displacement on the x axis and the MD and TVD on the left and right y axis, respectively.

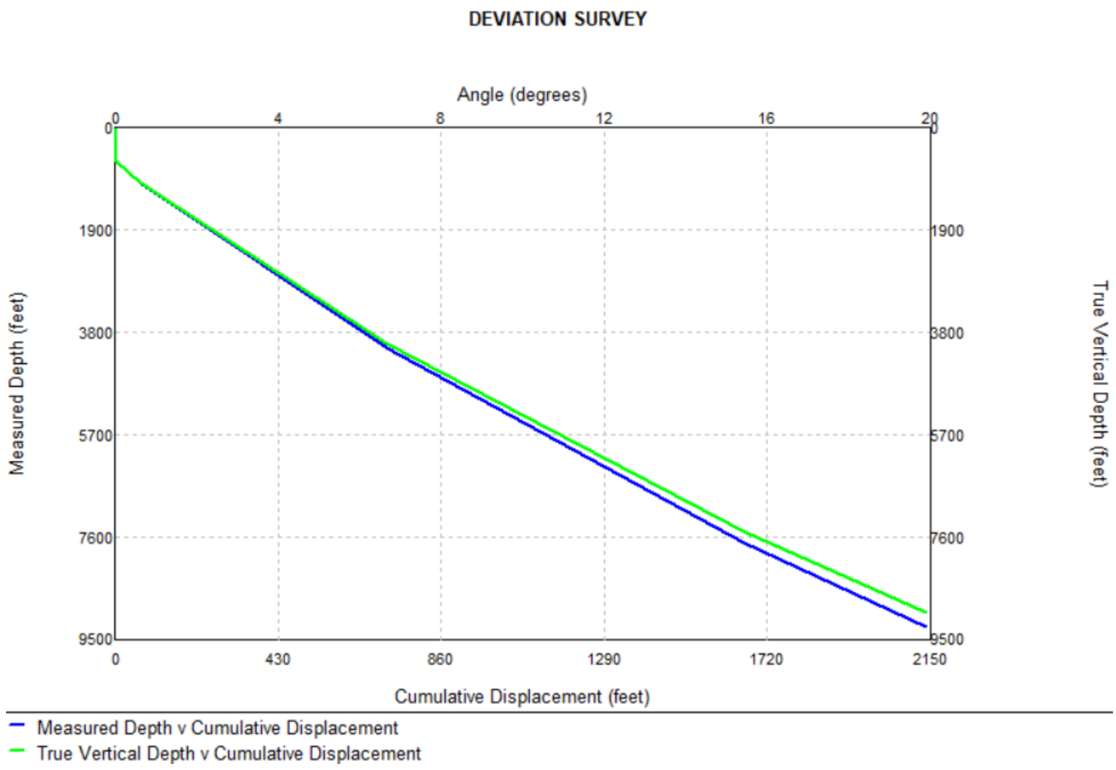


Figure 9 Well's Profile

3.3.5 Downhole Equipment

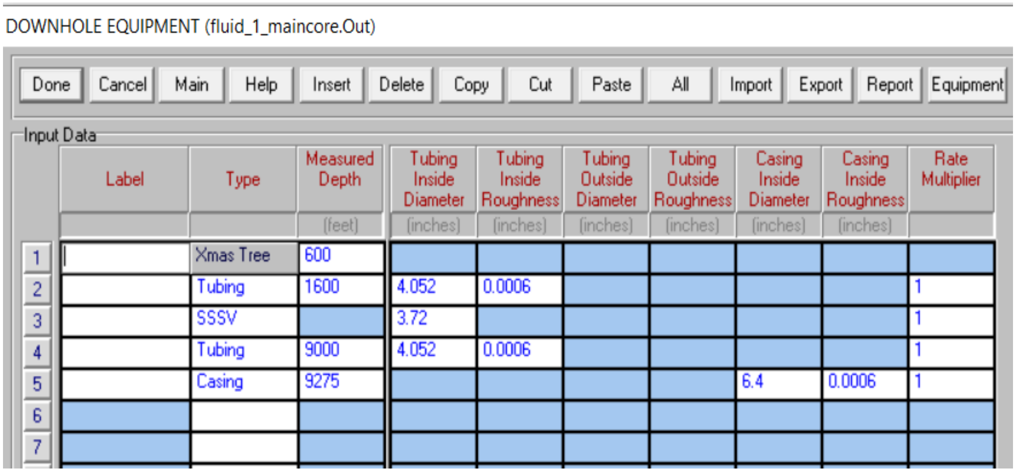
In this section, the path that the fluid will follow up to surface is defined, counting from the bottom hole up to the wellhead. This step is of a vital importance for the calculation of the VLP of the well, as well as the temperature and pressure gradients.

Before describing of downhole equipment, it must be clarified that although the well modeled in this thesis is an offshore one, the separator equipment was chosen to be on the seabed, next to the Xmas tree. That is why the network practically stops at the Xmas tree.

As it can be seen in Figure 10, in the respective section of the software the downhole completion data was entered. PROSPER automatically inserts the Xmas tree as the first downhole equipment item, which in this case lies at an MD equal to 600 ft. The last specified depth is considered to be the bottom - hole depth, which in this case equals to 9275 ft MD, the final depth point that the production casing reaches.

Finally, in brief the downhole completions data entered are:

- A production tubing of ID 4.052''ending at 9000 ft
- A subsurface safety valve (SSV) of ID 3.72" that has been installed at 1600 ft.
- A production casing ending bottom – hole (9275 ft) with an ID of 6.4"
- The roughness of all pipelines is equal to 0.0006 inches



DOWNHOLE EQUIPMENT (fluid_1_maincore.Out)

Done | Cancel | Main | Help | Insert | Delete | Copy | Cut | Paste | All | Import | Export | Report | Equipment

Input Data

	Label	Type	Measured Depth (feet)	Tubing Inside Diameter (inches)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (inches)	Tubing Outside Roughness (inches)	Casing Inside Diameter (inches)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	600							
2		Tubing	1600	4.052	0.0006					1
3		SSSV		3.72						1
4		Tubing	9000	4.052	0.0006					1
5		Casing	9275					6.4	0.0006	1
6										
7										

Figure 10 Downhole equipment data input section

Regarding the rate multiplier at the last column of the table in Figure 10, it is a variable that enables the simulation of pressure losses that are related to dual completion wells. Since the well under examination is a single branch one, this variable was set to its default value which equals to unity.

Following, in Figure 11 a schematic representation of the down - hole equipment as it was illustrated by PROSPER is shown.

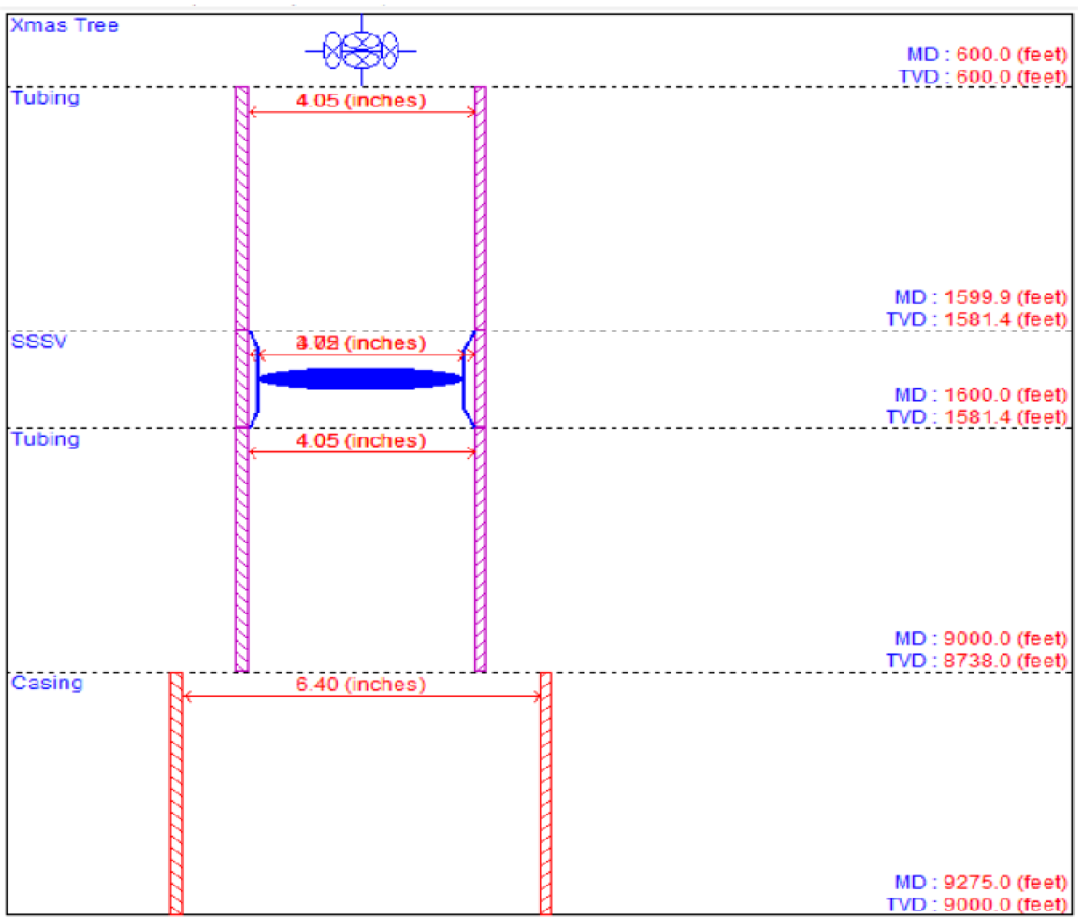


Figure 11 Downhole equipment's simple schematic

3.3.6 Geothermal Gradient

As temperature plays an important role to pressure drop calculations, the geothermal gradient (i.e. rate of increasing temperature of the surrounding formation with respect to increasing depth) and average heat capacities (ratio of the amount of heat energy transferred to oil, water or gas over the resulting increase in their temperature) are also taken into consideration.

In this part of PROSPER, the formation temperature profile is introduced. A minimum of two pairs of depth and temperature points is required for the procedure to be held, since the software uses linear interpolation between the entered points in order to estimate the distribution of the formation temperature. In this case, the temperature at surface, Xmas tree and bottom - hole depth were entered to the system.

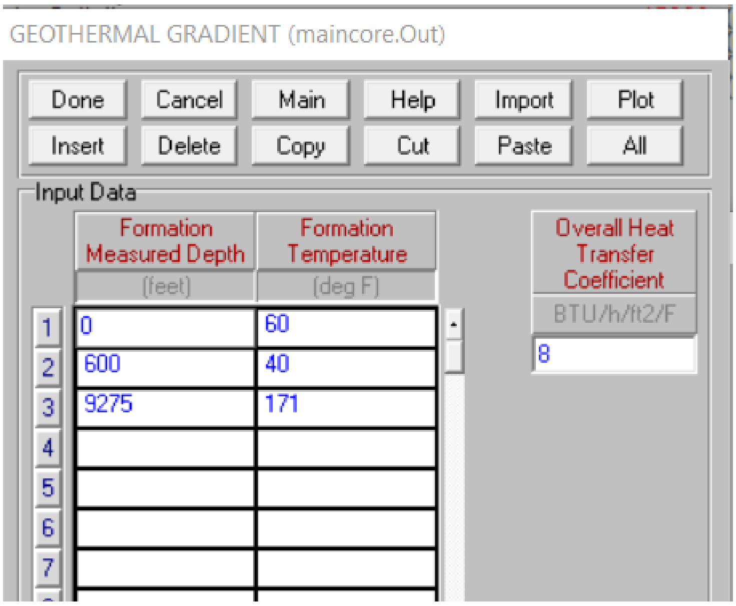


Figure 12 Geothermal gradient data input screen

As it can be seen in Figure 12, temperature decreases between the depth of 0 and 600 ft of depth. More specifically, at zero depth atmospheric conditions prevail, so the temperature equals to 60°F, while at seabed (600 ft) the temperature lowers to 40°F. That is because an offshore well is modeled, meaning that in this depth difference only water exists which is always colder than the formation, which starts from seabed and downwards. Here it must be emphasized that in this study, the network starts at the seabed, thus the temperature decline in the sea does not affect the calculations performed. The temperature at zero depth was introduced to the Geothermal Gradient section of PROSPER, in case the separator equipment was moved up to the surface, so the temperature at this depth would be needed.

The 'Rough Approximation' temperature model that was selected for the temperature simulation is based on the assumption that the heat transferred between the fluid and the surroundings depends on an overall heat transfer coefficient, also called the U value. Due to this, in the respective tab of the screen in Figure 9, a value describing the resistance to heat flow by all the different heat transfer mechanisms from the well to its surroundings was introduced.

3.3.7 Average Heat Capacities

The average heat capacities of oil, gas and water are also used in the selected temperature model, and that is why their introduction to the system is obligatory. Their default values, that were selected in this case, give satisfying results in oil wells of medium GOR. However, it should be mentioned that the actual values of C_p for oil and gas may vary, due to the fact that their composition also changes along the well.

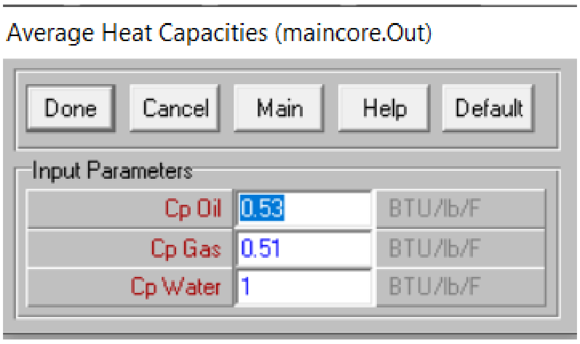


Figure 13 Average heat capacities data input screen

3.3.8 IPR Data Input

The Inflow Performance Relationship (IPR) is the definition of the flow that takes places from the reservoir and into the well. In the respective section of PROSPER, there is a list of over 20 inflow models, the selection of which depends mainly on the available data.

In this thesis, as it can be also seen in Figure 14 where the main IPR input screen of PROSPER is illustrated, the 'P.I entry' model was chosen. In this approach a straight – line inflow model is applied for the under saturated region of the reservoir, and the Vogel's empirical formula for the saturated one. The changing point after which the Vogel's model is used is the one where the pressure bottom – hole equals to bubble point, and the reservoir's flow is a two – phase one.

After the IPR model is selected, the reservoir properties, such as pressure and temperature, along with the fluid's properties are also inserted in the inflow data input section of PROSPER (right hand side of the screen in Figure 14). In addition, the Productivity Index is then introduced to the system, which in this thesis equals to PI = 5 STB/day/psi.

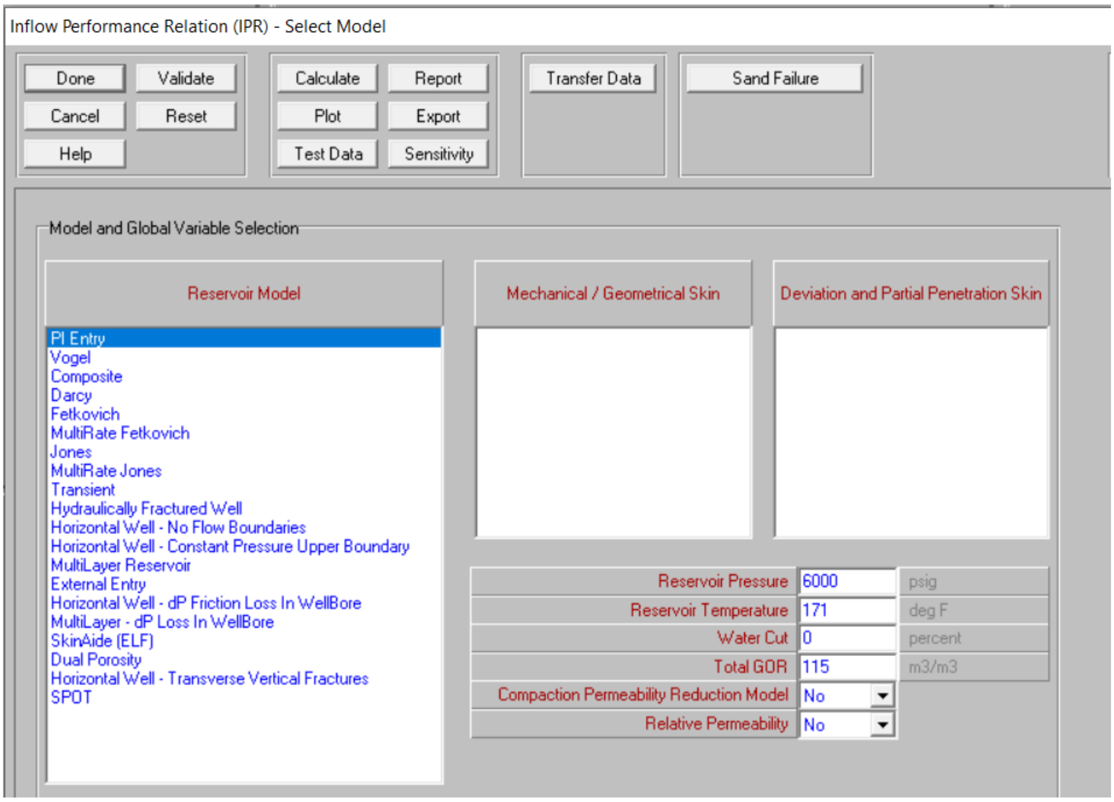


Figure 14 IPR data input section

Since the introduction of the aforementioned data has been done, the user is able to view the IPR curve. As seen in Figure 15, the curve illustrated shows how the liquid rate changes as bottom hole pressure decreases. Also, through the plotting of the IPR curve, the Absolute Open Flow (AOF) is also reported. The AOF equals to the potential maximum flow rate of a well corresponding to a flowing bottom – hole pressure (P_{wf}) equal to zero.

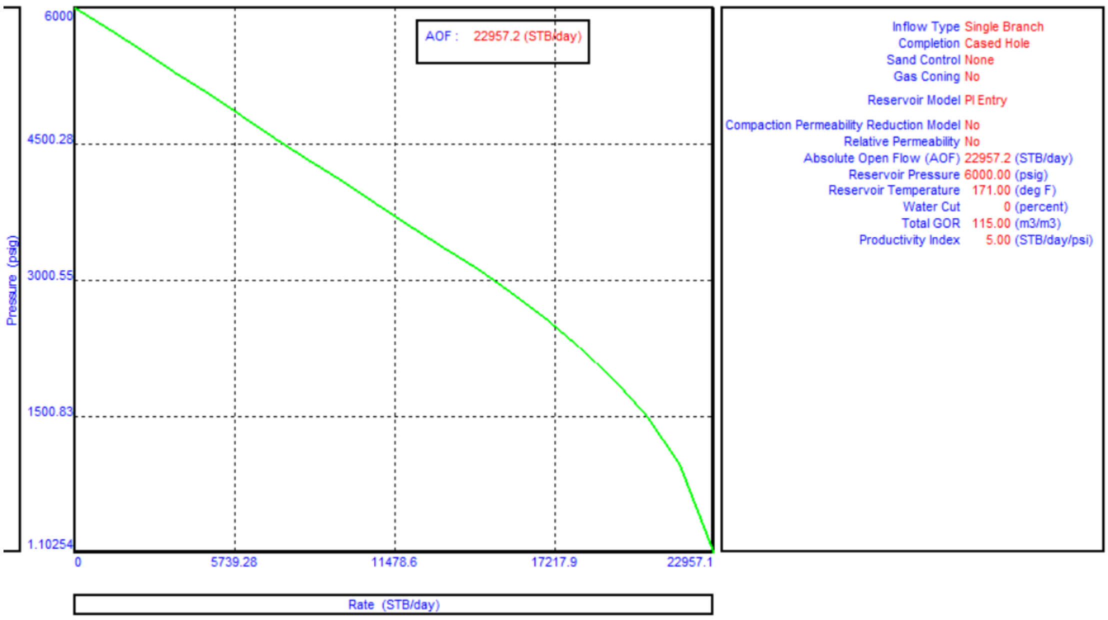


Figure 15 IPR Curve (BHP – psi - versus Liquid Rate – STB/day)

Finally, after all the needed data has been introduced in PROSPER, the user can also view the system's plot through which several valuable information can be acquired (Figure 16). The IPR/VLP relationship relates the wellbore flowing pressure to the production rate on the surface. Furthermore, the intersection point of the IPR and VLP curves provides the 'well deliverability', meaning the actual production rate of the well.

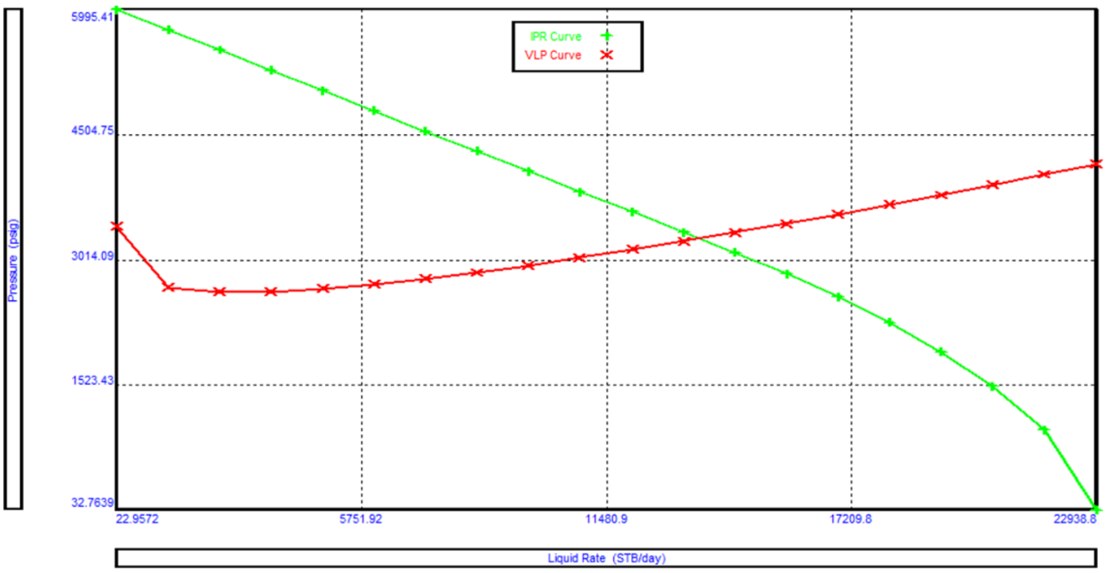


Figure 16 IPR/VLP curve intersection

Here, it should be mentioned that the graphs of Figures 15 and 16 are indeed results of one of the simulations done in this thesis. However, in this section they were mentioned only to illustrate the steps of setting up a model in PROSPER.

Chapter 4

Results

As it is already mentioned in this text, correlations are the only way to predict PVT properties of a fluid, when no or limited compositional data is available. These empirical formulae are based on physical properties as gas specific gravity (γ_g), Gas to Oil Ratio (GOR) and oil API gravity. Consequently, the best way to classify the fluids examined is by the type of oil, i.e. their API gravity (as illustrated in Figure 17).

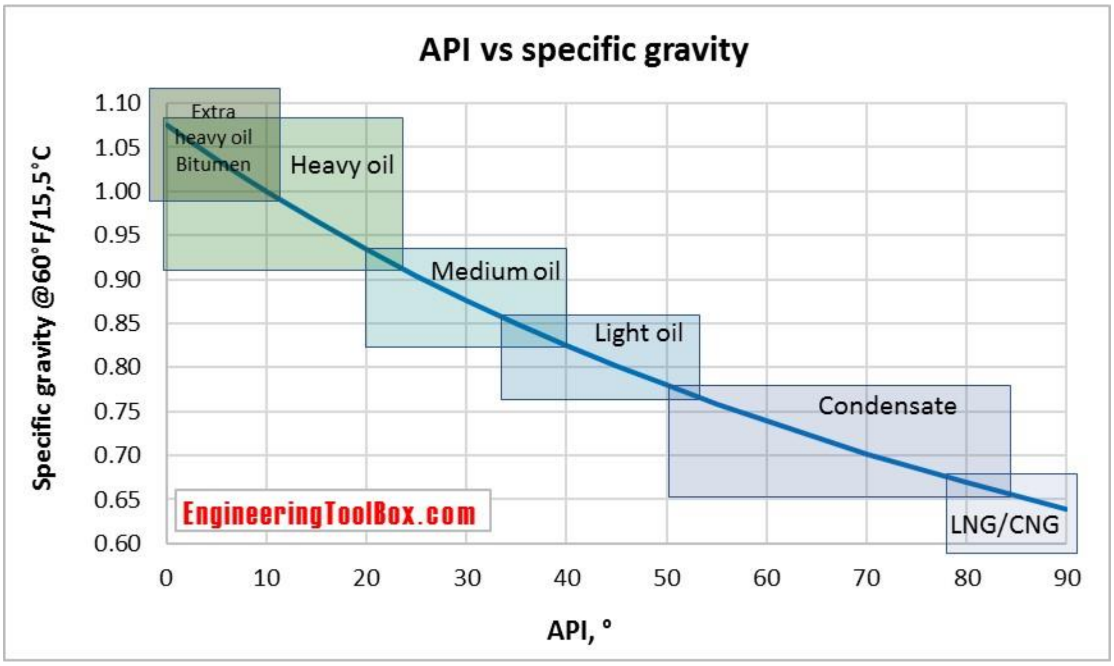


Figure 17 API versus Specific Gravity chart

The target of this thesis is to investigate if a user using the black oil model approach in PROSPER, can feel free to let the software make by itself the selection of any correlation available in it for the PVT calculations, or if this selection affects the results, thus implying that a thorough examination of these empirical formulae is necessary.

More specifically, in this study an effort was made to see if the differences in the calculations that PROSPER makes when using different, non – tuned, correlations are significant. Subsequently, these empirical formulae were tuned against field PVT data for each of the fluids examined. This was done so as to see the extend to which these differences in the fluid properties calculations have been reduced. Another crucial factor observed in this stage was which of these correlations deviated least from the experimental data, during the matching process.

The empirical formula that showed less tuning, is the one that fits best the field data of the fluid under examination. That is because the less deviation and/or tuning a correlation shows during the aforementioned process in a software, the highest is the conservation of this empirical formula's originality and the less is its distortion in order to fit the experimental measurements while the calculations of the properties for this fluid are done.

As mentioned before, the experimental data of two data points were introduced to PROSPER for each of the fluids. These field data were:

- Oil Formation Volume Factor (B_o) and Viscosity of oil (μ_o) at initial reservoir pressure

- Oil Formation Volume Factor (B_o) and Viscosity of oil (μ_o) at bubble point pressure

Four different fluids were examined, for which several pressure scenaria were simulated so as to allow for a variety of flow regimes in th wellbores to be examined. These pressure scenaria were for Reservoir Pressure equal to 6000, 5000, 4000 and 3000 psi. In case the lowest ressure scenaria showed that the well is dead, meaning there is no production, further runs were performed in order to see what is the lowest reservoir pressure for which there is a flow in the well.

The fluids examined are categorized into the two groups presented in Table 3:

Table 3 Fluid categories

Name	Type	API	GOR (m^3/m^3)	μ_i (cP)	μ_b (cP)	$B_o@P_i$ (rb/stb)	$B_o@P_b$ (rb/stb)
Fluid 3	MEDIUM	25.383	44.4	3.08	2.27	1.11	1.14
Fluid 4		23.756	61.4	4.41	3.68	1.21	1.23
Fluid 1	LIGHT	29	115	1.46	1.16	1.27	1.32
Fluid 6		33.978	151.4	0.44	0.39	1.55	1.64

To confirm the selection of the correlation that meets the above requirements as the best fit one for the specific fluid, the following criteria were checked, in the priority that they are given:

i. The match parameters a, b associated with each fluid property for all the correlations.

During the matching process, PROSPER performs a non – linear regression that applies a multiplier for the gravity term (Parameter a) and a shift, or else called a multiplier for the friction term, (Parameter b) to all correlations applicable in this software. In case these two parameters differ from 1 and 0 respectively, that means that there is an inconsistency between the PVT property calculated by the software and the field values that have already been introduced to the system.

Consequently, this inconsistency will also influence the VLP and IPR calculations due to the fact that fluid properties such as density and viscosity are present in these calculations [3]. Thus, the closest these two parameters are to 1 and 0, the better the fit of the correlation to the field data of the fluid. Here, it should be mentioned that Parameter a plays a much more important role to the selection of the correlation than Parameter b, the reason for which will become clear in the graphs that follow.

Therefore, the first criterion that was taken under consideration in all scenaria simulated, was which of the four correlations tested resulted to the smallest deviation and shifting for Parameters a and b, that were associated with the P_b, GOR and B_o at P_b properties.

So during the investigation that was done in this thesis, to evaluate which correlation fits best the fluid tested at each time, the first thing checked was the deviation of Parameter a from unity and then the shifting of Parameter b from 0. The one that led to the smallest differences in these two (and foremost in Parameter a) was considered to be the best one.

The numerical evaluation of these parameters is followed by the plotting of the fluid properties affected by the correlation's selection, for a visual check of the fit quality to be performed. In this way, it is very easy to visualize how the tuning of the correlation affects the fitting on the curve of the field data.

ii. Oil and gas flow rate before and after tuning and Absolute Open Flow (AOF) before and after tuning.

Moving on, after the first step for the selection was done, checking the following differences for each empirical formula tested, also took place:

- $\Delta_{qoil\_bef\text{-}after}$
- $\Delta_{qgas\_bef\text{-}after}$
- $\Delta_{AOF\_bef\text{-}after}$.

The correlation exhibiting minimum variation in these differences is characterized by the conservation of its originality during the tuning process in order to fit the field data.

If this inquiry indicates that the correlation which met the requirements of the first criterion is the one that does so also with the second criterion that means that the validity of this selection is even more strengthened.

These two criteria are the main ones that were taken into consideration in order for the correlation's selection to be held.

iii. The depth at which saturation pressure (P_b) is reached in the well for each fluid and all correlations.

After the tuning process was completed, for each fluid and all correlations, a Sensitivity Analysis of Pressure versus Depth took place, through which PROSPER estimated the VLP and IPR. From this analysis, the system allows the user to examine the values of the fluid properties from the bottom up to the top node pressure selected (which in this research was the depth bottom – hole and the Xmas tree depth, respectively).

What is done here is that basically the software divides the VLP and IPR in sections (dP/dZ) in order to proceed with the gradient calculations. Clearly, the more depth sections of VLP and IPR taken, the more accurate the model will be.

VLP and IPR calculations involve physical properties of the fluid, which are density, viscosity and oil volume factor. Considering that by utilizing different correlations, the BHP and the depth at which saturation pressure is reached are also affected in indirectly.

Having these facts as a base, it was concluded that the depth difference between bottom – hole and bubble point pressures can possibly be used as an additional indirect criterion in the correlation's selection.

4.1 Results after Flow Simulation of Fluid 1

As it can be seen in Table 4, the API degree of the fluid mentioned is 29. That means this fluid can be classified either as a medium, or as a light oil. However, by looking further at the other data, such as viscosity of oil at bubble point and specific gravity, this fluid is certainly a light oil.

Table 4 PVT data of fluid 1

Property	Units	Value
GOR	m^3/m^3	115
API	API	29
S_g		0,88
P_i	psi	6513
T_{res}	◦F	171
P_b	psi	2293
$Bo_{@Pb}$		1,32
$\mu o_{@Pb}$	cP	1,16
$Bo_{@Pi}$		1,27
$\mu o_{@Pi}$	cP	1,46
Water salinity	ppm	15000

4.1.1 Monitoring of matching parameters a and b

As previously clarified, the most important criterion on the selection of the best correlation, is the deviation of parameters a and b associated with each fluid property from 1 and 0, respectively. To monitor these differences, a monitoring of the Correlation Parameters section of PROSPER, as it is illustrated in Figure 18, took place in each scenario examined.

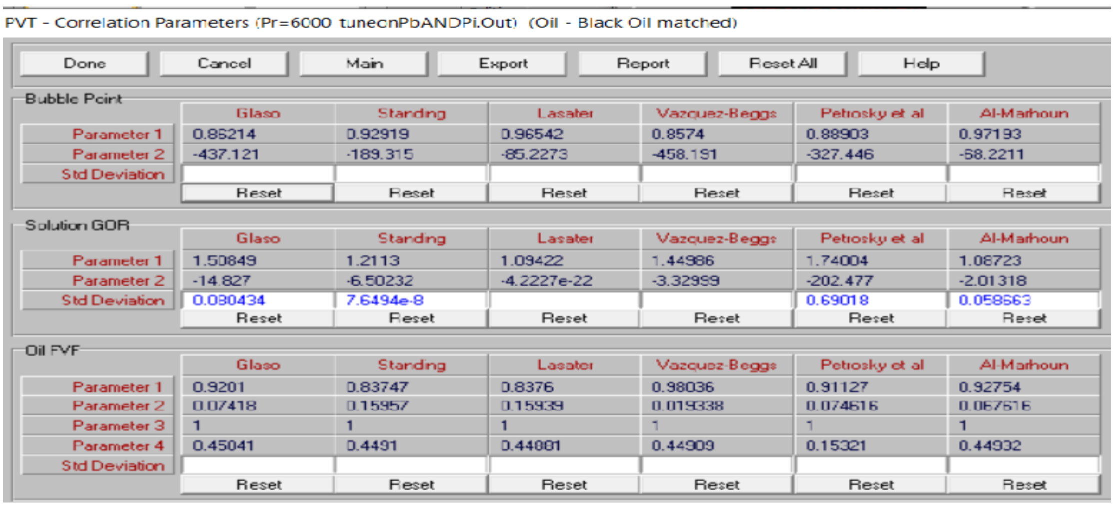


Figure 18 Matching Parameters a and b of Pb, GOR and Bo, for fluid 1

Regarding fluid 1, the correlation whose matching parameters showed less deviation in the majority of the tuned PVT properties was the Al – Marhoun one. More specifically, when Al – Marhoun was selected:

- For Bubble Point Pressure (P_b) – Parameter a = 0,97193 and Parameter b = -68,211 psi
- For Gas to Oil Ratio (GOR) – Parameter a = 1,08723 and Parameter b = -2,01318 scf/stb
- For Oil Volume Factor (B_o) – Matching Parameters a and b exhibited variables closer to the desired ones, by selecting the Vasquez – Beggs empirical formula (Par.a = 0,98036 and Par.b = 0,019338 rb/stb). Also Parameters c and d differentiated least from the field data when Vasquez – Beggs was selected (Par.c = 1,44986 and Par.d = 3,32999 rb/stb). However, since PROSPER uses correlations from the same developer for P_b, R_s and B_o, the common best – fitted one to the field data had to be selected, which was the one by Al – Marhoun.

Here it should be mentioned that, the two additional match parameters (Parameters c and d) were introduced to allow this fluid property to be tuned separately below (Parameter a and b) and above (Par c and d) the bubble point pressure. That is due to the fact that standard correlations don't always model accurately B_o above the saturation pressure.

4.1.2 Correlation Comparison

After monitoring the matching parameters a and b associated with P_b, GOR and B_o, the Al – Marhoun correlation was selected as the one deviating least from the field data set already introduced to the system. A further step to reassure that the aforementioned selection was the correct one, was the plotting of Oil Volume Factor and Gas – to Oil - Ratio against the pressure range that has been introduced to PROSPER. The concept of this action was to visually inspect that the empirical formula exhibiting the closest match to the field data, before the regression procedure is carried out, is the Al –Marhoun one. Furthermore, the range of differences the correlations exhibit in the fluid properties calculations was another thing examined.

In Figure 19 there is an illustration of the Gas – to – Oil – Ratio (GOR) versus pressure for each correlation examined, along with the field data of this property, before tuning was held. As it can be seen, all correlations have fitted perfectly the R_s at p_b value of 115 m^3/m^3. That is completely reasonable since this value is a field data that has already been introduced in PROSPER, for pressures equal and above bubble point. As previously mentioned the solution Gas – to – Oil – Ratio is a property in which all correlations are based, thus this perfect fit was expected.

However, that is not the case for bubble point pressure. As it is obvious in Figure 19, the P_b of 2293 psi was not matched by no correlation selected. On the contrary, these four correlations have resulted in totally different calculations regarding the bubble point pressure, varying in a range of approximately 800 psi. Nevertheless, it is worth mentioning that the Al – Marhoun empirical formula gave the closest result by estimating P_b at 2389 psi.

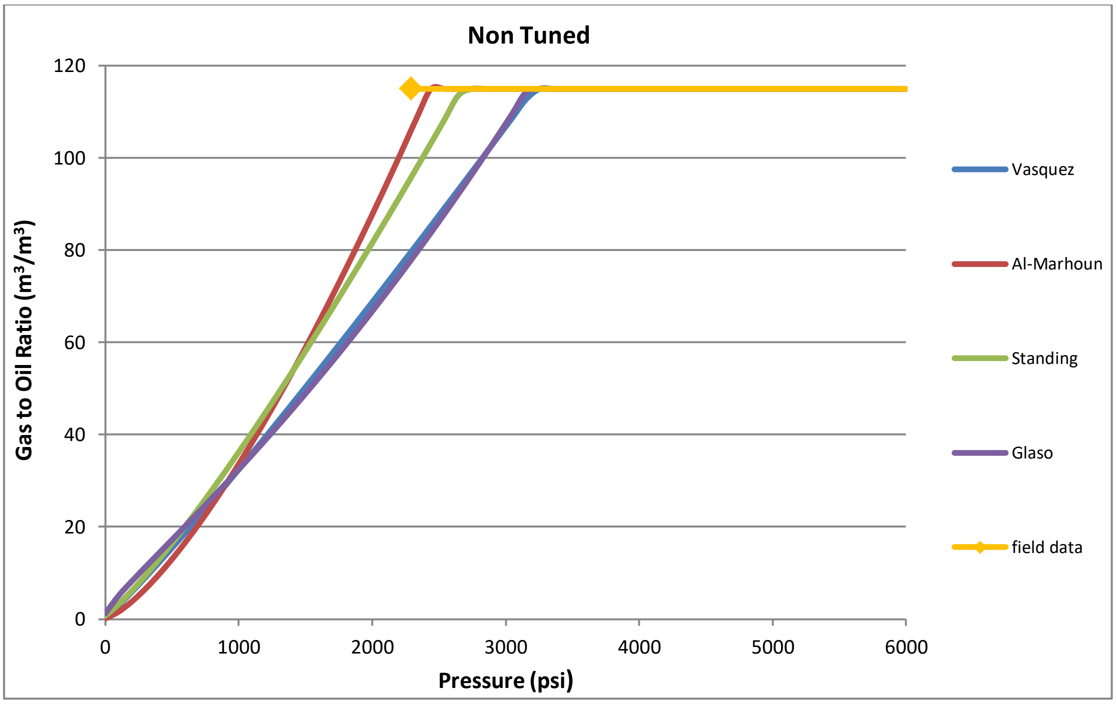


Figure 19 GOR versus Pressure graph for fluid one, before tuning on field data – Field data and all tested correlations plotted

Moving on, after tuning was carried out the variation of bubble point calculations among the correlations examined, has been diminished. As it can be seen in Figure 20, all four empirical formulae have resulted in the same accurate saturation pressure of 2293 psi. Regarding R_s above bubble point estimation, as mentioned above, it had already been calculated correctly having selected all the tested calculations.

A final observation done by comparing Figures 19 and 20, is that the curve deviated the least both upwards and to the left side is the Al – Marhoun one (red curve). This basically is the visualization of the aforementioned fact that Parameters a and b deviated the least from the field data, when Al – Marhoun was selected. To freshen up this fact, Parameter a which is associated with the upwards or downwards deviation the curve has to take in order to fit the experimental one, has the less deviation from unity (1,08723). Also Parameter b which is associated with the left or right shifting of the curve, differentiates the least from zero when Al – Marhoun is selected.

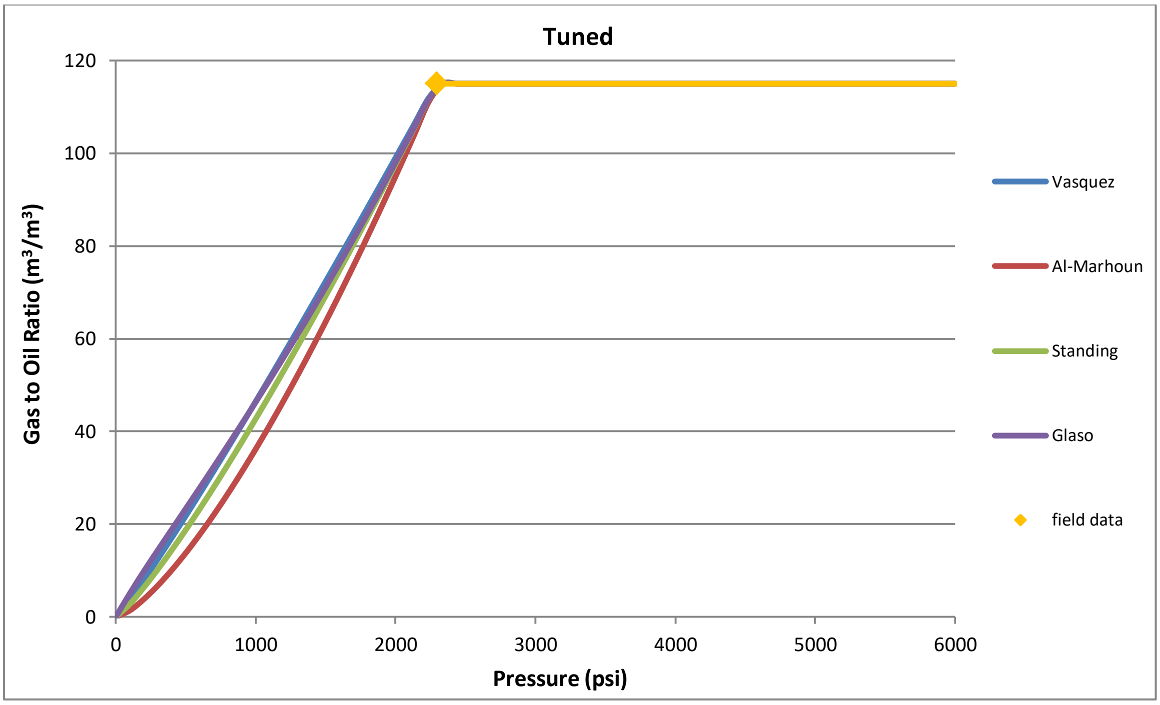


Figure 20 GOR versus Pressure graph for fluid one, after tuning on field data – Field data and all tested correlations plotted

Next is an illustration of the Oil Volume Factor versus Pressure for each correlation examined, along with the field data of this property, before tuning was held (Figure 21). Obviously, the same tendency that was observed in the above graphs (GOR versus Pressure) regarding the bubble point estimation characterizes all four correlations also in this graph. None of them has succeeded in estimating the desired P_b of 2293 psi.

Regarding B_o, as it can be seen the calculations of the correlations examined vary widely and almost neither of them has accurately predicted the B_o given in the field data for the saturation and the initial reservoir pressure.

The only case that a correlation fitted almost perfectly the field data was for Vasquez – Beggs (blue curve). Through it the oil formation volume factor for the saturation pressure was estimated to be 1,326 when the field data indeed were for a B_0 at P_b equal to 1,32.

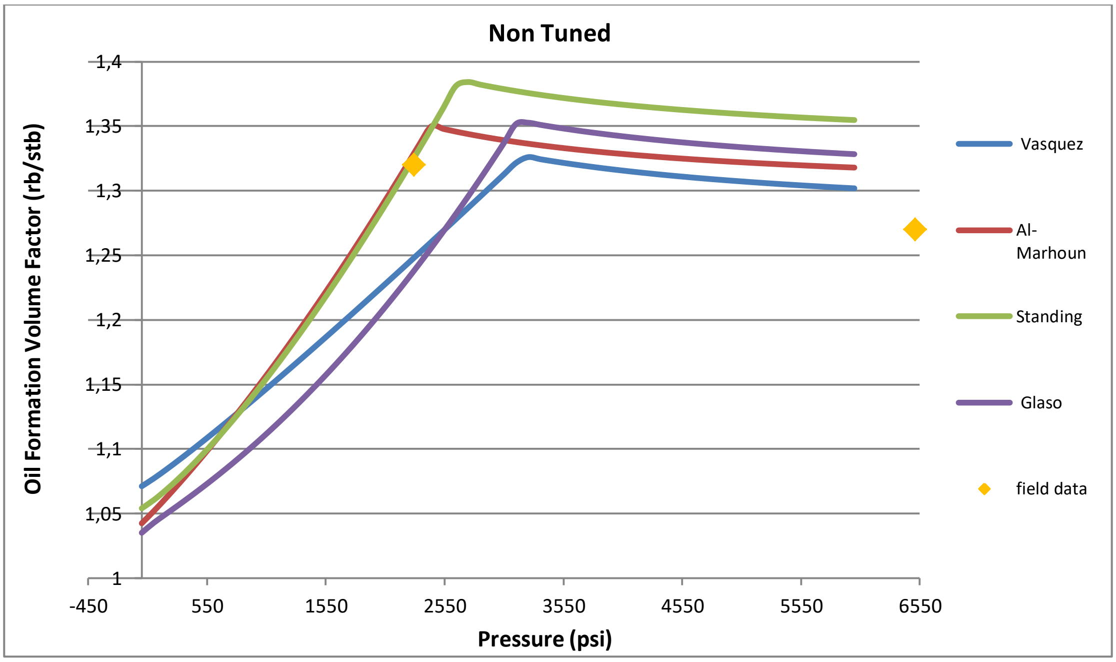


Figure 21 Bo versus Pressure graph for fluid one, before tuning on field data – Field data and all tested correlations plotted

Regarding the alteration of the correlation curves before and after tuning, in Figure 22 there is an illustration of B_o versus Pressure after tuning was performed. As it is observed, for pressures above bubble point, the curves of all four correlations coincide. That is because; in PROSPER all the calculations for the pressure range above bubble point are performed using the same correlation related to the isothermal compressibility. Thus, it is a reasonable consequence to have the exact same outcome regardless the empirical formula selected.

Furthermore, here it must be mentioned that the empirical formula that deviated least from the field data during the B_o calculations for this fluid was the Vasquez – Beggs. That is justified through the match parameters. Parameter a of Vasquez – Beggs, that is related with the downwards deviation of the correlation below P_b, is closer to unity than all the others. Also Parameter b, which is related with the left or right shifting of the correlation's curve below Pb, differentiated the least from zero in case of Vasquez – Beggs.

As far as Parameters c and d are concerned, they have to do with the same deviations as a and b but for pressures above bubble point. The first one is equal to 1 in all cases while the second is almost the same. That is due to the same correlation used for this pressure range.

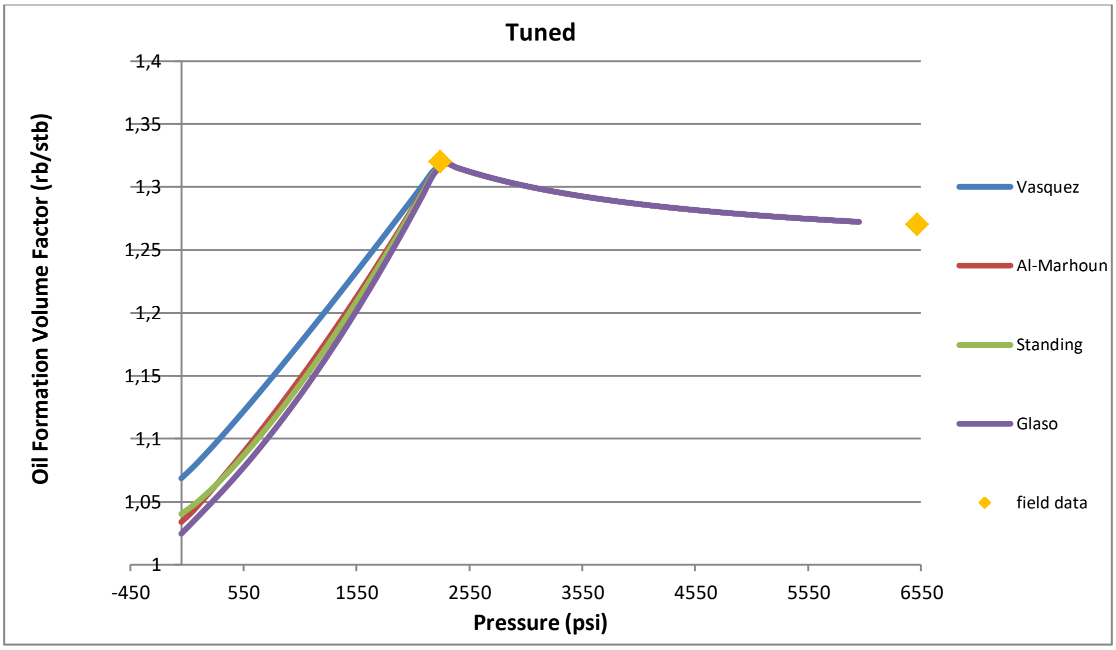


Figure 22 Bo versus Pressure graph for fluid one after tuning on field data – Field data and all tested correlations plotted

Although the above observations regarding oil volume factor don't match with the selection of Al – Marhoun correlation as the best option to fit the field data of the fluid under examination, as previously mentioned, in PROSPER the correlation selected must be the common best for all the three properties.

Nevertheless, it is worth saying that in case an engineer was using PROSPER for this specific fluid and needed to have the best possible estimations regarding the B_o property, then Vasquez – Beggs correlation was the best selection to be made. Otherwise, the Al – Marhoun correlation was the desired one.

Concluding, after all the above were examined, it can be said that even for a simple fluid of low volatility, letting PROSPER make the selection of a correlation by itself, and not tuning it is not recommended. Based on the simulations of this thesis, bubble point prediction will not be successful with any of the correlations examined, and their calculations will vary from each other in a wide pressure range.

In addition, a crucial fluid property such B_o, cannot be accurately predicted when no tuning on field data has been held.

Furthermore, another fact that needs to be clarified is that, even after performing a matching process on field data, PROSPER should not choose freely which correlation to utilize. That is because even if the fluid properties have been fitted perfectly to the field data introduced to the software, the user of it should always pay attention to the deviation of the match parameters of each property, in order to reassure the preservation of its originality.

Concluding, it must be specified that the selection of Al – Marhoun as the best correlation to fit the field data, was only for the specific fluid under examination.

4.1.3 Differences in the oil and gas flow rate before and after tuning, using all correlations tested

In Tables 5 and 6, the liquid and gas flow rate results of each correlation used are given, for fluid 1 and for a reservoir pressure of 6000 psi. After studying the liquid flow rates, presented in Table 5, it can be seen that with no tuning there is a variation among the different correlations examined of approximately 122 standard barrels in the daily production of this well.

The average production succeeded under the aforementioned reservoir pressure, again with no tuning, equals to 13658 standard barrels per day (average estimation of flow rate before tuning, for the correlations tested). Thus, the difference in the flow rate estimation among the different correlations examined is approximately equal to 1% of their actual estimations for the oil that will be produced.

Table 5 Liquid Flow rate results before and after tuning under a P_r = 6000 psi

Reservoir Pressure = 6000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δq_{oil}_bef-after**
Al-marhoun	13579	13364,9	**214,1**
Standing	13701,2	13288	413,2
Vasquez	13682,4	13318	364,4
Glaso	13668,1	13259,3	408,8

Therefore, for this type fluid, an engineer wanting to simply estimate the flow rates in order to proceed with a Nodal Analysis can choose freely any of these correlations to do so, since the variation in this estimation is not a countable number for any oil company. Additionally, in order to be even more certain for the accuracy of the predictions obtained by PROSPER, a tuning against field data for any of these correlations is recommended.

After the matching process was performed, the average daily oil production predicted through PROSPER was equal to 13308 standard barrels (average estimation of flow rate after tuning, for the correlations tested). The variation of the liquid flow rates among the four correlations examined was approximately 106 stb per day, which equals to 0,8% of the actual average oil production mentioned just above. Therefore, selecting any of these empirical formulae and simply tuning it against field data is far more than enough in case of a simple light fluid. Nevertheless, it should be mentioned again that to reassure the originality of the correlation in use, matching parameters should be monitored.

Table 6 Gas Flow rate results before and after tuning under a P_r = 6000 psi

Pressure = 6000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	8,813	8,66	**0,153**
Standing	8,892	8,61	0,282
Vasquez	8,88	8,63	0,25
Glaso	8,87	8,592	0,278

Moving on, another variable examined aiming to the selection of the best correlation for fluid 1, was the Absolute Open Flow. The percentage of the difference between the AOFs estimated for each of the empirical expressions before and after tuning was made. The results are shown in Table 7, for all the reservoir pressures tested.

As it can be seen, the smallest deviation in the percentages in question are again the ones calculated when the Al – Marhoun correlation was selected. Furthermore, as reservoir pressure decreases the percentage of this difference is increasing, regardless the correlation selected.

Table 7 Percentage of the difference between the AOF before and after tuning

P_{res} (psi)	6000	5000	4000	3375	3000
Correlation	**Δ**$_{AOF\_aft\text{-}bef}$(*%)				
Al-marhoun	1,2	1,6	2,1	2,7	3,2
Standing	3,5	4,4	6	7,7	9,3
Vasquez	8,9	11,4	15,9	20,4	18,9
Glaso	8,5	10,8	15	19,8	18,9

This trend of $\Delta_{AOF\_aft\text{-}bef}$ is justified by the following arguments:

a. The PVT lab data introduced in the software were only about two pressure points. To be more specific, the B_o along with the μ_o under initial and bubble point pressure and the GOR were the only experimental data given. Also, during the tuning that took place, all correlations try and shift the curve that the correlation's equation creates as close as possible to the one governing the experimental data. This is done having as a base the PVT lab data inserted to the system. The ones available in this analysis are about pressures higher and equal to the saturation one. So the software in the cases of lower P_r makes bigger alterations, leading to higher deviations in the variables of the properties and, also to the flow rates, in order to give results as close as possible to the experimental ones.
b. As it is observed, the lower the P_r the less accurate/valid the results taken. In some of these cases, while before tuning, the reservoir was a saturated one ($P_r<P_b$), after that was performed the reservoir altered to an under saturated one. Thus, the reservoir conditions in this comparison were totally different, leading to higher variations in the flow rates (higher gas and liquid production before tuning in all cases discussed in this point) These cases are:
   - Pr = 5000 psi, having selected Vazquez's and Glaso's correlations
   - Pr = 4000 psi, having selected Vazquez's and Glaso's correlations
   - Pr = 3375 psi, having selected Standing's, Vazquez's and Glaso's correlations

The aforementioned tendency of the differences studied- along with the fact that Parameters a and b deviate less from 1 and 0 respectively when the same empirical formula was selected – indicates that the best – fit correlation against the field data introduced to PROSPER specifically for fluid 1 is the Al – Marhoun. That is because the slightest the deviation before and after tuning, the highest the accuracy of the results taken having selected this empirical formula.

4.1.4 Depth at which bubble point occurs

Let's now proceed in the evaluation of how much the estimation of the depth at which bubble point occurs differs, from a correlation to another, and if the tuning process is necessary regarding this variable. To do so, it should be reminded that the depth of the well bottom – hole equals to 9275 ft. As it can be seen in Table 6, with no tuning the estimations of the depth at which the flow will alter from a monophasic to a diphasic one, vary a lot in all pressure scenaria examined. More specifically, for example under a reservoir pressure of 6000 psi, the depth variation among the four correlations utilized, equals to approximately 2317 ft which equals to 800 m.

This is a countable difference indicating that the VLP calculations differ significantly when different correlations are implemented. Thus, as previously mentioned in this text, this indirectly results in differentiation in the physical fluid properties calculated by PROSPER (density and viscosity). Based on that, whoever uses this software should not let it choose freely the correlation utilized for the PVT correlations. In addition, under no circumstances the user must rely on the calculation done without tuning.

Moving on, by observing the depth results after the matching process against field data was performed it is obvious that all correlations lead to the same depth value for the bubble point occurrence. This along with the conclusions regarding the non – tuned scenario, means that although the variable under examination in this part of the thesis is an indirect criterion for the validity of the results, none correlation should be utilized without first tuning it. Also, even when it is tuned, since the non – tuned results had such a depth variation, a monitoring of at least the match parameters is considered as necessary.

Regarding the depth results of the simulations performed for the specific fluid under examination, the following observations were made:

As it can be seen in Table 8, when Al – Marhoun correlation is selected the depth difference from bottom – hole to bubble point is the highest one, both before and after tuning was held. For the reasons previously mentioned in this text, when that is the case, anyone can consider this fact as an indirect proof that the selection regarding the correlation was correct in terms of system calculations.

Nevertheless, to emphasize the higher validity of the first two criteria mentioned above in this thesis, the following should be noted: If a correlation that is justified as the best – fit one based on the first two criteria, does not show this tendency in the depth difference between

BHP and P_b, this should not be considered as an accurate proof that the selection done is not valid.

Table 8 Bottom Measured Depth at which bubble point occurs

<table>
<tr><td>Pressure (psi)</td><td colspan="2">6000</td><td colspan="2">5000</td><td colspan="2">4000</td><td colspan="2">3375</td><td colspan="2">3000</td></tr>
<tr><td></td><td colspan="10">MD (ft) where Pb occurs</td></tr>
<tr><td>Tuning State</td><td>before</td><td>after</td><td>before</td><td>after</td><td>before</td><td>after</td><td>before</td><td>after</td><td>before</td><td>after</td></tr>
<tr><td>Al-Marhoun</td><td>6733,3</td><td rowspan="4">6250</td><td>7458,3</td><td rowspan="4">6975</td><td>8150</td><td rowspan="4">7458</td><td>8375</td><td>7700</td><td>8150</td><td rowspan="4">dead well</td></tr>
<tr><td>Standing</td><td>7458,3</td><td>8375</td><td>9050</td><td rowspan="3">already below Pb</td><td>7458,3</td><td rowspan="3">already below Pb</td></tr>
<tr><td>Vasquez</td><td>9050</td><td rowspan="2">already below Pb</td><td rowspan="2">already below Pb</td><td>7700</td></tr>
<tr><td>Glaso</td><td>9050</td><td>7458,3</td></tr>
</table>

Another observation done regarding the depth at which bubble point pressure is reached is that, as reservoir pressure increases bubble point occurs at swallower depths. This is physically valid, due to the fact that highest starting pressure means highest force with which the liquid evolves upwards, so it will reach a swallower depth until the bubble point occurs.

Bubble point occurs high compared to the depth of the reservoir (approximately 1km upwards). This indicates that no matter the chosen correlation, the difference in the liquid rate value computed won't be of high significance, and also that the use of correlations instead of a compositional model is valid, due to the fact that the needed time and height for the fluid to change from monophasic to diphasic is provided, so a more analytical model is not needed in this case. This is indeed confirmed through the simulations that took place. By examining Tables 5 and 6, it is noticed that the shifting of q, regardless the correlation selected is not significant in most cases.

4.2 Results after Flow Simulation of Fluid 4

As it can be seen in Table 9, the API degree of the fluid mentioned is 23,75. That means this fluid is classified as medium volatility oil. This is also justified by other physical properties of the fluid, such as viscosity and the variation of oil volume factor from the initial reservoir pressure to the bubble point.

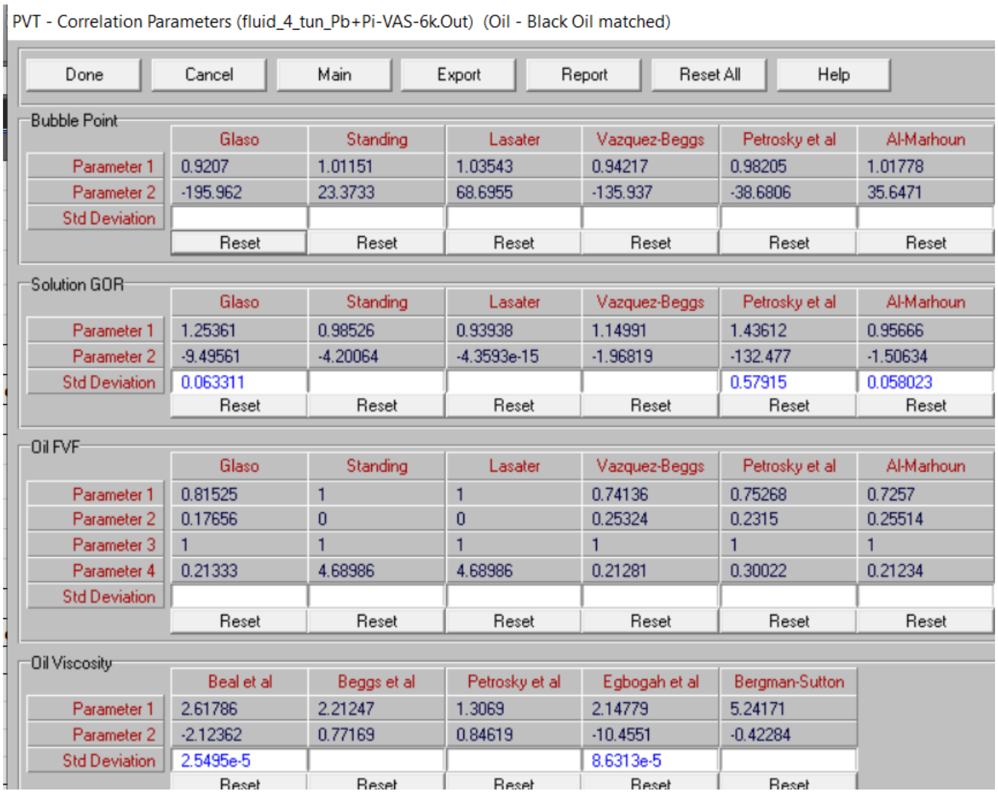
Table 9 PVT data of fluid 4

Property	Units	Value
GOR	m^3/m^3	61,41
API	API	23,75
S_g		0,835
P_i	psi	4000
T_{res}	◦F	197,6
P_b	psi	2077
$Bo_{@Pb}$		1,15
$\mu o_{@Pb}$	cP	3,68
$Bo_{@Pi}$		1,13
$\mu o_{@Pi}$	cP	4,41
Water salinity	ppm	15000

4.2.1 Monitoring of matching parameters a and b

Regarding fluid 4, as it is illustrated in Figure 23, the correlation whose matching parameters were characterized by the less deviation in the majority of the tuned PVT properties was the one by Standing. More specifically, when this empirical formula was selected:

- Parameter a showed minimum deviation for P_b, GOR and B_o. As mentioned before, parameter a plays a more important role than b. Thus, by getting its minimum deviation for all three properties for the same correlation, enhances the validity of this formula.
- Parameter b doesn't show the minimum shifting for all three fluid properties, when Standing correlation is selected, but the majority of them does so. More specifically, parameter b for P_b and B_o indeed is characterized by this tendency, but for GOR its minimum value is resulted having selected Al - Marhoun correlation.
- By observing more thoroughly the parameters of B_o, it is found that for Standing Parameters a, b and c achieve their best values (1,0 and 1 respectively) meaning that they were fitted perfectly to the field data. Regarding Parameter d, its minimum shifting from 0 is achieved when Al – Marhoun is selected. Nevertheless, as previously said its significance for the fit in the pressure range above bubble point is of secondary importance.



PVT - Correlation Parameters (fluid_4_tun_Pb+Pi-VAS-6k.Out) (Oil - Black Oil matched)

Done | Cancel | Main | Export | Report | Reset All | Help

Bubble Point

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.9207	1.01151	1.03543	0.94217	0.98205	1.01778
Parameter 2	-195.962	23.3733	68.6955	-135.937	-38.6806	35.6471
Std Deviation						
	Reset	Reset	Reset	Reset	Reset	Reset

Solution GOR

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.25361	0.98526	0.93938	1.14991	1.43612	0.95666
Parameter 2	-9.49561	-4.20064	-4.3593e-15	-1.96819	-132.477	-1.50634
Std Deviation	0.063311				0.57915	0.058023
	Reset	Reset	Reset	Reset	Reset	Reset

Oil FVF

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.81525	1	1	0.74136	0.75268	0.7257
Parameter 2	0.17656	0	0	0.25324	0.2315	0.25514
Parameter 3	1	1	1	1	1	1
Parameter 4	0.21333	4.68986	4.68986	0.21281	0.30022	0.21234
Std Deviation						
	Reset	Reset	Reset	Reset	Reset	Reset

Oil Viscosity

	Beal et al	Beggs et al	Petrosky et al	Egbogah et al	Bergman-Sutton
Parameter 1	2.61786	2.21247	1.3069	2.14779	5.24171
Parameter 2	-2.12362	0.77169	0.84619	-10.4551	-0.42284
Std Deviation	2.5495e-5			8.6313e-5	
	Reset	Reset	Reset	Reset	Reset

Figure 23 Matching Parameters a and b of Pb, GOR and Bo, for fluid 4

4.2.2 Correlations Comparison

In Figure 24 the solution Gas – to – Oil – Ratio versus pressure for each correlation examined, along with the field data of this property, for fluid 4 and before tuning is illustrated. It is obvious that, all correlations have fitted perfectly the R_s value of 61,41 m^3/m^3. As also mentioned for the first fluid examined in this text, this was an expected outcome; the solution Gas – to – Oil – Ratio is a property that all correlations have as a fundamental variable in their calculations, thus this perfect fit was totally expected.

However, that is not the case for bubble point pressure. As it is obvious in Figure 24, no correlation exhibited the field variable of P_b equal to 2077 psi was found. On the contrary, these four correlations have resulted in totally different calculations regarding the bubble point pressure, varying in a range of approximately 465 psi. Nevertheless, it is worth mentioning that the Standing empirical formula gave the closest result by calculating Pb being equal to 2030 psi.

As it can be seen, the Standing curve (green curve) is showing less deviation from the experimental one (orange curve). This is a fact further justifying the selection of this correlation as the best one that was done during the monitoring of the match parameters.

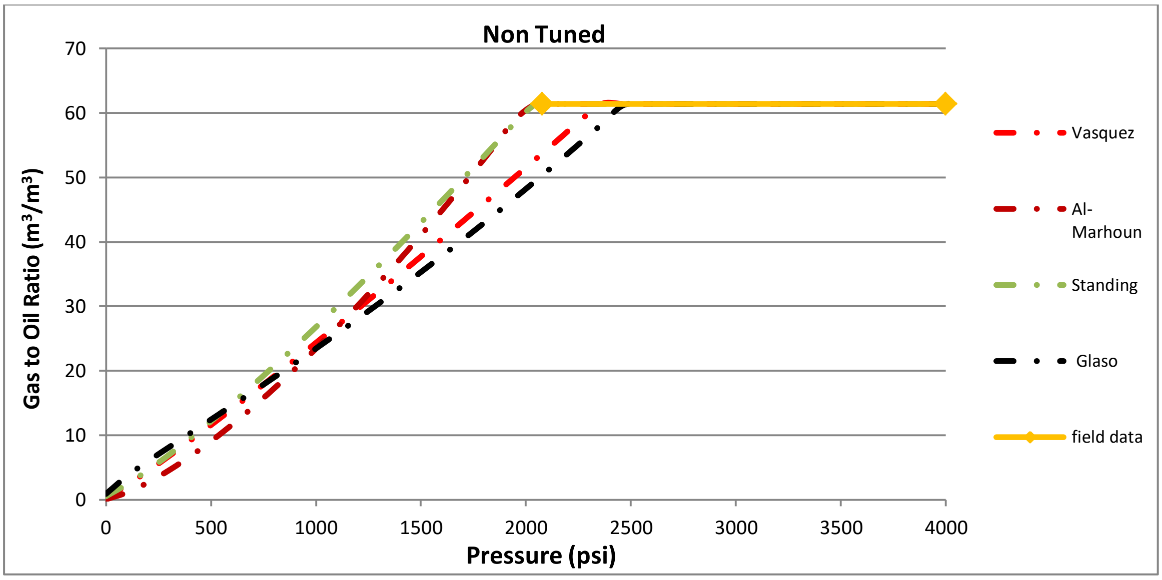


Figure 24 GOR versus Pressure graph for fluid four, before tuning on field data – Field data and all tested correlations plotted

Moving on, after tuning was carried out the variation of bubble point calculations among the correlations examined, has been diminished. As it can be seen in Figure 25, all four empirical formulae have resulted in the same accurate saturation pressure of 2077 psi. Regarding R_s above bubble point estimation, as mentioned above, it had already been calculated correctly having selected all the tested calculations, even when no tuning had being performed.

A further observation done by comparing Figures 24 and 25, is that the curve deviated the least both upwards and to the left side is the Standing (green curve). As in the previous fluid examined, this is just an illustration of the fact that for GOR the Match Parameters a and b deviated the least from the field data, when Standing was selected.

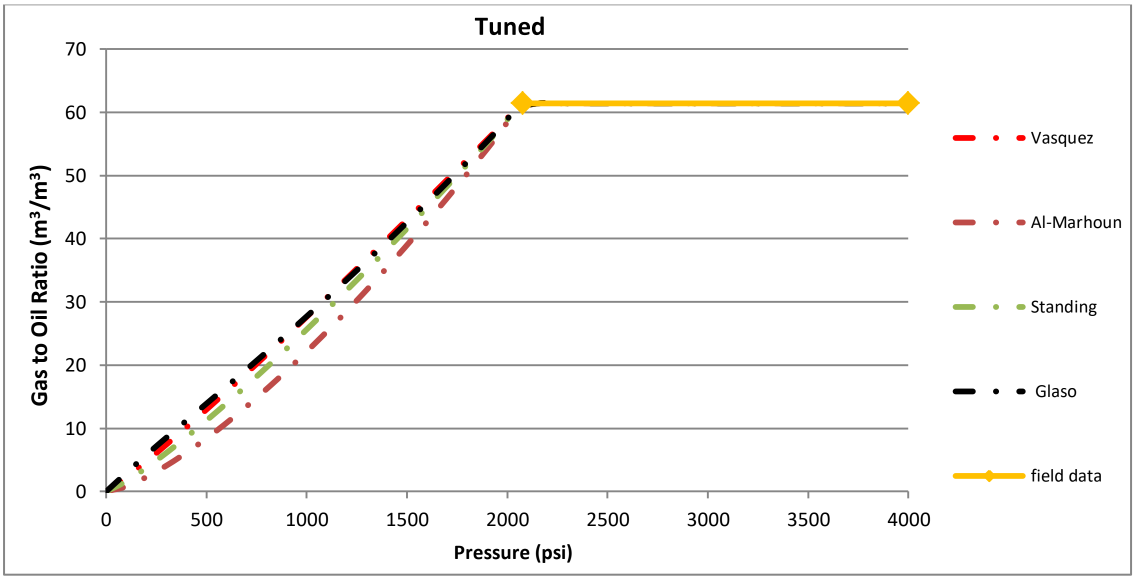


Figure 25 GOR versus Pressure graph for fluid four, after tuning on field data – Field data and all tested correlations plotted

Next is an illustration of the Oil Volume Factor versus Pressure for each correlation examined, along with the field data of this property, before tuning was held (Figure 26). Likewise, the same tendency of bubble point estimation that was observed in the above graphs for GOR versus Pressure, is also the case in these graphs. None of them has succeeded in estimating the desired P_b of 2293 psi. This is obviously completely justified, since these fluid properties were calculated simultaneously through PROSPER, for each correlation examined.

As regards B_o, it is more than obvious that the calculations of all four empirical formulae vary a lot. In addition, none of them has accurately predicted the B_o given in the field data for the saturation and the initial reservoir pressure.

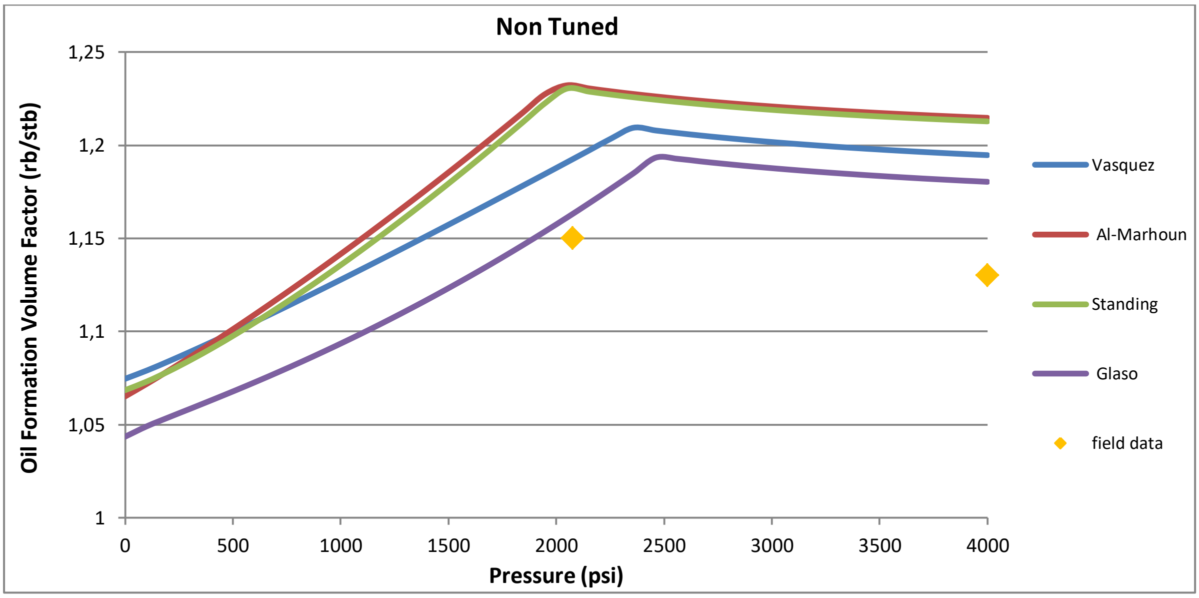


Figure 26 B_o versus Pressure graph for fluid four, before tuning on field data – Field data and all tested correlations plotted

Regarding the alteration of the correlation curves before and after tuning, in Figure 27 there is an illustration of B_o versus Pressure after tuning was performed. As it is observed, for pressures above bubble point, the curves of all correlations besides the Standing one coincide. The fact that the curves of three of these four empirical formulae coincide is explained through the following; PROSPER performs all the calculations for the monophasic region of the well, based on the utilization of the same correlation for the calculation of the compressibility factor. Consequently, this results in receiving the exact same curves for this pressure range, regardless the empirical formula selected.

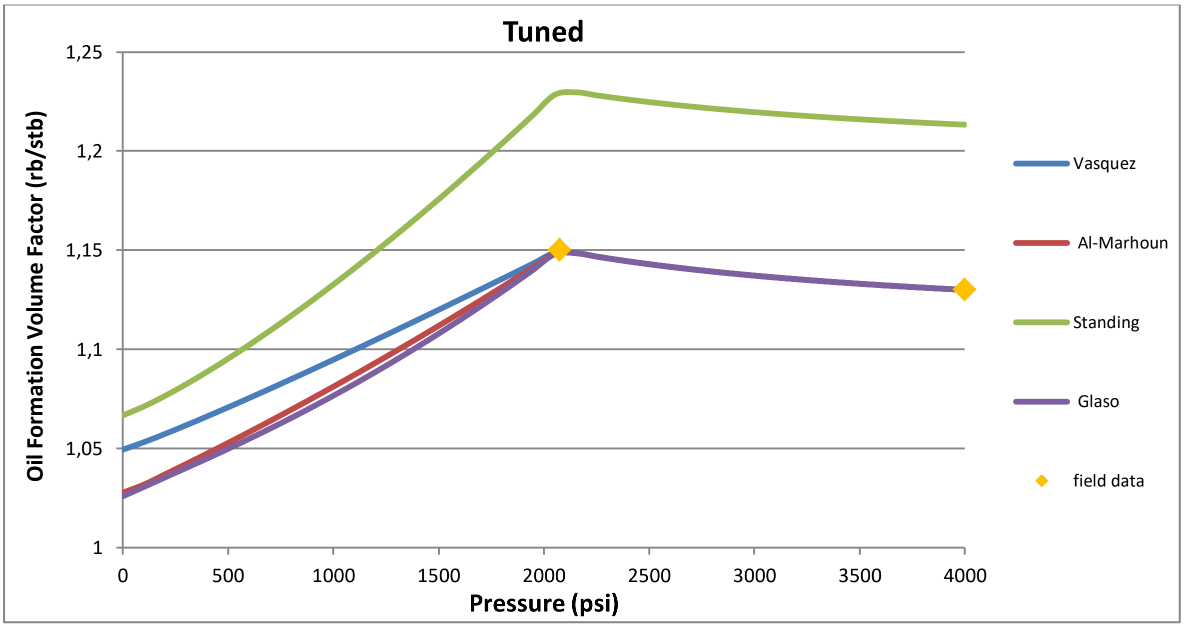


Figure 27 B_o versus Pressure graph for fluid four, after tuning on field data – Field data and all tested correlations plotted

However, as it can be seen in Figure 27, this “rule” does not apply in the curve of Standing correlation. In order to find the reason behind this, various things were investigated. The followings came as a result:

- Three of the four match parameters (a,b and c) for Standing get values dictating that the tuning process was not held for Standing correlation
- By dividing the field data of oil formation volume factor for bubble point and initial reservoir pressure (B_o at P_b/ B_o at P_i) by hand the outcome was different from the PROSPER calculation (0,935 against 1). This possibly indicates that the tuning of Standing correlation was not done correctly through PROSPER.
- Comparing the non – tuned and tuned graphs (Figure 26 and 27) before tuning Al – Marhoun and Standing curves were in the same B_o and pressure ranges. After tuning, Al – Marhoun deviated from its non – tuned curve both downwards and to the right, while Standing remained exactly the same.
- The exact same tendency was the situation in all pressure scenario examined for this fluid, when Standing correlation was used

All the above result in that, for some reason that was not feasible to be traced, PROSPER did not tune Standing correlation in this simulation. Maybe, there is a crack in the algorithm used that resulted in this inconsistency, but again that is just a simple hypothesis.

4.2.3 Differences in the oil and gas flow rate before and after tuning, using all correlations tested

In Tables 10 and 11, the liquid and gas flow rate results of each correlation used are given, for fluid 4 and when reservoir pressure was equal to 4000 psi. After an observation of the liquid flow rates, presented in Table 10, it is concluded that with no tuning there is a variation among the different correlations examined of approximately 546 standard barrels in the daily production of this well. The average production succeeded under the aforementioned reservoir pressure, again with no tuning, equals to 5768 standard barrels per day (average estimation of flow rate before tuning, for the correlations tested).

Therefore, the difference in the flow rate estimation among the different correlations examined is equal to 9,4% of their actual estimations for the oil that it is predicted to be produced. This is a countable variation in financial terms. If an engineer using PROSPER does not select the appropriate correlation and results in such a difference between the predicted volume produced from the well, and the actual volume that was produced, he/she will face major consequences.

Thus, in such a fluid, all users should carefully select which correlation to utilize for the PVT calculations, even for the simplest predictions.

Table 10 Liquid Flow rate results before and after tuning under a P_r = 4000 psi

Reservoir Pressure = 4000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δqoil_bef-after**
Al-marhoun	6052	5069	983
Standing	5980	5487	493
Vasquez	5509,5	4996	513,5
Glaso	5531,7	5064,5	467,2

As it can be seen in the right column of Table 11, the difference of gas flow rate before and after tuning gets its minimum value when having selected Standing correlation. Under almost all pressure scenaria tested, the tendency of all the flow rates was the same, resulting in the selection of Standing correlation as the best one. That is why the results of only one of these scenarios are discussed thoroughly below. Nevertheless, the detailed results of all the simulations are given in Appendix A.

After the matching process was performed, the average daily oil production predicted through PROSPER was equal to 5154 standard barrels (average estimation of flow rate after tuning, for the correlations tested). The variation of the liquid flow rates among the four correlations examined was approximately 490 stb per day, which equals to 9,5% of the actual average oil production mentioned just above.

What is concluded from this is that, even after tuning is performed, the variation of the predicted flow rate is still very high, among the different correlations examined. That means that, also after the matching process, the user of PROSPER should not choose a correlation thoughtlessly.

Table 11 Gas Flow rate results before and after tuning under a P_r = 4000 psi

Pressure = 4000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	3,71	3,1	0,61
Standing	3,66	3,4	0,26
Vasquez	3,38	3	0,38
Glaso	3,4	3,1	0,3

Another variable examined aiming to the selection of the best correlation for fluid 4, was the Absolute Open Flow. The percentage of the difference between the AOFs estimated for each of the empirical expressions before and after tuning was made. The results are shown in Table 12, for all the reservoir pressures tested.

As it can be seen, the smallest deviation in the percentages in question was again exhibited when the Standing correlation was selected. That is a further proof, enhancing the validity of this empirical formula been correctly chosen as the best one to fit the field data of the fluid under examination.

Table 12 Percentage of the difference between the AOF before and after tuning

P_{res} (psi)	6000	5000	4000	3000
Correlation	$\Delta_{AOF\_aft\text{-}bef}$(*%)			
Al-marhoun	6	8	1	1,5
Standing	4	5	7	1
Vasquez	2,4	3,1	4,1	6,2
Glaso	3,6	4,5	6	9,2

4.2.4 Depth at which bubble point occurs

Let's now finish the evaluation by observing how much the estimation of the depth at which bubble point occurs differs from a correlation to another, and if the tuning process is necessary regarding this variable. As it is remembered, the depth of the well bottom – hole equals to 9275 ft. The variations examined here are going to be the ones regarding an initial reservoir pressure of 4000 psi, because this was also the field data introduced to PROSPER for fluid 4.

As it can be seen, the results of the depth before and after the matching process was held are the same, the reservoir in bottom – hole pressure in both cases is a saturated one. That means that there is no depth difference between bottom – hole and bubble point, because the pressure was already below the saturation one. Thus the flow was diphasic from the beginning.

Table 13 Bottom Measured Depth at which bubble point occurs

<table>
<tr><td>Pressure (psi)</td><td colspan="2">6000</td><td colspan="2">5000</td><td colspan="2">4000</td><td colspan="2">3000</td></tr>
<tr><td></td><td colspan="8">MD (ft) where Pb occurs</td></tr>
<tr><td>Tuning State</td><td>before</td><td>after</td><td>before</td><td>after</td><td>before</td><td>after</td><td>before</td><td>after</td></tr>
<tr><td>Al-Marhoun</td><td>8375</td><td>8150</td><td rowspan="4">already below Pb</td><td>9050</td><td rowspan="4">already below Pb</td><td rowspan="4">already below Pb</td><td rowspan="4">already below Pb</td><td rowspan="4">dead well</td></tr>
<tr><td>Standing</td><td rowspan="3">already below Pb</td><td>9050</td><td rowspan="3">already below Pb</td></tr>
<tr><td>Vasquez</td><td>already below Pb</td></tr>
<tr><td>Glaso</td><td>8825</td></tr>
</table>

However this does not mean either that a user can let the software choose freely which correlation to utilize, or that tuning is not necessary to be performed. That is due to the fact that here the user is dealing from the beginning with a diphasic flow, which means that the calculations made cannot be trusted.

Chapter 5

Conclusions

The main requirement in a reservoir/well flow simulation, in any wellbore managing software is the availability of PVT data for the reservoir fluid. However, at early production stages these data are of a limited extent. In this case, Black Oil Model approach is utilized for the prediction of the PVT properties at any pressure and temperature during a reservoir's depletion. Numerous black oil correlations are available in all reservoir and well modeling software, whose utilization results to the prediction of PVT properties of a reservoir fluid.

The purpose of this thesis was to evaluate the prediction performance of the four most well - known black oil empirical formulae, before and after they were tuned against PVT measurements for different types of oil. Through the study described in the sections above, it was concluded that letting PROSPER software make the selection of a correlation by itself, and not tuning it is not recommended.

As far as all the non – tuned scenaria tested are concerned, bubble point prediction is not successful with any of the correlations examined, and their calculations vary from each other in a wide pressure range. Additionally, the crucial fluid property of B_o, cannot be accurately predicted when no tuning on field data has been held. On the contrary, the solution Gas – to – Oil – Ratio for the monophasic fluid (R_s) is fitted perfectly from all four correlations examined. This fact is completely justified since R_S is a field variable already introduced in PROSPER for pressures equal and above bubble point.

Furthermore, the results taken after all the tuned scenaria were examined, showed that even after a matching process on field data is performed PROSPER is not valid to choose freely which correlation to utilize. Although the fluid properties fit perfectly to the field data introduced to the software, the user is always obligated to pay attention to the deviation of the match parameters of each property, in order to reassure the preservation of its originality.

To accomplish that, the first step to be made is to investigate which of the correlations results in the smallest deviation and shifting for the Match Parameters that are associated with the P_b, GOR and B_o at P_b properties. In this sense this was the first criterion taken under consideration in all simulations examined. After this numerical evaluation of the parameters, the plotting of the fluid properties was made, for a visual check of the fit quality.

The graphs showed that after tuning is carried out the variation of bubble point calculations is diminished and all four empirical formulae result in the same accurate saturation pressure. Regarding R_s above bubble point estimation, as mentioned above, it is already calculated correctly having selected all the tested calculations, even when no tuning had being performed.

As far as B_o property is concerned, after tuning is carried out for the monophasic fluid the curves of all four correlations coincide. That is because in PROSPER all the calculations for the pressure range above bubble point are performed using the same correlation related the isothermal compressibility. Here, it is worth mentioning that in one of the fluids examined (fluid 4), Standing correlation did not follow this "rule". Several things were investigated to find the reason behind this inconsistency, but no solid conclusion could be drawn. Due to that, an additional investigation is going to be made.

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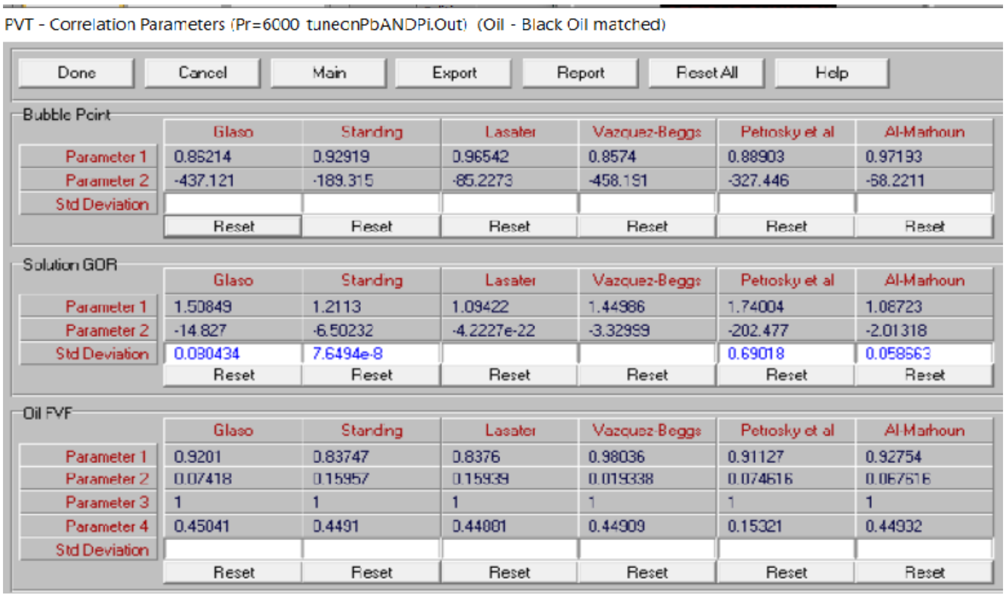
Appendix A

Monitoring of match parameters

Fluid 1



PVT - Correlation Parameters (Pr=6000 tunecnPbANDPi.Out) (Oil - Black Oil matched)

Done Cancel Main Export Report Reset All Help

Bubble Point

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.85214	0.92919	0.96542	0.8574	0.88903	0.97193
Parameter 2	-437.121	-189.315	-85.2273	-458.191	-327.446	-58.2211
Std Deviation						
	Reset	Reset	Reset	Reset	Reset	Reset

Solution GOR

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.50849	1.2113	1.09422	1.44986	1.74004	1.08723
Parameter 2	-14.827	-6.50232	-4.2227e-22	-3.32999	-202.477	-2.01318
Std Deviation	0.080434	7.6494e-8			0.69018	0.058563
	Reset	Reset	Reset	Reset	Reset	Reset

Oil FVF

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.9201	0.83747	0.8376	0.98036	0.91127	0.92754
Parameter 2	0.07418	0.15957	0.15939	0.019338	0.074616	0.067516
Parameter 3	1	1	1	1	1	1
Parameter 4	0.45041	0.4491	0.44881	0.44909	0.15321	0.44932
Std Deviation						
	Reset	Reset	Reset	Reset	Reset	Reset

Figure 28 Matching Parameters a and b of Pb, GOR and Bo, for fluid 1

Fluid 6

PVT - Correlation Parameters (fluid_6_tun_Pb+Pi_AL_6k.Out) (Oil - Black Oil matched)

Done Cancel Main Export Report Reset All Help

Bubble Point

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.94893	0.94196	1.03934	0.88621	0.92656	1.03291
Parameter 2	-177.191	-204.578	113.533	-459.159	-268.221	96.1169
Std Deviation						
	Reset	Reset	Reset	Reset	Reset	Reset

Solution GOR

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.01361	1.16972	0.89286	1.3617	1.5447	0.9171
Parameter 2	-11.6404	-8.0959	-1.2766e-16	-2.39751	-232.188	-2.00922
Std Deviation	0.057735				0.62892	0.058563
	Reset	Reset	Reset	Reset	Reset	Reset

Oil FVF

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.72099	0.57951	0.57982	0.70016	0.57636	0.65691
Parameter 2	0.27215	0.41427	0.41377	0.29637	0.41081	0.32112
Parameter 3	1	1	1	1	1	1
Parameter 4	1.38034	0.41326	0.41345	0.41343	0.10153	0.41318
Std Deviation						
	Reset	Reset	Reset	Reset	Reset	Reset

Oil Viscosity

	Beal et al	Beggs et al	Petrosky et al	Egbogah et al	Bergman-Sutton
Parameter 1	1.46351	0.43636	0.44768	-0.17357	1.4169
Parameter 2	0.018124	0.25719	0.22177	0.67473	0.15698
Std Deviation		0.002229	0.0024558		
	Reset	Reset	Reset	Reset	Reset

Figure 29 Matching Parameters a and b of Pb, GOR and Bo, for fluid 6

Fluid 4

PVT - Correlation Parameters (fluid_4_tun_Pb+Pi-VAS-6k.Out) (Oil - Black Oil matched)

Done | Cancel | Main | Export | Report | Reset All | Help

Bubble Point

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.9207	1.01151	1.03543	0.94217	0.98205	1.01778
Parameter 2	-195.962	23.3733	68.6955	-135.937	-38.6806	35.6471
Std Deviation						

Solution GOR

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.25361	0.98526	0.93938	1.14991	1.43612	0.95666
Parameter 2	-9.49561	-4.20064	-4.3593e-15	-1.96819	-132.477	-1.50634
Std Deviation	0.063311				0.57915	0.058023

Oil FVF

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.81525	1	1	0.74136	0.75268	0.7257
Parameter 2	0.17656	0	0	0.25324	0.2315	0.25514
Parameter 3	1	1	1	1	1	1
Parameter 4	0.21333	4.68986	4.68986	0.21281	0.30022	0.21234
Std Deviation						

Oil Viscosity

	Beal et al	Beggs et al	Petrosky et al	Egbogah et al	Bergman-Sutton
Parameter 1	2.61786	2.21247	1.3069	2.14779	5.24171
Parameter 2	-2.12362	0.77169	0.84619	-10.4551	-0.42284
Std Deviation	2.5495e-5			8.6313e-5	

Figure 30 Matching Parameters a and b of Pb, GOR and Bo, for fluid 4

Fluid 3

Bubble Point

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.94895	1.06226	1.10114	0.97359	0.94499	0.87456
Parameter 2	-114.298	111.134	168.77	-56.0319	-124.258	-336.981
Std Deviation						

Solution GOR

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.16093	0.88009	0.82464	1.06681	1.55137	1.50751
Parameter 2	-6.89645	-2.80444	-1.8781e-15	-1.39093	-93.6917	-2.01801
Std Deviation	0.059802				0.59669	0.082059

Oil FVF

	Glaso	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.34572	1.0087	1	0.81948	1.21572	0.98681
Parameter 2	-0.35236	-0.0084256	0	0.17624	-0.23246	0.01221
Parameter 3	1	1	1	1	1	1
Parameter 4	0.95405	0.95276	0.85109	0.95282	1.03542	0.95573
Std Deviation						

Oil Viscosity

	Beal et al	Beggs et al	Petrosky et al	Egbogah et al	Bergman-Sutton
Parameter 1	0.91122	0.75268	0.82669	12.1388	1.6075
Parameter 2	-1.30784	0.47858	-0.17331	-151.621	-0.42119
Std Deviation					

Figure 31 Matching Parameters a and b of Pb, GOR and Bo, for fluid 3

Differences in the oil and gas flow rate before and after tuning took place, using all the correlations tested

Fluid 1

Table 14 Liquid Flow rate results before and after tuning under a P_r = 5000 psi

Reservoir Pressure = 5000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δq_{oil}_bef-after**
Al-marhoun	9974,4	9730,8	243,6
Standing	10094,3	9628,8	465,5
Vasquez	10107,8	9649,8	458
Glaso	10078,8	9570	508,8

Table 15 Gas Flow rate results before and after tuning under a P_r = 5000 psi

Pressure = 5000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	6,473	6,301	0,172
Standing	6,551	6,234	0,317
Vasquez	6,56	6,25	0,31
Glaso	6,541	6,198	0,343

Table 16 Liquid Flow rate results before and after tuning under a P_r = 4000 psi

Reservoir Pressure = 4000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δ_{qoil}_bef-after**
Al-marhoun	6168,1	5868	300,1
Standing	6274,6	5703,3	571,3
Vasquez	6259,2	5740,5	518,7
Glaso	6222,7	5630,5	592,2

Table 17 Gas Flow rate results before and after tuning under a P_r = 4000 psi

Pressure = 4000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	4,003	3,802	0,201
Standing	4,072	3,699	0,373
Vasquez	4,062	3,725	0,337
Glaso	4,038	3,654	0,384

Table 18 Liquid Flow rate results before and after tuning under a P_r = 3375 psi

Reservoir Pressure = 3375 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δq_{oil}_bef-after**
Al-marhoun	3472,8	3083	389,8
Standing	3605,5	2857,7	747,8
Vasquez	3561,9	2908,4	653,5
Glaso	3525,1	2779,9	745,2

Table 19 Gas Flow rate results before and after tuning under a P_r = 3375 psi

Pressure = 3375 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	2,254	1,97	0,284
Standing	2,34	1,83	0,51
Vasquez	2,312	1,865	0,447
Glaso	2,288	1,786	0,502

Table 20 Liquid Flow rate results before and after tuning under a P_r = 3000 psi

Pressure =3000 psi		
Correlation	**q before (stb/day)**	**q after (stb/day)**
Al-marhoun	1156,3	dead well
Standing	1518,4	
Vasquez	1700,4	
Glaso	1596,5	

Table 21 Gas Flow rate results before and after tuning under a P_r = 3000 psi

Pressure = 3000 psi		
(MMscf/day)	**q_gas bef**	**q_gas after**
Al-marhoun	0,75045	dead well
Standing	0,98539	
Vasquez	1,104	
Glaso	1,036	

Fluid 6

Table 22 Liquid Flow rate results before and after tuning under a P_r = 6000 psi

Reservoir Pressure = 6000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δ_{qoil}_bef-after**
Al-marhoun	14656,6	14128	**528,6**
Standing	14715	13870	845
Vasquez	14698	13921	777
Glaso	14563,5	14102	461,5

Table 23 Gas Flow rate results before and after tuning under a P_r = 6000 psi

Pressure = 6000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	8,98	8,66	**0,32**
Standing	9,02	8,5	0,52
Vasquez	9	8,5	0,5
Glaso	8,93	8,6	0,33

Table 24 Percentage of the difference between the AOF before and after tuning

Pres (psi)	6000	5000	4000	3000
Correlation	**ΔAOF_aft-bef(*%)**			
Al-marhoun	**1,82**	**2,32**	**3,18**	**2,06**
Standing	-4,11	-5,31	-7,49	dead well
Vasquez	-9,72	-12,75	-17,72	
Glaso	-3,54	-4,56	-6,42	

Table 25 Liquid Flow rate results before and after tuning under a P_r = 5000 psi

Reservoir Pressure = 5000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δ_{qoil}_bef-after**
Al-marhoun	11182	10673,5	508,5
Standing	11251	10315	936
Vasquez	11255	10391	864
Glaso	11073	10645,5	427,5

Table 26 Gas Flow rate results before and after tuning under a P_r = 5000 psi

Reservoir Pressure = 5000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	6,85	6,54	0,31
Standing	6,9	6,3	0,6
Vasquez	6,9	6,37	0,53
Glaso	6,786	6,5	0,286

Table 27 Liquid Flow rate results before and after tuning under a P_r = 4000 psi

Reservoir Pressure = 4000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δq_{oil}_bef-after**
Al-marhoun	7532	7030	502
Standing	7571	6505	1066
Vasquez	7527	6646	881
Glaso	7377	6975,6	401,4

Table 28 Gas Flow rate results before and after tuning under a P_r = 4000 psi

Reservoir Pressure = 4000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	4,62	4,3	0,32
Standing	4,64	4	0,64
Vasquez	4,6	4,1	0,5
Glaso	4,52	4,27	0,25

Table 29 Liquid Flow rate results before and after tuning under a P_r = 3000 psi

Reservoir Pressure = 3000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δ_{qoil}_bef-after**
Al-marhoun	2965	1698	1267
Standing	2994	dead well	dead well
Vasquez	3134		
Glaso	2810	2192,7	617,3

Table 30 Gas Flow rate results before and after tuning under a P_r = 3000 psi

Reservoir Pressure = 3000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	1,82	1,04	0,78
Standing	1,83	dead well	dead well
Vasquez	1,9		
Glaso	1,72	1,34	0,38

Fluid 4

Table 31 Liquid Flow rate results before and after tuning under a P_r = 6000 psi

Reservoir Pressure = 6000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δ_{qoil}_bef-after**
Al-marhoun	13424	12517,5	906,5
Standing	13482	12995	487
Vasquez	13308,5	12613	695,5
Glaso	13314,7	12637	677,7

Table 32 Gas Flow rate results before and after tuning under a P_r = 6000 psi

Pressure = 6000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	8,23	7,7	0,53
Standing	8,26	7,9	0,36
Vasquez	8,156	7,7	0,456
Glaso	8,16	7,74	0,42

Table 33 Liquid Flow rate results before and after tuning under a P_r = 5000 psi

Reservoir Pressure = 5000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δ_{qoil}_bef-after**
Al-marhoun	9904	8928	976
Standing	9904	9387	517
Vasquez	9590	8958	632
Glaso	9601	9002	599

Table 34 Gas Flow rate results before and after tuning under a P_r = 5000 psi

Pressure = 5000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	6,07	5,5	0,57
Standing	6,07	5,75	0,32
Vasquez	5,88	5,5	0,38
Glaso	5,88	5,5	0,38

Table 35 Liquid Flow rate results before and after tuning under a P_r = 3000 psi

Reservoir Pressure = 3000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δ_{qoil}_bef-after**
Al-marhoun	1228	-	-
Standing	1388	899	489
Vasquez	1661	-	-
Glaso	1552,3	-	-

Table 36 Gas Flow rate results before and after tuning under a P_r = 3000 psi

Pressure = 3000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δ_{qgas}_bef_after**
Al-marhoun	0,75	-	-
Standing	0,85	0,55	0,3
Vasquez	1,02	-	-
Glaso	0,95	-	-

Fluid 3

Table 37 Liquid Flow rate results before and after tuning under a P_r = 6000 psi

Reservoir Pressure = 6000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δ_{qoil}_bef-after**
Al-marhoun	12531	13527	-996
Standing	13501,5	13546	-44,5
Vasquez	12896	13162	-266
Glaso	13014	13530	-516

Table 38 Gas Flow rate results before and after tuning under a P_r = 6000 psi

Pressure = 6000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	7,68	8,29	-0,61
Standing	8,275	8,3	-0,025
Vasquez	7,904	8,07	-0,166
Glaso	7,976	8,3	-0,324

Table 39 Liquid Flow rate results before and after tuning under a P_r = 5000 psi

Reservoir Pressure = 5000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δ_{qoil}_bef-after**
Al-marhoun	8714	9743	-1029
Standing	9791	9765	26
Vasquez	8993	9278	-285
Glaso	9164	9730	-566

Table 40 Gas Flow rate results before and after tuning under a P_r = 5000 psi

Reservoir Pressure = 5000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	5,34	5,97	-0,63
Standing	6	5,98	0,02
Vasquez	5,5	5,69	-0,19
Glaso	5,62	5,96	-0,34

Table 41 Liquid Flow rate results before and after tuning under a P_r = 4000 psi

Reservoir Pressure = 4000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δqoil_bef-after**
Al-marhoun	5765	5811	-46
Standing	5888	5848	40
Vasquez	5835,6	5865	-29,4
Glaso	5666	5856,4	-190,4

Table 42 Gas Flow rate results before and after tuning under a P_r = 4000 psi

Reservoir Pressure = 4000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	3,5	3,56	-0,06
Standing	3,565	3,58	-0,015
Vasquez	3,58	3,6	-0,02
Glaso	3,47	3,6	-0,13

Table 43 Liquid Flow rate results before and after tuning under a P_r = 3000 psi

Reservoir Pressure = 3000 psi			
Correlation	**q before (stb/day)**	**q after (stb/day)**	**Δqoil_bef-after**
Al-marhoun	2434	2324	110
Standing	2154,5	2397	-242,5
Vasquez	2477,5	2372	105,5
Glaso	2259	2371	-112

Table 44 Gas Flow rate results before and after tuning under a P_r = 3000 psi

Reservoir Pressure = 3000 psi			
(MMscf/day)	**q_gas bef**	**q_gas after**	**Δqgas_bef_after**
Al-marhoun	1,5	1,42	0,08
Standing	1,32	1,47	-0,15
Vasquez	1,52	1,45	0,07
Glaso	1,39	1,45	-0,06

Table 45 Percentage of the difference between the AOF before and after tuning

P_{res} (psi)	6000	5000	4000	3000
Correlation	$\Delta_{AOF\_aft\text{-}bef}$(*%)			
Al-marhoun	6,2	7,9	10,7	16,6
Standing	1,9	2,4	3,1	4,5

Vasquez	1	1,2	1,6	2,4
Glaso	2	2,5	3,4	5,1

Depth at which bubble point occurs

Fluid 6

Table 46 Bottom Measured Depth at which bubble point occurs

Pressure (psi)	6000		5000		4000		3000	
	MD (ft) where Pb occurs							
Tuning State	before	after	before	after	before	after	before	after
Al-Marhoun	6733	7217	7700	7925	8600	8825	8825	8600
Standing	8150	6733	9050	7458	already below Pb	7925	already below Pb	already below Pb
Vasquez	already below Pb	6492	already below Pb	7217		7925		
Glaso	7925	6975	9050	7700		8375		8600

Fluid 3

Table 47 Bottom Measured Depth at which bubble point occurs

Pressure (psi)	6000		5000		4000		3000	
	MD (ft) where Pb occurs							
Tuning State	before	after	before	after	before	after	before	after
Al-Marhoun	already below Pb		already below Pb		already below Pb		already below Pb	
Standing								
Vasquez								
Glaso								