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**COMPOSITIONAL GRADIENT CALCULATIONS FOR A
SAUDI ARABIAN GAS CONDENSATE RESERVOIR**

BY

KHALED OTHMAN AL-SUBAI

A Thesis Presented to the
DEANSHIP OF GRADUATE STUDIES

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS

DHAHRAN, SAUDI ARABIA

In Partial Fulfillment of the
Requirements for the Degree of

MASTER OF SCIENCE

In

PETROLEUM ENGINEERING

January 2001

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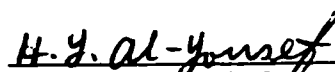
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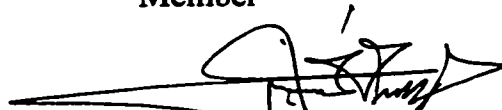
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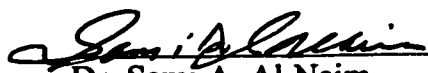
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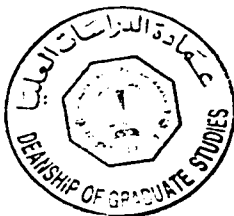
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ملخص الرسالة

اسم الطالب : خالد بن عثمان السبيعي
عنوان الرسالة : حسابات التغير في المكونات لمكثفات الغاز لمكمن سعودي
التخصص : هندسة بترول
تاريخ التخرج : يناير ٢٠٠١ م

إن التغير في المكونات مع العمق في مكامن الغاز و الزيت قد لوحظ من قبل المتخصصين . وهذا التغير في عدة حالات كان بسبب قوى الجاذبية . فيكون تركيز العناصر الخفيفة أكثر في أعلى المكمن بينما يكون تركيز العناصر الثقيلة أكثر في أسفل المكمن .

وقد قام عدة باحثين باقتراح عمليات حسابية لحساب مثل هذا التغير . وقد استخدمت هذه الحسابات كأداة لفهم مدى ترابط أجزاء المكامن و تحديد عمق نقطة تلاقي الغاز والزيت في المكمن .

وفي هذه الدراسة ، استخدمت حسابات تغير المكونات مع العمق لدراسة مكمن لمكثفات الغاز من أجل معرفة مدى اتصال أجزاء المكمن وإمكانية وجود نقطة تلاقي الغاز مع الزيت .

وقد خلصت الرسالة إلى أن أجزاء المكمن غير متصلة وأنه لا يوجد نقطة تلاقي بين الغاز و الزيت . وهذه النتيجة قد دعمت بالمعلومات الجيولوجية المتوفرة والمسح الزلزالي الذي أظهر وجود تصدعات في المنطقة المعنية . والنتيجة التي خلصت إليها الدراسة مهمة جدا لتطوير مثل هذا المكمن وخاصة عند الحاجة لمشروع إعادة حقن الغاز لزيادة نسبة إنتاج واستخلاص المكثفات .

درجة الماجستير في العلوم
جامعة الملك فهد للبترول والمعادن
الظهران – المملكة العربية السعودية
يناير ٢٠٠١ م

Thesis Abstract

Full Name of Student: Khaled Othman Al-Subai
Title of Study: Compositional Gradient Calculations for a Saudi Arabian Gas Condensate Reservoir

Major Field: Petroleum Engineering
Date of Degree: January 2001

The variation in the composition with the depth in hydrocarbon reservoirs has been observed by technologists in oil industry. This variation, in several cases, was a result of gravity forces. The concentration of the lighter components tend to be more towards the top of the reservoir and the concentration of the heavier components tend to be more towards the bottom of the reservoir. Several authors suggested some algorithms to predict this variation. These algorithms were used as a tool to investigate reservoir continuity and determine the gas-oil contact (GOC) depth.

In this study, the technique of compositional gradient calculations is used in a real field data for one of the Saudi gas-condensate reservoirs to address the reservoir continuity and investigate the possibility of having a GOC in the reservoir. The study showed that the reservoir is not continuous and there is no GOC in the reservoir. Also the results were supported by reservoir geology 3-D seismic that showed faults in the area of interest. The findings of this study are essential for the development of such reservoir since a gas-cycling project will be needed to maximize the condensate recovery.

**MASTER OF SCIENCE DEGREE
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CHAPTER 1

INTRODUCTION

Variations in gas composition along the hydrocarbon column, that are continuous through significant ranges in elevation, have been noted by petroleum technologists. The mole fractions of the lighter hydrocarbons decrease, whereas the heavy fractions increase from the top to the bottom of the reservoir. These variations may affect reservoir fluid properties considerably.

This variation in the composition with depth was explained, in many reservoirs, as a result of gravity forces inducing and stabilizing the compositional differences. Several authors have tried to predict the changes induced by such forces. Several algorithms to solve such phenomena have been suggested. The theoretical background and the method of calculation of such algorithms are discussed in chapter 4.

The proposed algorithms have been used as a tool to investigate the reservoir continuity. This tool indicates the reservoir discontinuity, when the observed compositional variation is significantly different from the calculated composition from the proposed algorithms. These algorithms have also been used in locating gas-oil contacts (GOC) in hydrocarbon reservoirs. As illustrated in Figure 1.1, the GOC can be determined by calculating the saturation pressure of the hydrocarbon fluids as the composition changes. When the GOC is reached, a sharp decrease in the saturation pressure will be seen as a result of phase change from gas to liquid.

Ignoring the variation in the composition of condensate reservoirs could lead to significant errors in hydrocarbon volumes in place. Wheaton et al. (Wheaton, 1991 [16]) have reported up to 20% error in reserve estimates in reservoirs that show modest changes in composition. Unfortunately, these types of calculations need a compositional numerical simulation.

The hydrocarbon reserves will also be in error if the reservoir is underlined by an oil-rim that is not encountered in any location. In such a case, the pore volume occupied by the oil is most probably considered to be gas filled. The compositional gradient technique is very helpful in such reservoirs to investigate the possibility of GOC presence.

Usually, in gas condensate reservoirs, the production strategy includes a gas cycling to recover all gas and liquid reserves. Reservoir continuity is an important factor for the success of any gas cycling project.

In this study one of the commercial PVT programs (see Appendix A) was used to perform a compositional gradient variation calculations to a real Saudi gas condensate reservoir that experienced a compositional variation with depth.

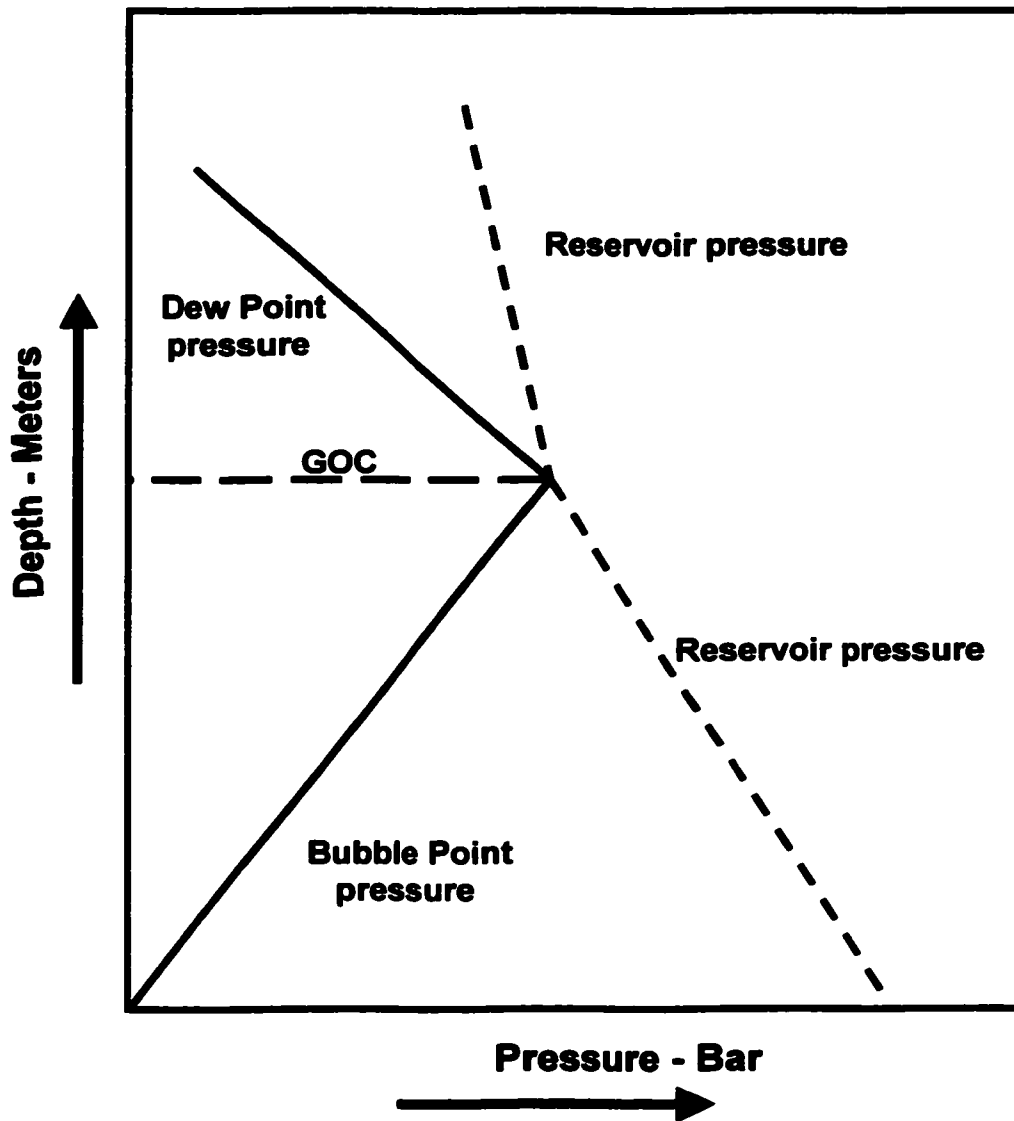


Figure 1.1: Bubble-point Pressure of Oil, Dew-point Pressure of Cap Gas and Reservoir Pressure vs. Depth, (Schulte 1980, [13])

CHAPTER 2

LITERATURE REVIEW

Equations of state (EOS) are, for pure substances, mathematical relations between volume, pressure, and temperature. For mixtures, EOS in addition includes composition. EOS are very versatile tools for engineering applications. They can be used for all states of matter (mostly gas, vapor, and liquid), and they can describe transitions between states (*Pedersen 1989 [9]*).

The objective of developing the EOS has been to find an equation of a form such that it can be made to fit data for any material by assignment of proper

values to the constants that appear in the equation. No equation has yet been found which wholly satisfies this objective.

However, equations have been developed which are adequate for many engineering purposes (*Smith 1975 [15]*).

There are many types of equations of state and they can be classified into four families:

1. Van der Waals family
2. Benedict-Webb-Rubin family
3. Reference-fluid equations
4. Augmented-rigid-body equations

The first family encompasses simple, mostly cubic EOS. Their main characteristic is the separation between the repulsive and attractive effects. Despite their simplicity, these EOS display quantitatively correct performance, even being able to describe multiphase equilibria, critical points, and other complicated phenomena (*Pedersen 1989 [9]*).

The **first family** is more commonly used than the others because of the following reasons (*Pedersen 1989 [9]*):

1. A cubic EOS of this family yield relatively simple expressions for the thermodynamic properties and phase equilibrium relationships of interest.

2. The EOS of the other families, though more complicated in nature, do not give quantitatively better descriptions of mixture phase transitions than cubic EOS.

Whitson presented several methods for calculating the one-dimensional vertical variation in the composition with depth caused by gravity and thermal gradients. The Peng-Robinson (PR) and Soave-Redlich-Kwong (SRK) cubic equations of state were used as thermodynamic models. A solution algorithm was suggested for solving the isothermal gravity/chemical equilibrium (GCE) problem. The algorithm is simply an adaptation of a method proposed by Michelsen for calculating saturation pressure (*Whitson 1994 [17]*).

The author emphasized on the importance of developing a comprehensive and consistent fluid characterization before making gradient calculations. Then he recommended a procedure for developing an EOS fluid characterization of a reservoir with a compositional variation based on obtaining a match of measured PVT data for several fluid samples that cover the entire range of compositions, which have been sampled from the reservoir (*Whitson 1994 [17]*).

The formulation for calculating compositional variations under the force of gravity for an isothermal system was first given by Gibbs. The condition of equilibrium is satisfied by the constraint

$$F_k(p^0, z^0, T) = F_k(p, z, T) + M_k g(h - h^0) \quad (2.1)$$

In the above equation, F_k is the chemical potential of component k , z^0 is a homogeneous (single-phase) mixture at pressure p^0 at a reference depth h^0 , “ p ” is the pressure and “ z ” is the mixture composition at depth “ h ” (Whitson 1994 [17]).

Sage et al. (Sage 1938 [12]) evaluated equation 2.1 assuming an ideal solution behavior and indicated that a knowledge of the molal volume, molecular weight of the phase and the partial molal volume of the component, is sufficient to permit the calculation of the change in mole fraction of the component with elevation. They also provided examples showing significant variation of the composition with the depth for reservoir mixtures.

They emphasized that the magnitude of the gravitational effects is related to the differences between the molal volume of the system and the partial molal volume of the component in question. Furthermore, they made the key observation that systems in the vicinity of a critical condition should be expected to have significant compositional variations. They also mentioned that as more experimental information accumulates, it would be possible to predict the

gradients for naturally occurring hydrocarbon liquids without assuming an ideal solution behavior (*Sage 1938 [12]*).

Montel et al. (*Montel 1985 [7]*) presented another method of predicting fluid compositional grading with depth. It was designed to enable numerical simulations of this phenomenon. The method only takes into account the gravitational effect; it enables the calculations of the phase behavior of a fluid everywhere in a column, assuming that the stationary state has been reached. They stated that the larger the reservoir thickness and the differences between molecular weight of components, the more the influence of gravitational forces on compositional grading.

The proposed algorithm is an iterative calculations based on the fugacities of each component at different depths. The procedure is only approximate because it calculates the pressure using an incremental hydrostatic term instead of solving for pressure directly (*Montel 1985 [7]*).

Schulte (*Schulte 1980 [7]*) illustrated that a significant compositional variation can result from a gravity segregation in petroleum reservoirs. He stated that the gravity forces are operative in a gas column and influence the composition of the gas.

He also made the statement that the introduction of binary interaction coefficients (used in the mixing rules of a cubic EOS) in the equation of state are seen to have strong influence on the prediction of the gravity segregation. He investigated the effect of the use of different equation of state and found that the Soave equation and Peng-Robinson equation yield similar results (*Schulte 1980 [13]*).

Faissat, B., et al (*Faissat 1994 [4]*) discussed the phenomenon of thermal diffusion and its effect on gas composition. They studied several formulations that clearly showed, at stationary state, the variation of the gas composition with depth is controlled by 2 external constraints: the gravity and the temperature gradient. Moreover, they showed that the presence of capillary forces play an important role in the phenomenon, which suggests that the characteristics of the porous medium must be taken into account in the description of a real thermal diffusion.

Some examples of gradient calculations are present in the literature. Montel and Gouel presented an example that clearly shows that the gravitational segregation alone can largely influence the compositional grading observed in the reservoir. Finally the authors suggested that including thermal diffusion might improve the reliability of the calculated compositional gradients (*Montel 1985 [7]*).

A Second example was presented by Holt et al. (Holt 1983 [6]). They presented a formulation of a compositional gradient problem including a thermal diffusion. The results of their study showed that neither of the two effects could explain the observed variation in the composition in the field under study.

Riemens et al. (Riemens 1983 [11]) presented a third example. They presented an evaluation of the compositional grading in the Birba Field, Oman. It was shown, based on gravity/chemical equilibrium (GCE) calculations and PVT data, that significant compositional gradient exists.

Wheaton showed that neglecting the compositional gradient in a gas condensate reservoirs may results in errors of up to 20% in estimating the initial hydrocarbon in place, even in fields showing a modest changes in composition with depth. It will also give rise to substantial errors in predicted oil recovery from condensate fields (Wheaton 1991 [16]).

The author stated that two factors cause the compositional gradients to be larger than normal. The *first* is the presence of small amounts of very heavy hydrocarbons and particularly aromatic components in the gas or the oil. The *second* is the presence of a large "middle fraction" (C₂ through C₄), which normally puts a mixture near its critical composition (Wheaton 1991 [16]).

Chaback commented on Wheaton's study stating that non-isothermal effects can be of the same order of magnitude as gravity effects. More importantly, he noted the fact that a non-isothermal system will never reach equilibrium (zero energy), even though a stationary (steady-state) condition of zero net mass flux is reached (*Chaback 1992 [1]*).

Shtepani et al. (*Shtepani 1996 [14]*) presented a new modification to the cubic EOS that will improve its prediction capability in the gas condensate phase behavior. The modification is simply a general correction of the EOS attraction parameter "a" by which, "a" coincidence of SRK-EOS and PR-EOS-based predictions with the laboratory data could be satisfactorily improved. The authors made the statement that phase behavior prediction of a gas condensate system is generally poor. Furthermore, they stated that this lack of prediction accuracy is attributable to the significant fraction of low-molecular-weight components.

Padua, in a recent study (*Padua 1999, [8]*), examined the oil composition distribution of a large deep-water field where the temperature variation is in the opposite direction of the Earth's thermal gradient. His main objective was to investigate if the oil distribution would suggest fluid connectivity in the subject reservoir. He used several methods. One of them is the compositional gradient calculation method. The mathematical formulation used in his study follows Gibbs' where the capillary forces were neglected. The fugacity was calculated

by using the cubic equation of state proposed by Peng Robinson with binary interaction coefficients.

The whole process used in his study was an iterative process that relies on the satisfactory agreement of real and theoretical data observed on a single pre adjusted equation of state of the samples of the wells considered. He stated in his study that a satisfactory agreement between predicted and observed oil composition leads to the conclusion of reservoir connectivity. He also made the conclusion that the fluid characterization performed by means of a single Peng-Robinson equation of state model is capable of accurately reproducing the wide range of experimental data available. The results presented in his study suggest a progressive decrease in the mole fraction of the light components with increasing depth, accompanied by a corresponding increase in the amount of the heavier components making up the system.

Naturally occurring reservoir fluids typically consist of pure, well-defined components including CO₂, N₂, C₁, C₂, C₃, iC₄, nC₄, iC₅, nC₅, C₆ and many hundreds of heptanes and heavier components (C₇₊). It is not possible to isolate all of the C₇₊ compounds, or to assign accurate physical properties to each of them. Because of computational limitations the total number of components used to describe reservoir fluids with an equation of state seldom exceeds 10 to 15, where only a few of these components represent the C₇₊

fraction. Therefore, one of the objectives of C₇₊ characterization is to obtain the best possible description of these many hundreds of undefined compounds using a minimum number of “pseudo components” (Whitson 1989 [18]).

Whitson et al. (Whitson 1989 [18]) presented a study that deals with the problem of defining the properties and mole fractions of a finite number of C₇₊ pseudo components to best approximate a continuous representation of the C₇₊ molar distribution. A modified Gaussian quadrature method is used to treat the continuous molar distribution discretely.

Pedersen, K.S. et al. (Pedersen 1989 [10]) presented an experimental data from the North Sea. In their work they showed that SRK-EOS coupled with a simple C₇₊ characterization procedure has proved to provide accurate results for the phase behavior of reservoir fluids.

CHAPTER 3

STATEMENT OF THE PROBLEM AND STUDY OBJECTIVE

A new gas condensate reservoir in Saudi Arabia is currently under development. For this reservoir, reported PVT data showed a wide range of variation in dew point pressure and condensate yield, both with depth and location. The condensate gas ratio (CGR) values reported in the field range from 40 to 280 bbl/MMSCF as shown in Figure 3.1. The dew point pressure is

also ranging between 4500 psig and 5970 psig (Figure 3.2). Currently the reservoir pressure is approximately 3500 psig higher than the average dew point pressure. The variation in the gas composition reported by the PVT data, for the reservoir under study, is explained by a possible gravity segregation of different gas molecules.

The magnitude of the variation is very large. It is possible that such magnitude of a variation can not be present in such reservoir as a result of gravity segregation alone. In such a case, the possibility of having the reservoir being discontinuous does exist which can explain the variation.

Therefore, the objective of this study is to perform compositional gradient calculations induced by gravity forces for this reservoir, that may verify the possibility of having such variations in the composition as a result of gravity induced gradients. In addition, this study will use the gradient calculation technique to address the reservoir continuity.

A production strategy that includes gas cycling for this type of reservoir is essential to recover all gas and liquid reserves by extracting the condensate during the reservoir production life. The reservoir continuity is an important factor for the success of any gas cycling project. Gravity gradient is believed to be helpful to investigate whether the reservoir is in communication or not.

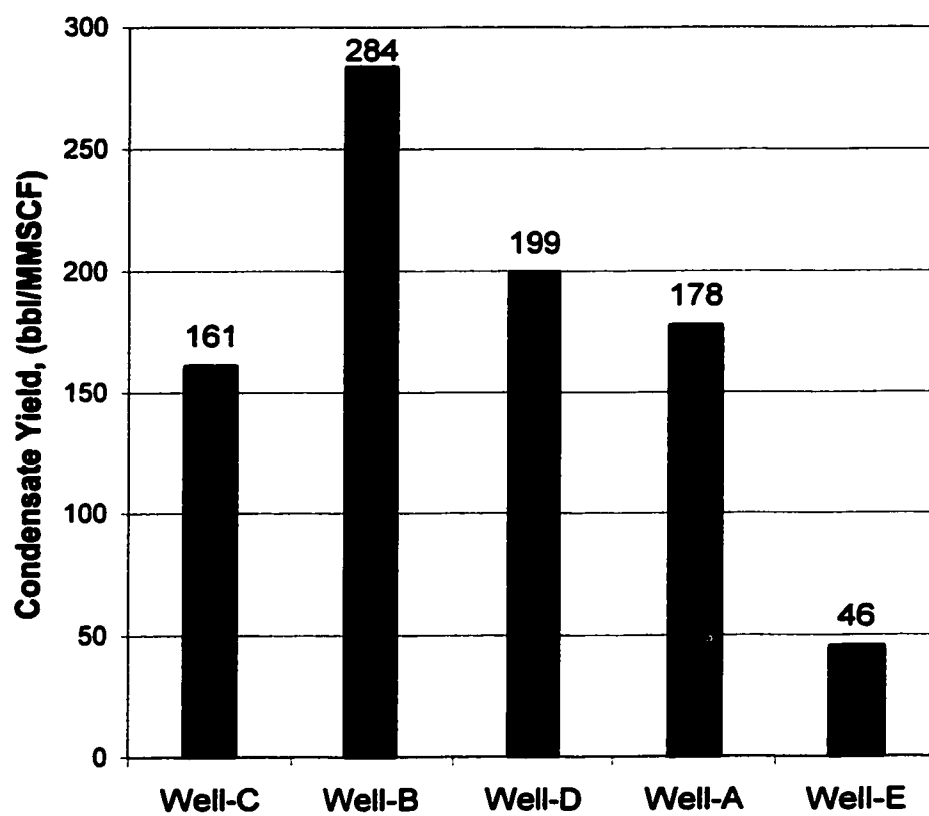


Figure 3.1: Condensate Yield Comparison Plot

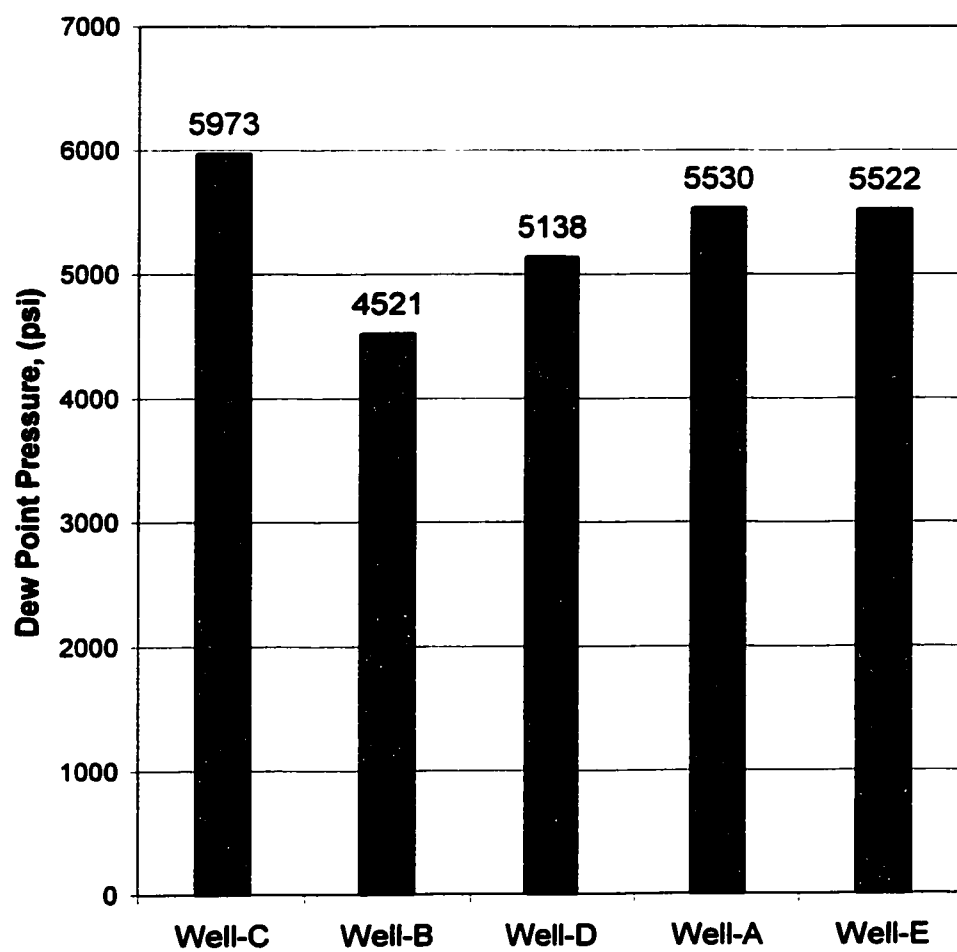


Figure 3.2: Dew Point Comparison Plot

CHAPTER 4

CALCULATION METHOD AND THEORY

In this chapter the theory behind the method and the method of calculation involved in a compositional gradient prediction are discussed.

4.1 Theory behind the Method

This section will discuss the theoretical background of the method used to perform the gravity gradient calculations in hydrocarbon reservoirs as presented by Sage (*Sage 1938 [12]*).

In the engineering work it is customary to consider the pressure, the temperature and the composition of a phase to be the independent variables sufficient to establish its state. This procedure neglects the effect of gravitational fields upon the energy associated with the system and assumes, among other things, that the pressure is uniform in all parts of the system. If it is desired to introduce the effect of gravity, it becomes necessary to change the constant in the phase rule from 2 to 3, and the rule may then be stated by the following equation:

$$f_d = c - p + 3 \quad (4.1)$$

Where : f_d = Degree of freedom

C = Number of components

P = Number of phases

Under these circumstances it is seen that the stipulation of $n+2$ variables is required to define the state of a one-phase n -component system. In the present discussion, these will be assumed to be the pressure, the temperature, the mole fractions of $n-1$ components and the elevation (above some arbitrarily chosen datum) in a continuous column of fluid, subjected to a uniform gravitational field.

The values of all these variables must be related to a given point in the column of fluid.

For a system to be at equilibrium under such conditions, it is necessary that the chemical potential (i.e., the partial molal free energy) of each component be equal at all points in the system. This fact may be expressed in the following way:

$$d\bar{F}_k = 0 \quad (4.2)$$

Since the chemical potential is a function of state, the assumption as to the independent variable makes it a function of the pressure, temperature, elevation and weight fractions of n-1 components. The following equation, based only upon the fundamental relationship of partial differentiation, may then be written for isothermal conditions:

$$d\bar{F}_k = \left(\frac{\partial \bar{F}_k}{\partial P} \right)_{T,h,n_s} dp + \left(\frac{\partial \bar{F}_k}{\partial h} \right)_{T,p,n_s} dh + \left(\frac{\partial \bar{F}_k}{\partial n_k} \right)_{T,p,h,n_m} dn_k + \sum_{j=1}^{j=n-1} \left(\frac{\partial \bar{F}_k}{\partial n_j} \right)_{T,p,h,n_s} dn_j \quad (4.3)$$

From equations 2 and 3, the change in the composition that is necessary to compensate for the corresponding changes in the chemical potential with pressure and elevation under isothermal conditions may be evaluated. However, it is necessary to determine the change in the chemical potential with

respect to the pressure and the elevation in terms of the measurable quantities before the quantitative values of $\left(\frac{\partial n_k}{\partial h}\right)_T$ may be obtained. The chemical potential may be defined partly by means of the relationship:

$$\overline{F}_k = \overline{E}_k - T\overline{S}_k + P\overline{V}_k \quad (4.4)$$

If this is differentiated for a constant temperature, the following equation is obtained:

$$d\overline{F}_k = d\overline{E}_k - Td\overline{S}_k + Pd\overline{V}_k + \overline{V}_k dP \quad (4.5)$$

From the laws of thermodynamics, a general expression may be written for a reversible change in state at a constant pressure and temperature:

$$Td\overline{S}_k = d\overline{E}_k + Pd\overline{V}_k + \omega' \quad (4.6)$$

In equation 4.6 the term ω' is any work done by the system (in this case, the component) exclusive of that resulting from its change in volume, which is accounted for by the term $Pd\overline{V}_k$. If equations 5 and 6 are combined, a relationship is obtained between the change in the chemical potential and the change in pressure and work done by the system:

$$d\bar{F}_k = \bar{V}_k dP - \omega' \quad (4.7)$$

If equation 4.7 is restricted to changes in state occurring under isobaric, isothermal conditions, a relationship between the change in the chemical potential and the work done other than by volume change is obtained:

$$d\bar{F}_k = -\omega' \quad (4.8)$$

The work ω' that is involved in changing the elevation of a mole of component k at a constant pressure and temperature is indicated by the following expression:

$$-\omega' = M_k dh \quad (4.9)$$

The rate of change of the chemical potential with the elevation is related to the molecular weight of the component in the following way:

$$\left(\frac{\partial \bar{F}_k}{\partial h} \right)_{T,P,n_a} = M_k \quad (4.10)$$

The change in the chemical potential with pressure is related to the partial molal volume of the component by means of the following general thermodynamic

expression, which follows from equation 4.7, since, in the present discussion, ω is equal to zero when h is constant:

$$\left(\frac{\partial \bar{F}_k}{\partial P} \right)_{T, h, n_a} = \bar{V}_k \quad (4.11)$$

The change in the pressure with respect to the elevation may be ascertained from a knowledge of the molecular weight and the molal volume of the phase as a whole. This relationship is indicated in the following equation for a phase acted upon by a standard uniform gravitational field:

$$\frac{dP}{dh} = - \frac{M}{V} \quad (4.12)$$

If the foregoing expressions are combined with equations 2 and 3, a relationship between the isothermal change in the composition with the elevation and the measurable properties of the phase is obtained:

$$\left(\frac{\partial n_k}{\partial h}\right)_T = \frac{\frac{M\bar{V}_k}{V} - M_k - \sum_{j=1}^{j=n-1} \left(\frac{\partial \bar{F}_k}{\partial n_j}\right)_{T,P,h,n_q} \frac{dn_j}{dh}}{\left(\frac{\partial \bar{F}_k}{\partial n_k}\right)_{T,P,h,n_m}} \quad (4.13)$$

The solution of equation 4.13 requires a knowledge of the change in the chemical potential with the composition. This necessitates a reasonable amount of information concerning the behavior of the system before it is possible to solve equation 4.13 without simplifying assumptions.

The chemical potential of a component may be evaluated by means of the following expression, in which F_k^* is the thermodynamic potential of the component in the pure state and at an infinite attenuation, corresponding to pressure P_0 . This equation is based upon the assumption of ideal solutions at an infinite attenuation, which appears to be adequately justified by the kinetic theory for nearly all systems:

$$\bar{F}_k = RT \ln n_k + \int_{P_0}^P \bar{V}_k dP + F_k^* \quad (4.14)$$

If equation 4.14 is differentiated with respect to the mole fraction of a component k at a constant temperature and pressure, the following relationship is obtained:

$$\left(\frac{\partial \bar{F}_k}{\partial n_k} \right)_{T,P,h,n_m} = \frac{RT}{n_k} + \int_{P_0}^P \left(\frac{\partial \bar{V}_k}{\partial n_k} \right)_{T,P,h,n_m} dP \quad (4.15)$$

If equation 4.15 is combined with equation 4.13, the following relationship between the composition and the elevation in a uniform gravitational field of the standard intensity is obtained:

$$\left(\frac{\partial n_k}{\partial h} \right)_T = \frac{\frac{M\bar{V}_k}{V} - M_k - \sum_{j=1}^{j=n-1} \left(\frac{\partial \bar{F}_k}{\partial n_j} \right)_{T,P,h,n_j} \frac{dn_j}{dh}}{\frac{RT}{n_k} + \int_{P_0}^P \left(\frac{\partial \bar{V}_k}{\partial n_k} \right)_{T,P,h,n_m} dP} \quad (4.16)$$

If it is assumed that the system in question follows the behavior of an ideal solution at all pressures for the temperature in question, equation 4.16 reduces to the following relationship. Since the chemical potential of a component is then independent of the nature and relative proportions of the other components present and the partial molal volume of a component is independent of its mole fraction.

$$\left(\frac{\partial n_k}{\partial h}\right)_T = \frac{n_k}{RT} \left(\frac{M\bar{V}_k}{V} - M_k\right) \quad (4.17)$$

4.2 Method of Calculation

The method of predicting the fluid compositional grading with depth is an iterative calculations based on the fugacities of each component at different depths with the assumption that the stationary state of each component has been reached. These fugacities are functions of the temperature, the pressure and the composition, hence they can be calculated directly from the equation of state.

The formulation for calculating compositional variation under the gravity force for an isothermal system is given by equation 4.18.

$$F_k(p^0, z^0, T) = F_k(p, z, T) + M_k g(h - h^0) \quad (4.18)$$

For a given component in the system, the condition of equilibrium for the system is satisfied by the constraint that the sum of the chemical potential and

the gravity potential should be constant. This condition represents N equations, where N is the number of components.

$$\sum_{k=1}^N z_k(h) = 1 \quad (4.19)$$

Together with the constraint that the sum of mole fractions at any depth $Z(h)$ must add to one, it is possible to solve for composition $Z(h)$ and pressure $p(h)$ at a specified depth h .

Equation 4.18 when expressed in terms of fugacity becomes,

$$f_k(h) = f_k(h^0) \exp\left[-\frac{M_k g(h - h^0)}{RT}\right] \quad (4.20)$$

The local equilibria at $h=h_2$ and $h=h_1$ can directly be related. The differences in chemical potentials can be obtained by using an equation of state. If the mole fractions x_1, x_2, \dots, x_{n-1} ($\sum x_i=1$) and the pressure p for the fluid are given at $h=h_1$, the fluid variables at $h=h_2$ can be obtained by solving the N equations. Starting from a certain composition and pressure at datum level $h=0$, one can calculate composition and pressure for positive and negative values of h . *Figure 4.1* is a flowchart showing the calculation steps involved in performing gravity induced gradient calculations.

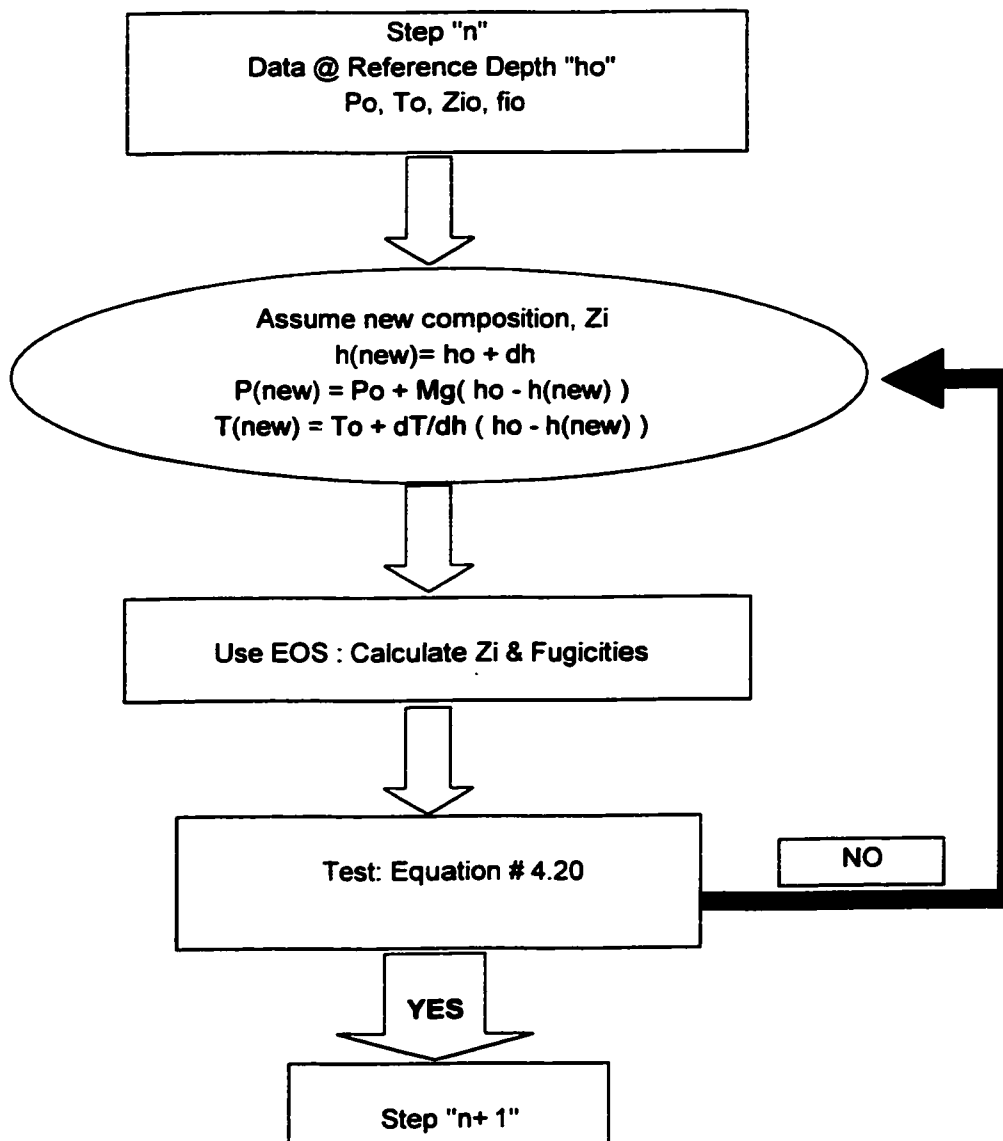


Figure 4.1: Compositional Gradient Calculation Flow Chart

CHAPTER 5

RESULTS AND DISCUSSION

In this chapter, the methodology used in this study will be stated first followed by five sections. The first section presents and discusses the available data used in this study. The second section covers the validation of the data. The third section covers PVT data matching. The fourth section covers the compositional gradient calculations performed in this study. The final section discusses the results of this study. It also presents about the available geological data and tries to support the findings with the available geological information.

5.1 Methodology

The methodology used in this study is similar to the procedure suggested by Whitson in his study titled *"Compositional Gradients in Petroleum Reservoirs"*, (Whitson 1994 [17]). First all PVT and test data were collected. Second, the validity of the data was verified for the consistency. Third, the sampling procedure for all samples was checked to assure proper sampling practices. After all data is verified, an equation of state (EOS) was tuned for each sample using the Peng-Rebanson (PR) cubic equation of state. The PVT package from Petroleum Expert (see Appendix-A) was used to perform the calculations. After that, the compositional gradient calculations were performed on all samples using the tuned EOS to see the expected change in the gradient with depth. Finally, the results were analyzed and checked if can be supported by reservoir geology.

5.2 Available Data

Five wellhead samples were available from the reservoir under study. These samples are from five different wells covering a depth range of more than 2000 feet. These samples are recombined wellhead samples based on the gas oil ratio (GOR) of the separator during the test. The sampling information for all samples is shown in Table 5.1. The laboratory measured gas composition of the

samples is shown in Table 5.2. Figure 5.1 is a bar chart comparing the composition of all the samples. PVT reports for all samples are also available and some geological and seismic data for the area.

5.3 Validation of Data

The sampling procedures for all samples were all checked and found to be properly sampled based on the following:

- The gas flow-rate and condensate rates were very stable when the samples were taken (see Tables 5.4, 5.5, 5.6, 5.7 & 5.8 for original field flow test data)
- The gas flow-rate was also high and believed to be adequate to lift any liquids that might dropout in the well bore.
- The flowing bottom-hole pressure during sampling was above the dew point pressure (see Table 5.3).

Figures 5.2 to 5.6 are plots of $\log(k_i * P_s)$ vs. Hoffman Factor to check the consistency of the lab data (see Appendix C for the theory of this method).

$$HoffmanFactor = \frac{(\log_{10}(p_{c,i}) - \log_{10}(p_{ref})) \left(\frac{1}{T_{b,i}} - \frac{1}{T_{sep}} \right)}{\left(\frac{1}{T_{b,i}} - \frac{1}{T_{c,i}} \right)}$$

These plots suggested that all samples are good with the exception of Well-E, which shows a large deviation from the straight-line trend. When flow meter and geological data were reviewed, Well-E sample was found to be suspicious. The upper section of the reservoir was missing in the area of Well-E and the gas could have been coming from the reservoir under study and the one above it. This sample was then excluded from the analysis.

Table 5.1: Sampling Information

	<i>Well-A</i>	<i>Well-B</i>	<i>Well-C</i>	<i>Well-D</i>	<i>Well-E</i>
GAS (MMSCFD)	19.98	18.121	4.2	9.69	16.17
Condensate (BPD)	3553	5143	677	1931	737
Depth (ft.)	14002	14567	14722	14438	12899
Condensate (BBL/MMSCF)	178	284	161	199	46
BHTEMP	298	305	305	301	283
SBHP	8973	8505	8800	8790	8600
FWHP	4038	2924	4480	4905	5978
F_TEMP*	212	214	138	173	150
Seprator Pressure	1030	330	270	578	536
SepratorTemp.	177	155	66	125	70
Seprator GOR, SCF/Sep. bbl	5623	3525	6206	5018	21940

* Flowing Wellhead Temperature

Table 5.2: Gas Composition of Tested Wells

Component	Well-A	Well-B	Well-C	Well-D	Well-E
Nitrogen	3.07	3.45	3.12	3.49	3.45
Carbon Dioxide	2.92	2.73	3.23	2.7	2.79
Hydrogen Sulfide	0	0	0	0	0
Methane	68.77	57.71	69.76	65.07	77.98
Ethane	9.77	10.72	9.03	10.5	8.84
Propane	4.09	5.99	4.02	4.97	2.88
iso-Butane	0.71	1.06	0.81	0.95	0.56
n-Butane	1.52	2.39	1.44	1.87	0.75
iso-Pentane	0.57	0.87	0.6	0.77	0.31
n-Pentane	0.62	0.97	0.55	0.78	0.21
Hexanes	0.9	1.72	0.96	1.25	0.32
Heptanes	1.08	2.38	1.11	1.49	0.34
Octanes	1.3	2.32	1.27	1.56	0.38
Nonanes	0.92	1.34	0.86	1.08	0.28
Decanes	0.68	0.83	0.61	0.78	0.19
Undecanes	0.38	0.36	0.29	0.38	0.13
Dodecanes plus	2.7	5.16	2.34	2.36	0.59

100%**100%****100%****100%****100%**

**Table 5.3: Dew Point and Flowing Bottom-hole Pressure
Data, (psig)**

	<i>Dew Point</i>	<i>FBHP</i>	<i>Delta (FBHP - Dew Point)</i>
<i>Well-A</i>	5530	8115	2585
<i>Well-B</i>	4521	7200	2679
<i>Well-C</i>	5973	6795	822
<i>Well-D</i>	5138	7600	2462
<i>Well-E</i>	5522	8485	2963

Table 5.4: Flow Test Data Well-A

Time	Duration (HOURS)	Condensate Rate (BPD)	Gas Rate (MMSCFD)	CGR (BBL/MMSCF)	Fwhp (PSIG)
8:30	0:00	-	21.90		3990
9:00	0:30	3059	19.10	160	3950
9:30	1:00	3129	19.60	160	3950
10:00	1:30	3027	19.60	154	4000
10:30	2:00	3051	19.90	153	4025
11:00	2:30	3200	20.60	155	4175
11:30	3:00	3152	20.10	157	4125
12:00	3:30	3217	20.00	161	4038
12:30	4:00	3286	20.20	163	4110

Table 5.5: Flow Test Data Well-B

Time	Duration (HOURS)	Condensate Rate (BPD)	Gas Rate (MMSCFD)	CGR (BBL/MMSCF)	FWHP (PSIG)
8:00	0:00	-	17.902		2950
8:15	0:15	5148	18.054	285	2950
8:30	0:30	5298	18.107	293	2950
8:45	0:45	5274	18.088	292	2942
9:00	1:00	5212	18.088	288	2942
9:15	1:15	5178	18.07	287	2936
9:30	1:30	5143	18.121	284	2941
9:45	1:45	5164	18.103	285	2942
10:00	2:00	5140	18.085	284	2924
10:15	2:15	5129	18.067	284	2922
10:30	2:30	5145	18.067	285	2918
10:45	2:45	5158	18.049	286	2912
11:00	3:00	5088	18.049	282	2906
11:15	3:15	5099	18.049	283	2904
11:30	3:30	5082	18.049	282	2897
11:45	3:45	5051	18.031	280	2897
12:00	4:00	5042	18.014	280	2897

Table 5.6: Flow Test Data Well-C

Time	Duration (HOURS)	Condensate Rate (BPD)	Gas Rate (MMSCFD)	CGR (BBL/MMSCF)	FWHP (PSIG)
19:30	0:00	666	4.23		4501
20:00	0:30	644	4.2	153	4481
20:30	1:00	670	4.2	160	4473
21:00	1:30	615	4.22	146	4459
21:30	2:00	621	4.23	147	4452
22:00	2:30	635	4.23	150	4441

Table 5.7: Flow Test Data Well-D

Time	Duration (HOURS)	Condensate Rate (BPD)	Gas Rate (MMSCFD)	CGR (BBL/MMSCF)	FWHP (PSIG)
22:00	0:00	-	-	-	5343
22:05	0:05	-	-	-	-
22:30	0:30	1632	9.95	164	4919
23:00	1:00	1580	9.95	159	4934
23:30	1:30	1534	9.86	156	4934
23:45	1:45	1514	9.85	154	4928
23:53	1:53	-	-	-	-
0:00	2:00	-	-	-	-
0:15	2:15	1510	9.78	154	4912
0:30	2:30	1508	9.72	155	4918
1:00	3:00	1491	9.69	154	4905
1:30	3:30	1472	9.68	152	4890
2:00	4:00	1450	9.67	150	4875

Table 5.8: Flow Test Data Well-E

Time	Duration (HOURS)	Condensate Rate (BPD)	Gas Rate (MMSCFD)	CGR (BBL/MMSCF)	FHP (PSIG)
21:00	0:00	707	16.22	44	5959
21:15	0:15	718	16.19	44	5964
21:30	0:30	692	16.19	43	5961
21:45	0:45	714	16.19	44	5965
22:00	1:00	673	16.18	42	5969
22:15	1:15	662	16.16	41	5974
22:30	1:30	688	16.16	43	5978
22:45	1:45	673	16.17	42	5978
23:00	2:00	652	16.16	40	5986
23:30	2:30	648	16.17	40	5985
0:00	3:00	655	16.13	41	5986
0:30	3:30	652	15.95	41	5992
1:30	4:30	656	15.92	41	5998
2:30	5:30	639	15.93	40	6012

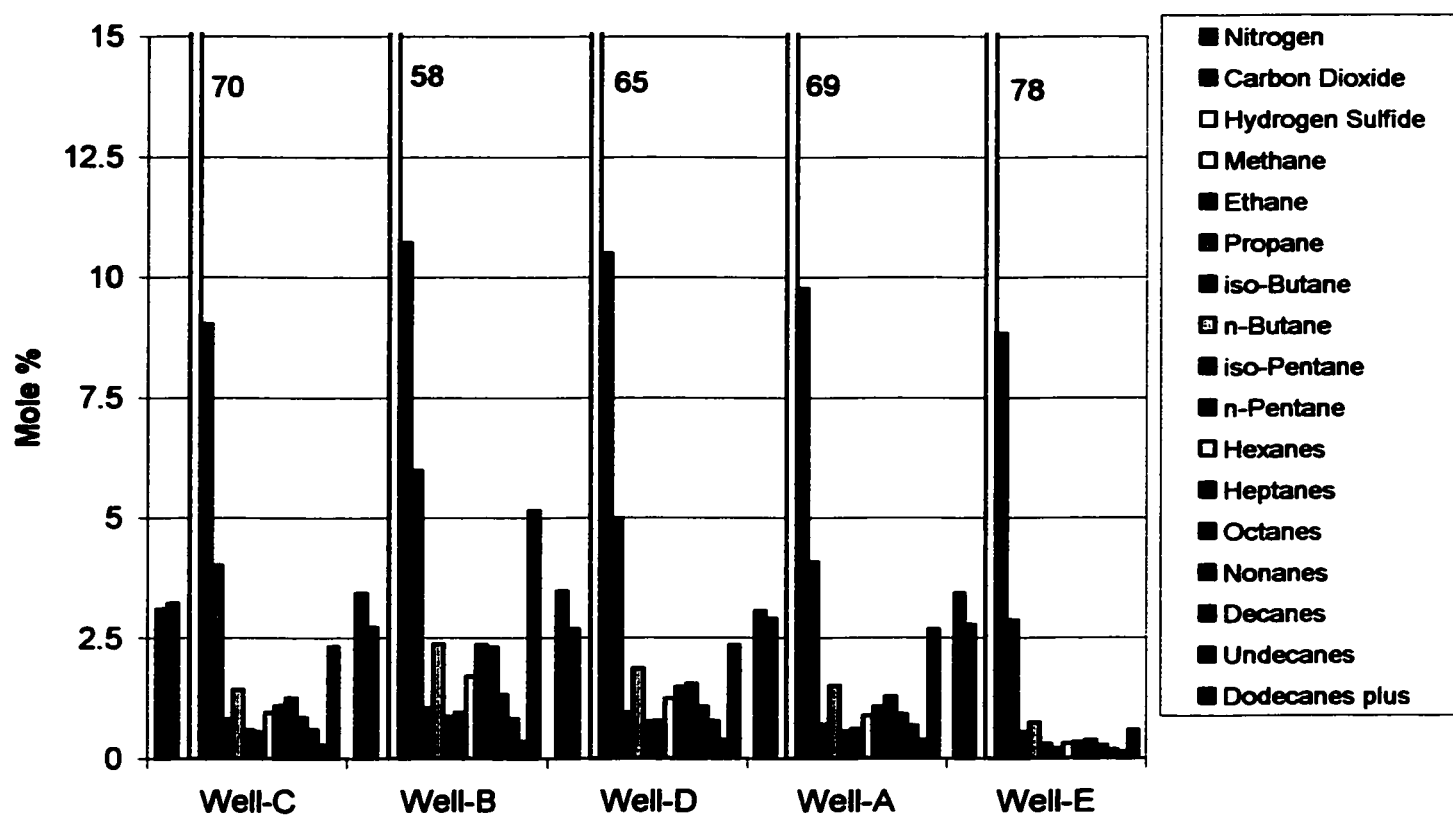


Figure 5.1: Laboratory Measured Gas Composition Distribution

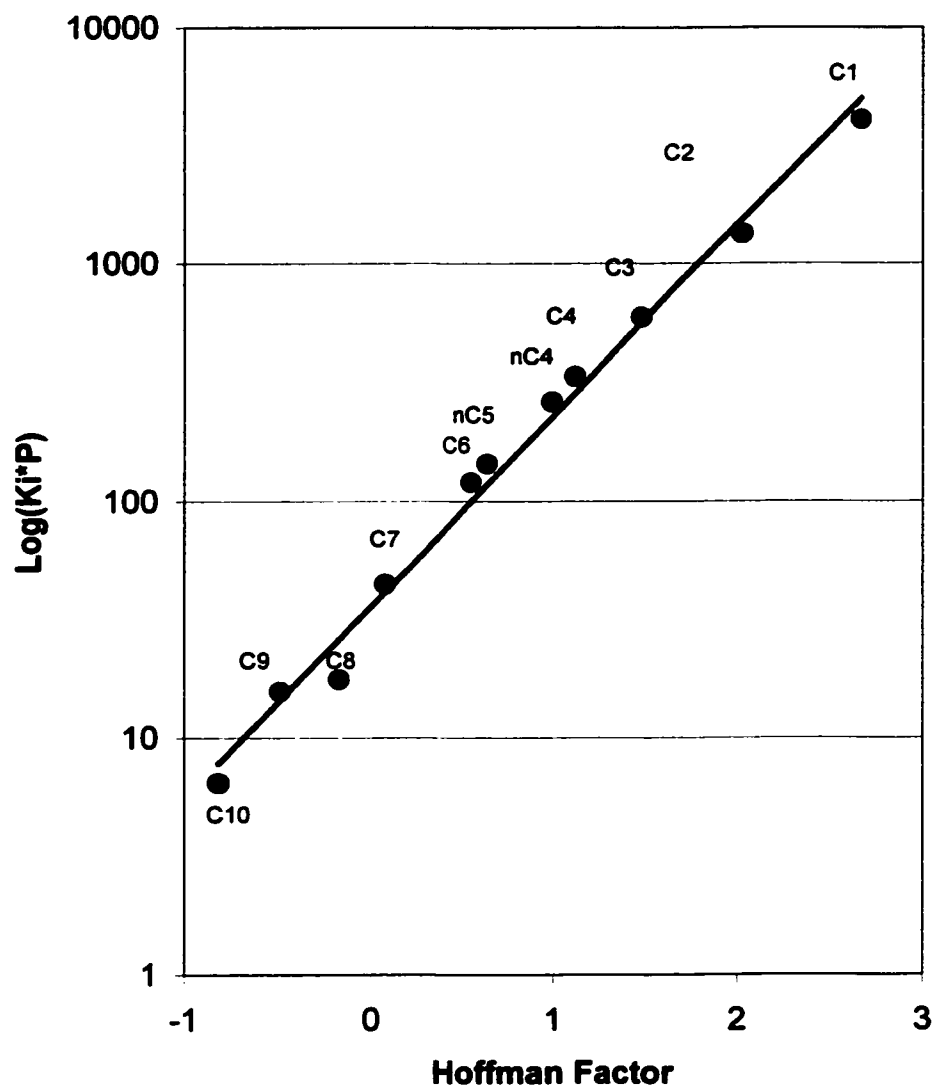


Figure 5.2: Well-A – Hoffman Plot For Data Consistency

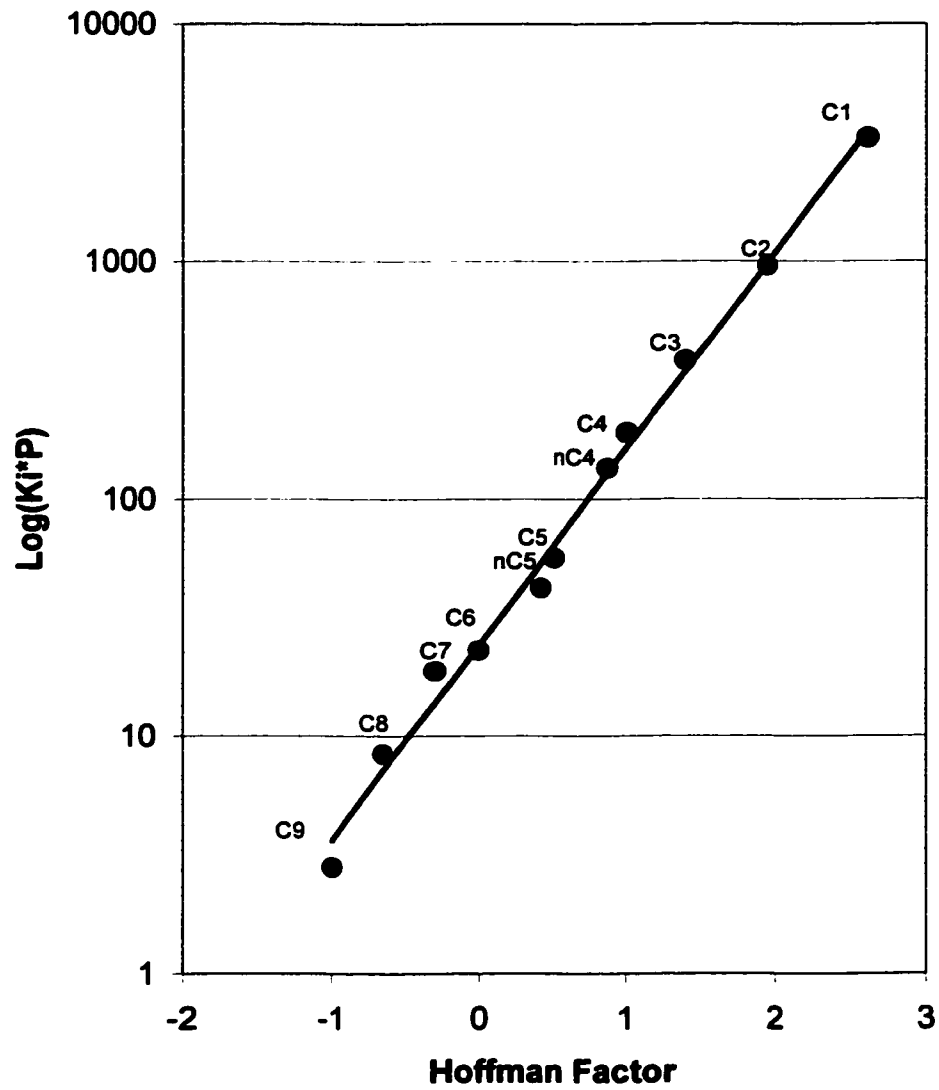


Figure 5.3: Well-B – Hoffman Plot For Data Consistency

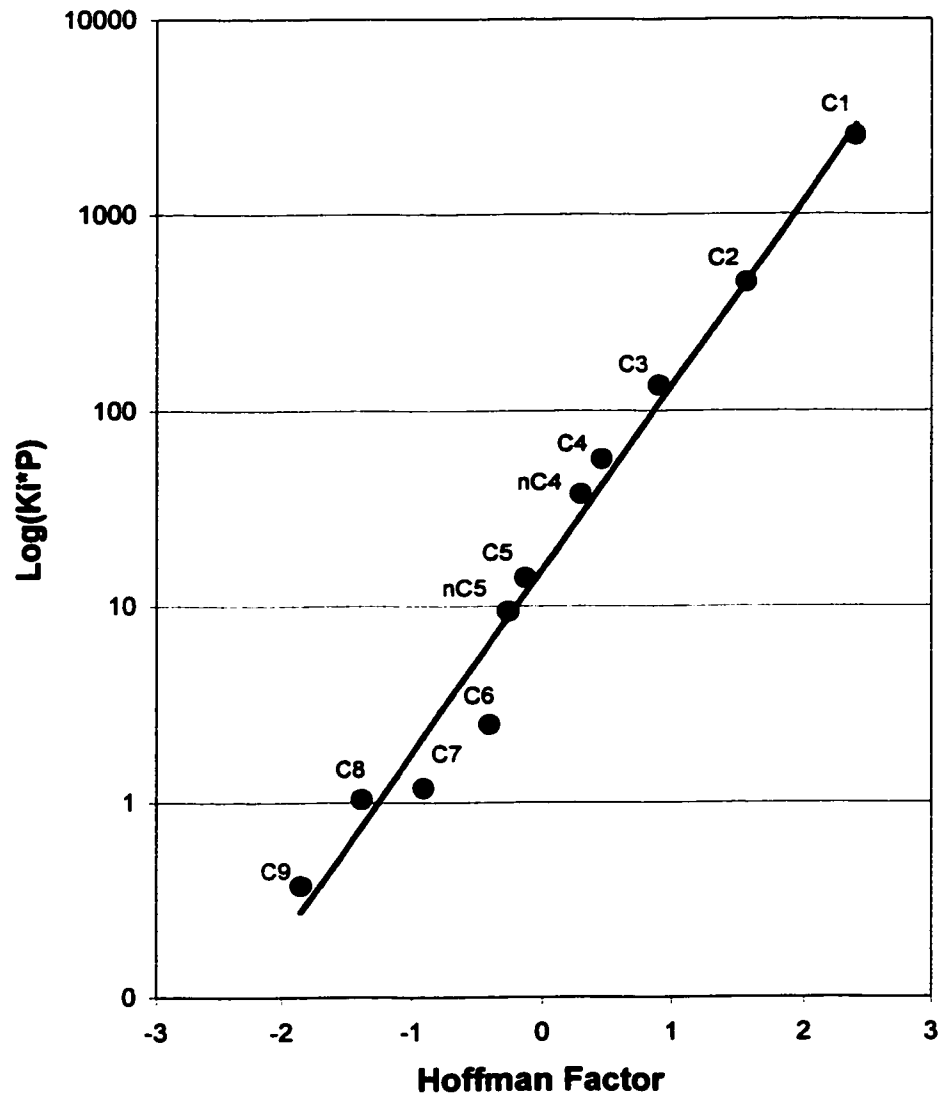


Figure 5.4: Well-C – Hoffman Plot For Data Consistency

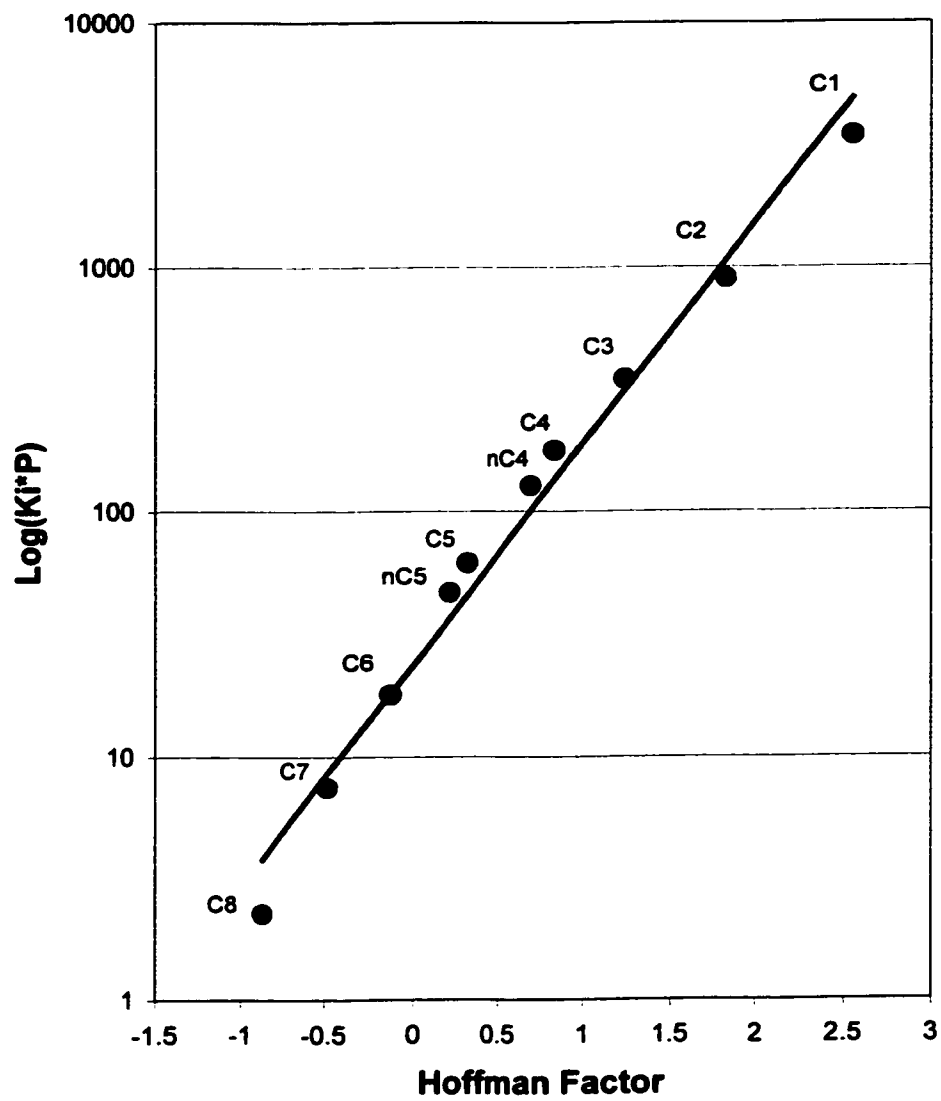


Figure 5.5: Well-D – Hoffman Plot For Data Consistency

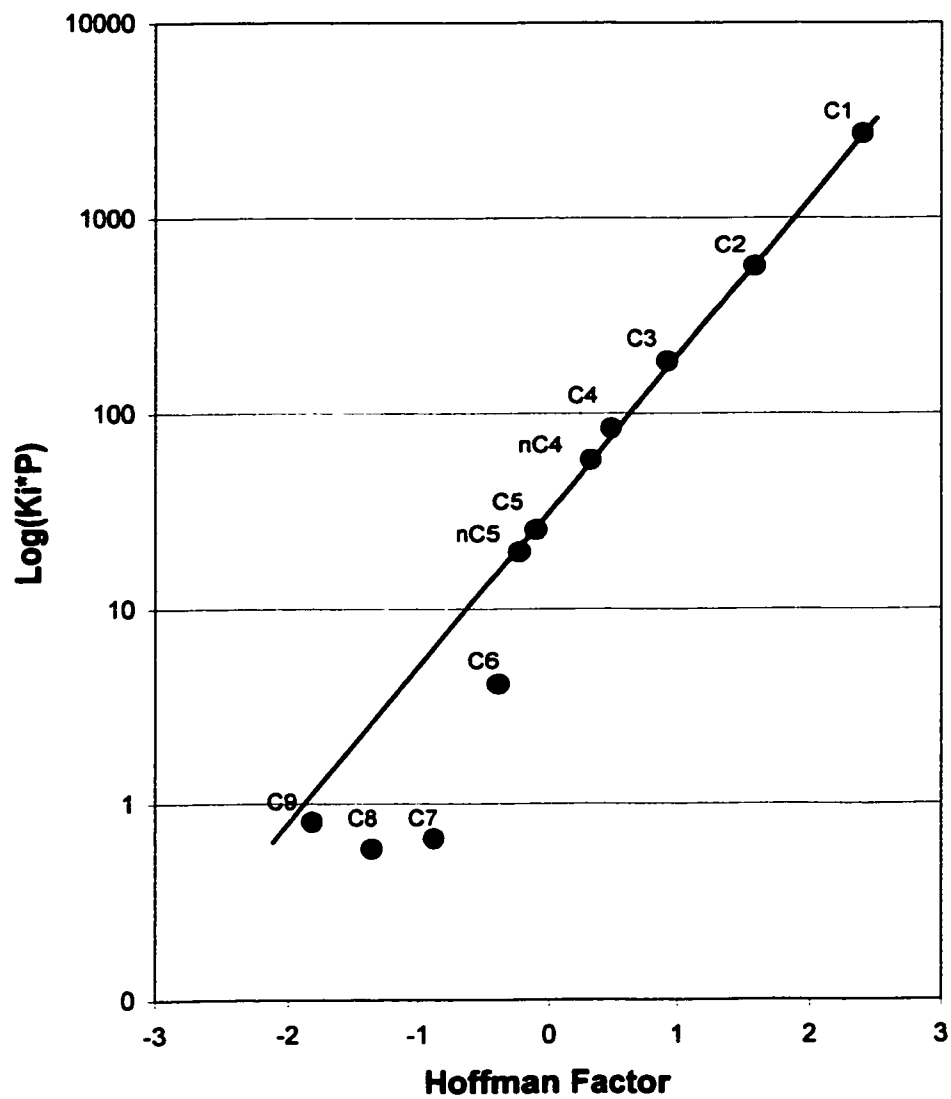


Figure 5.6: Well-E – Hoffman Plot For Data Consistency

5.4 Data Matching

After all PVT laboratory measured data, including the gas composition, were entered in the software, the Critical Pressure (P_c), the Critical Temperature (T_c) and the Acentric Factor (AF) were adjusted to match the laboratory-measured composition using non-linear regression techniques. The C_1 properties (T_c , P_c & AF) were used as regression points along with all components above C_6 . All samples were matched without the need for the binary interaction coefficients between C_1 and the heavier components.

To match laboratory data, the following steps were followed:

- First the saturation pressure was matched
- Second, the Z-factor for the vapour phase was matched
- Finally, the Liquid dropout data during the constant volume depletion (CVD) experiment was matched.

To match the saturation pressure of the samples the splitting of the pseudo components was used. The splitting process involves breaking down the last pseudo into two distributions of 40 components. Once broken down the components are regrouped into two or more pseudo of equal mole percentage. The validity of this operation is based on the fact that any pseudo component is in fact a mixture of many substances with widely different properties. After a

saturation pressure match is obtained, the regression technique is used to adjust the T_c , P_c and AF for the components as mentioned above. The regression process will stop when a maximum number of steps has been reached (20 steps were used) or the error term falls below $1e^{-9}$.

Table 5.9 compares the laboratory measured saturation pressures with the matched pressures. As can be seen from the table, a very good match was obtained for all saturation pressures. Figures 5.7 to 5.14 show the quality of data matching for liquid dropout and Z-factor for the vapour phase. As can be seen from these figures, a good match of laboratory-measured Z-factor and liquid dropout was achieved. All samples were matched very smoothly with the exception of sample Well-E. The sample could not be matched, which also suggests that Well-E sample is not a representative sample.

Table 5.9: Dew Point Pressure Summary

<i>Well</i>	<i>Measured</i>	<i>Calculated</i>	<i>Delta (Measured - Calculated)</i>
<i>Well-A</i>	5530	5531.7	-1.7
<i>Well-B</i>	4521	4521.0	0
<i>Well-C</i>	5973	5973.0	0
<i>Well-D</i>	5138	5138.0	0
<i>Well-E</i>	5522	5520.7	1.3

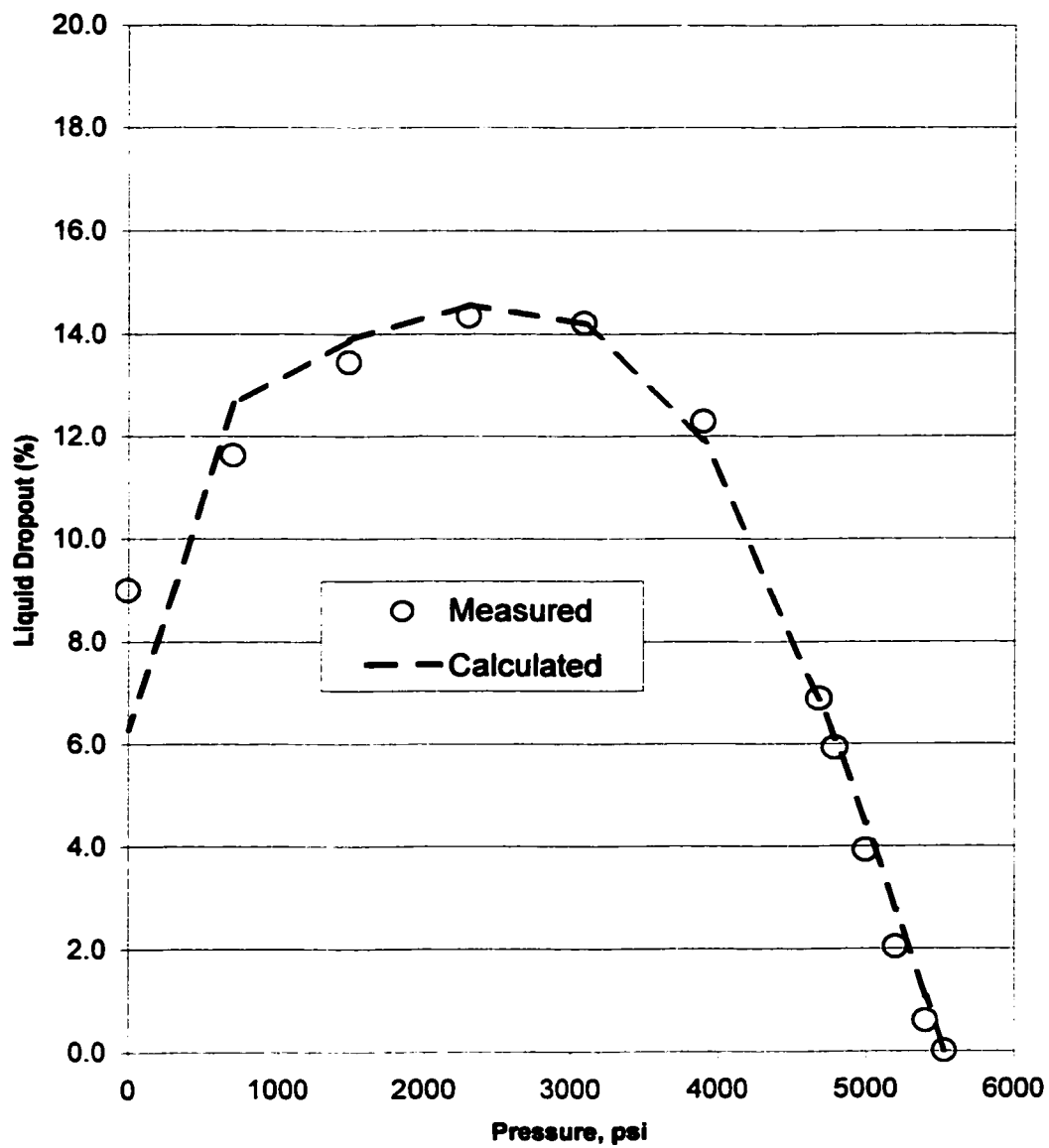


Figure 5.7: Well-A – Percent Retrograde Liquid Curve During CVD Experiment

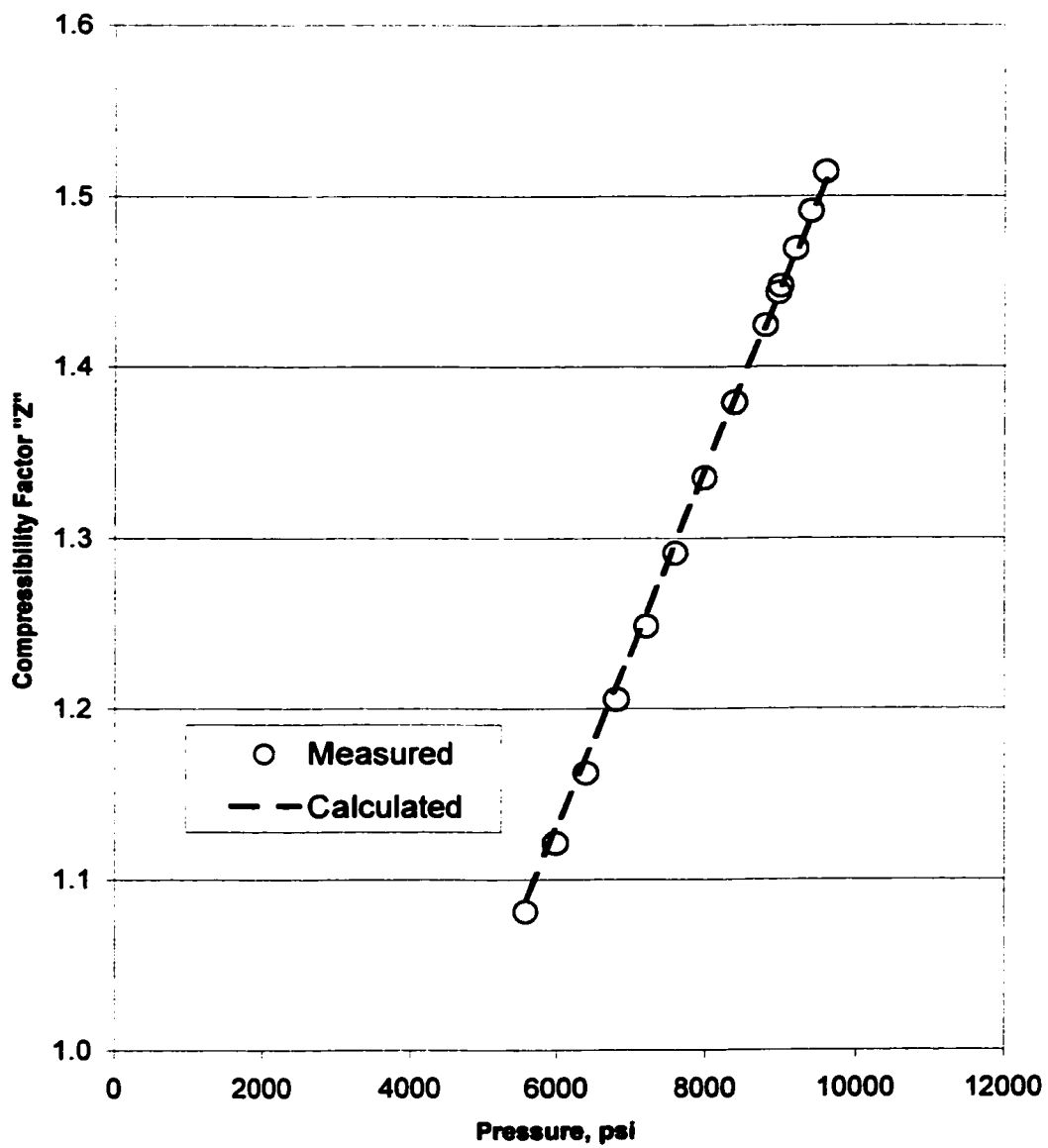


Figure 5.8: Well-A – “Z” Factor During CCE Experiment

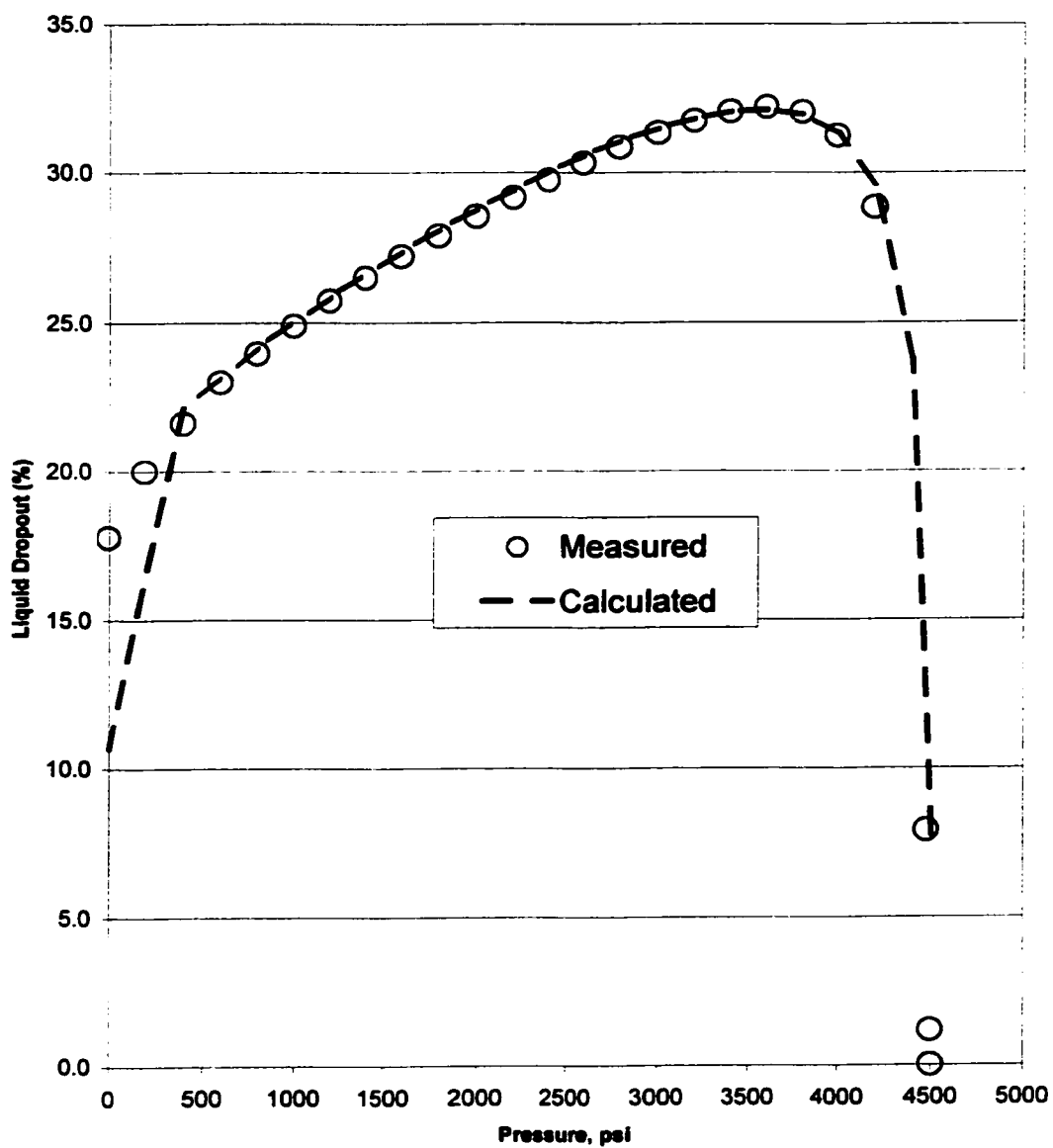


Figure 5.9: Well-B – Percent Retrograde Liquid Curve During CVD Experiment

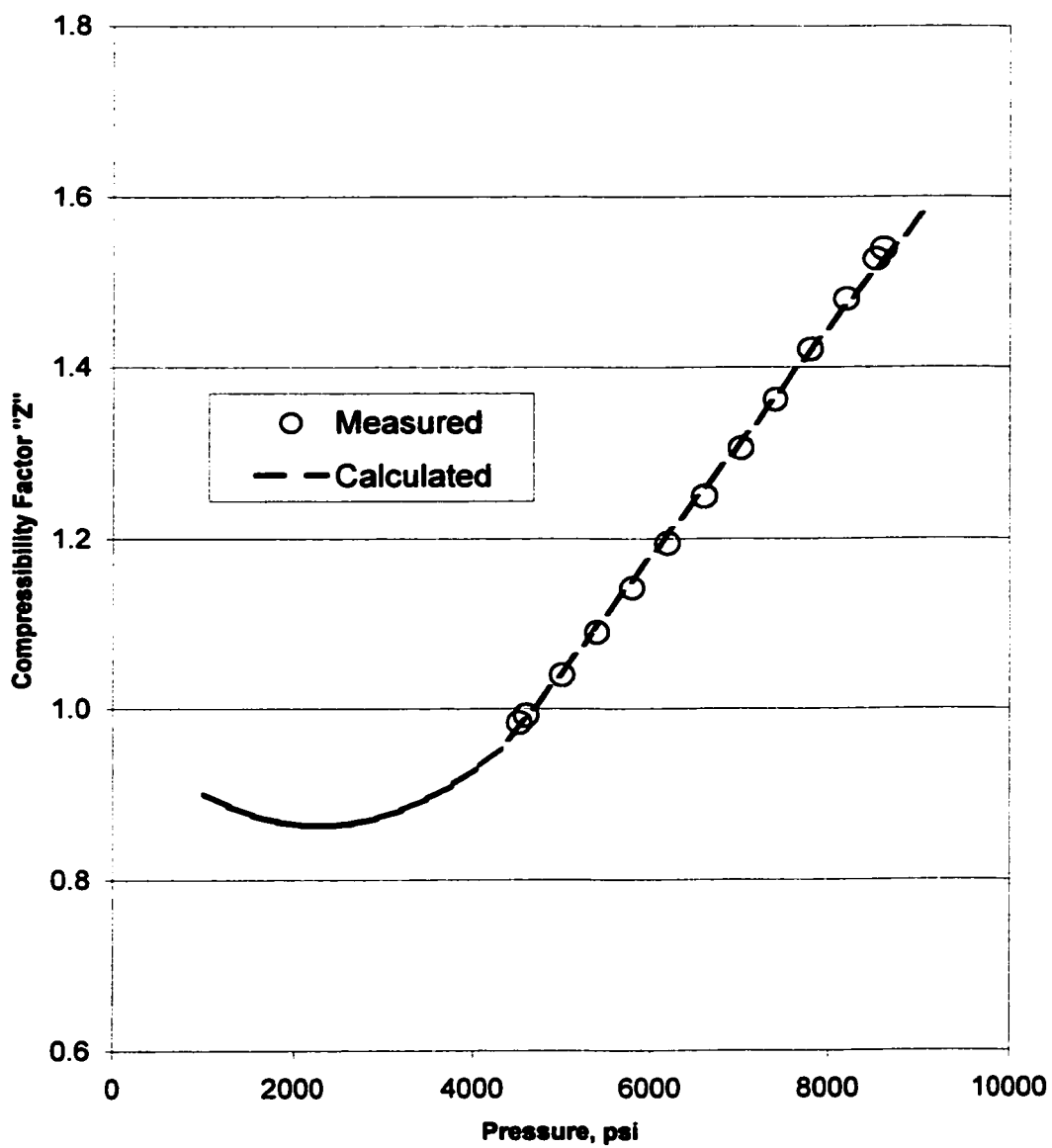


Figure 5.10: Well-B – "Z" Factor During CCE Experiment

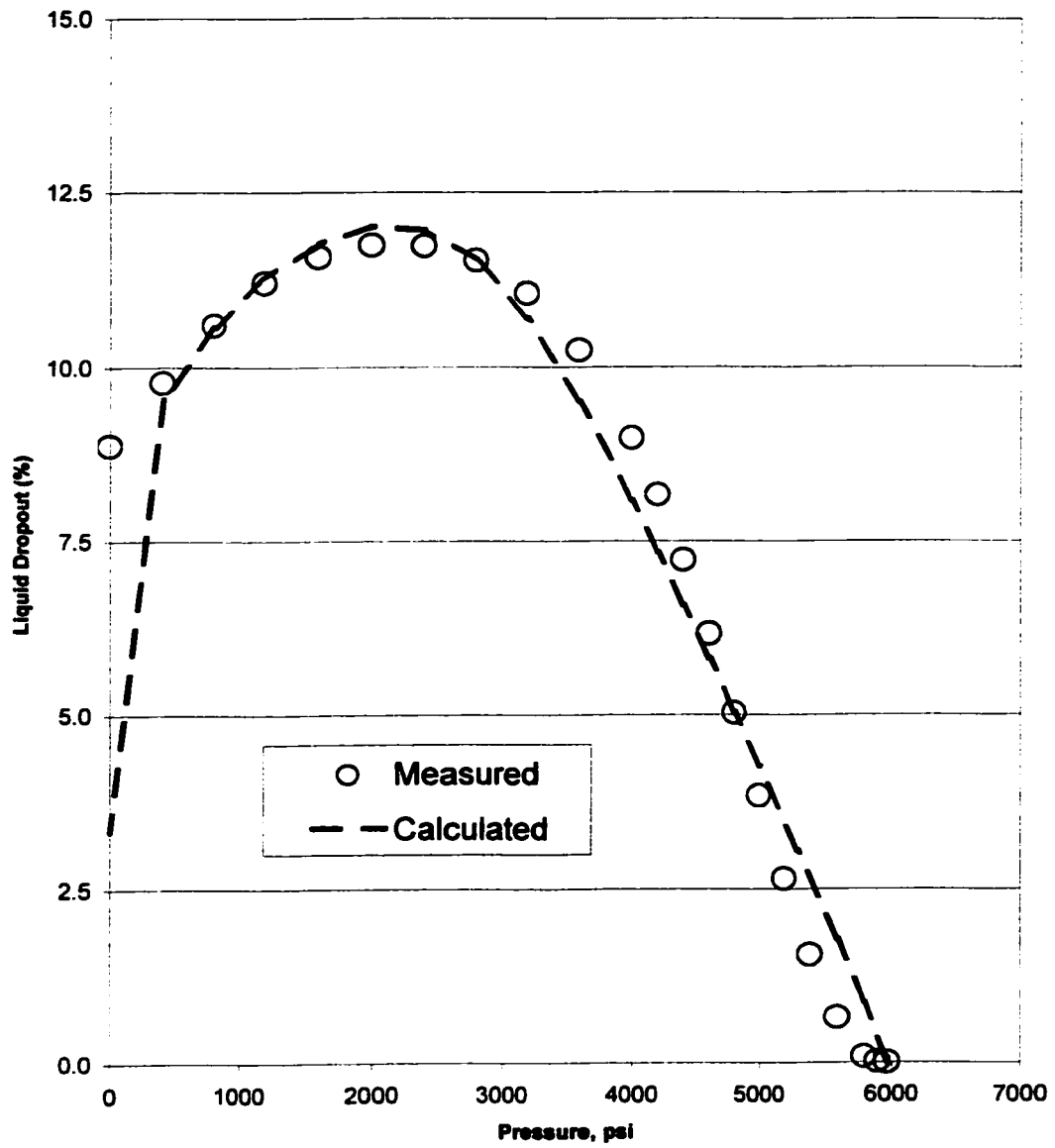


Figure 5.11: Well-C – Percent Retrograde Liquid Curve During CVD Experiment

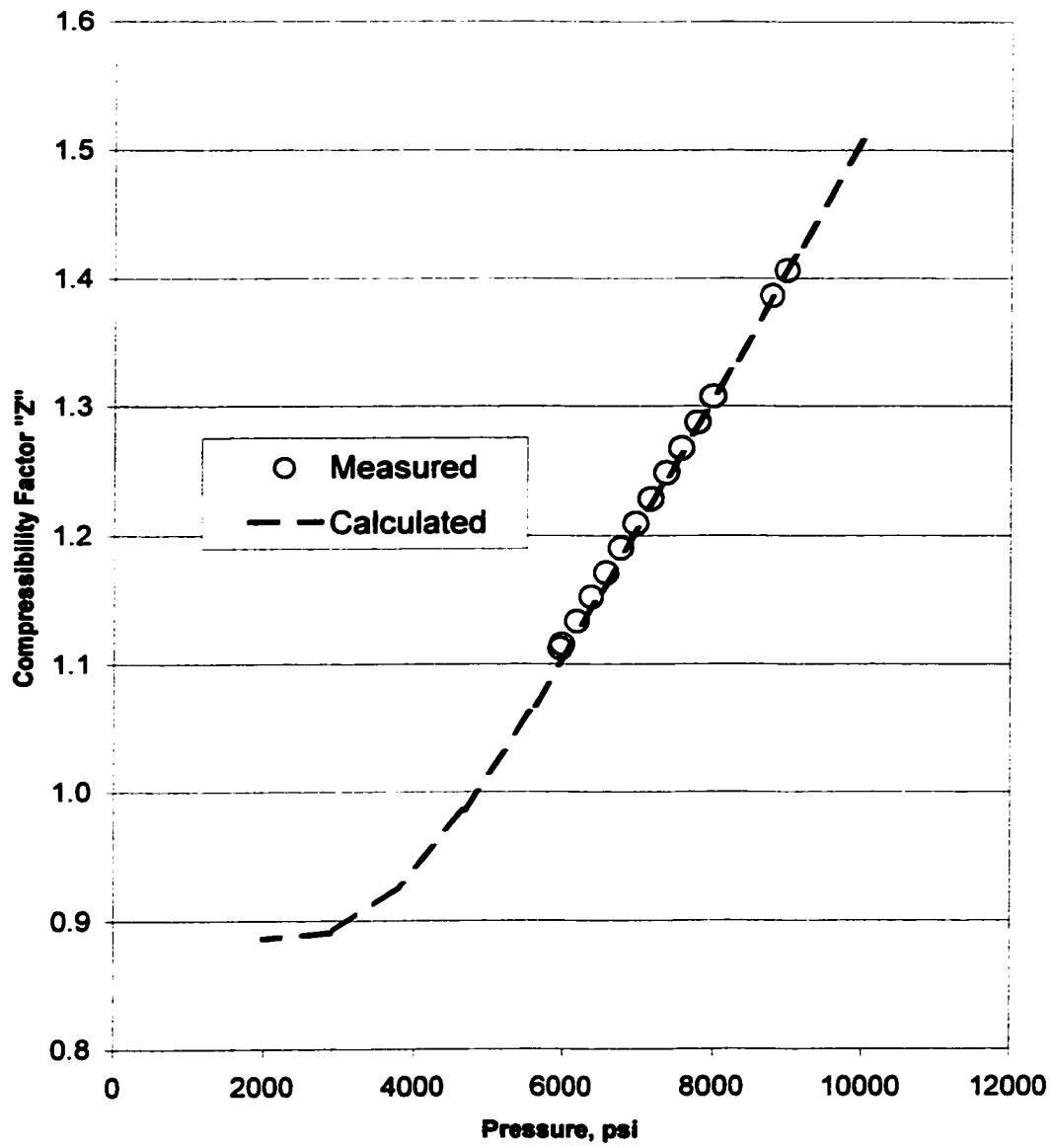


Figure 5.12: Well-C – “Z” Factor During CCE Experiment

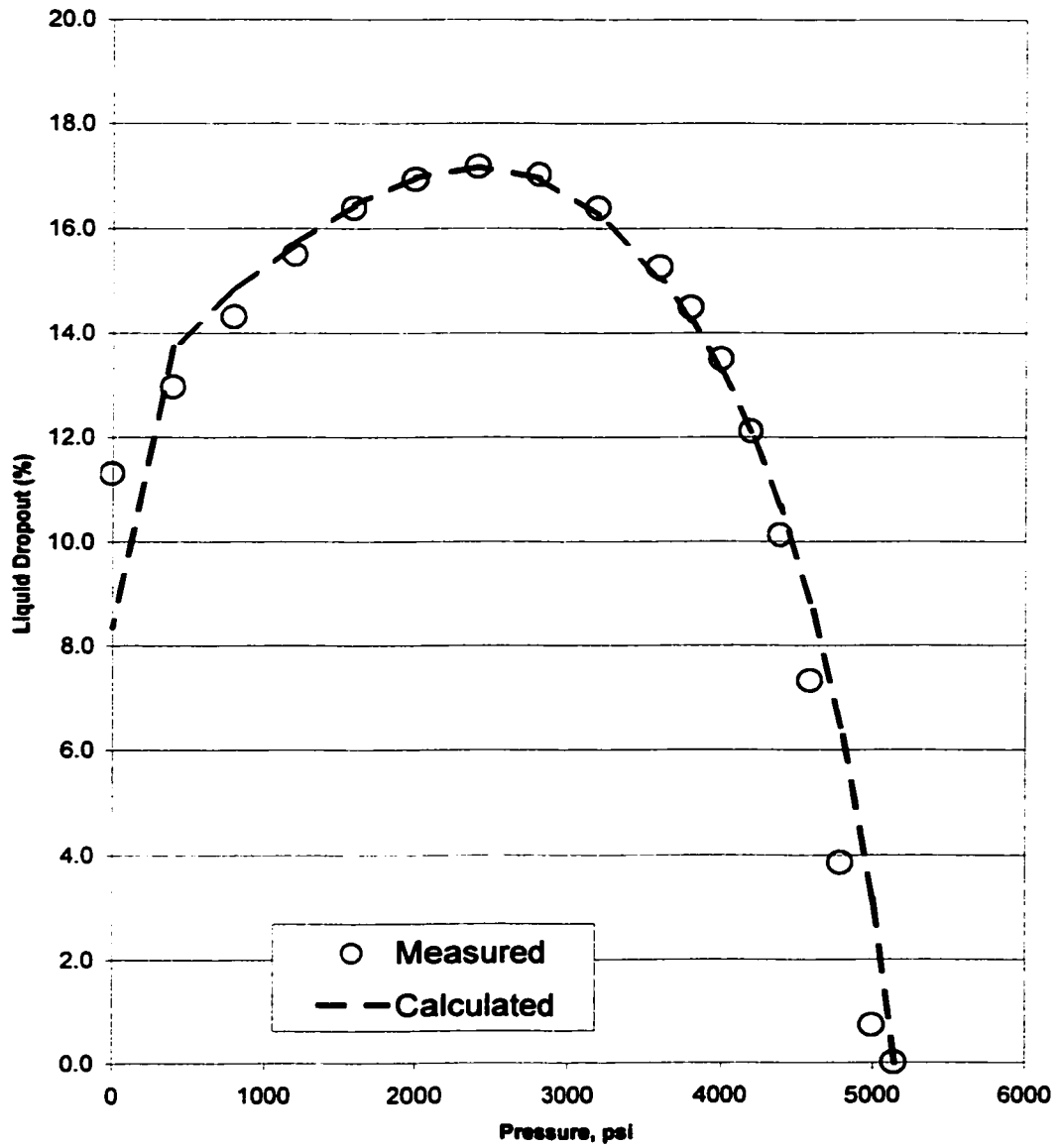


Figure 5.13: Well-D – Percent Retrograde Liquid Curve During CVD Experiment

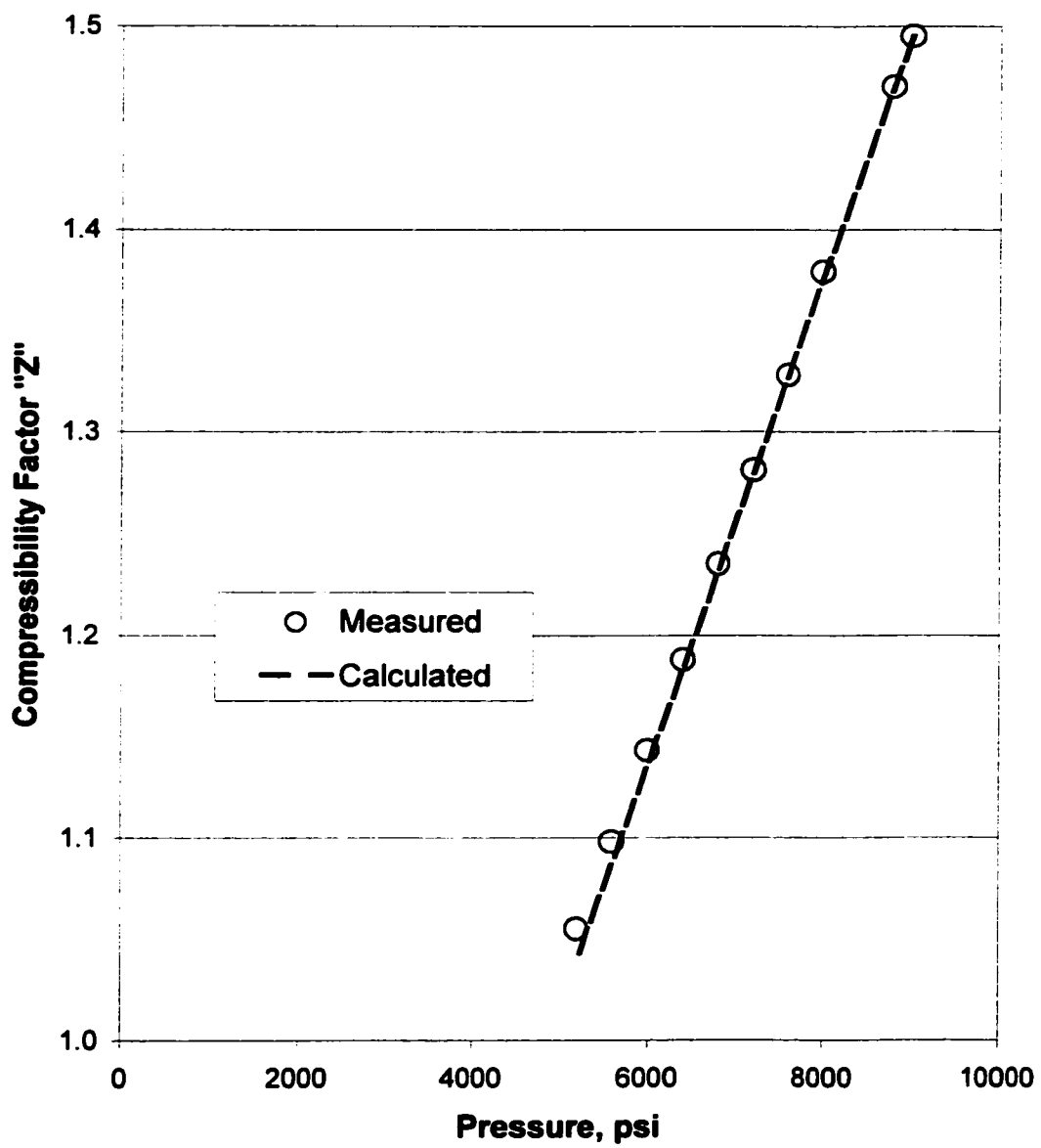


Figure 5.14: Well-D – "Z" Factor During CCE Experiment

5.5 Gradient Calculations

After tuning the EOS for all samples, the compositional gradient option was used to calculate the expected change in composition with depth across the sampled interval. The temperature gradient in the reservoir, as calculated from bottom-hole temperature measurements was approximately 1° F/100 ft. This temperature gradient of 1° F/100 ft. was used in the calculations. The results of the calculations, for C₁ and C₇₊ components for all samples, are shown in Figure 5.15. All samples showed a smooth and gradual compositional gradient trend with depth.

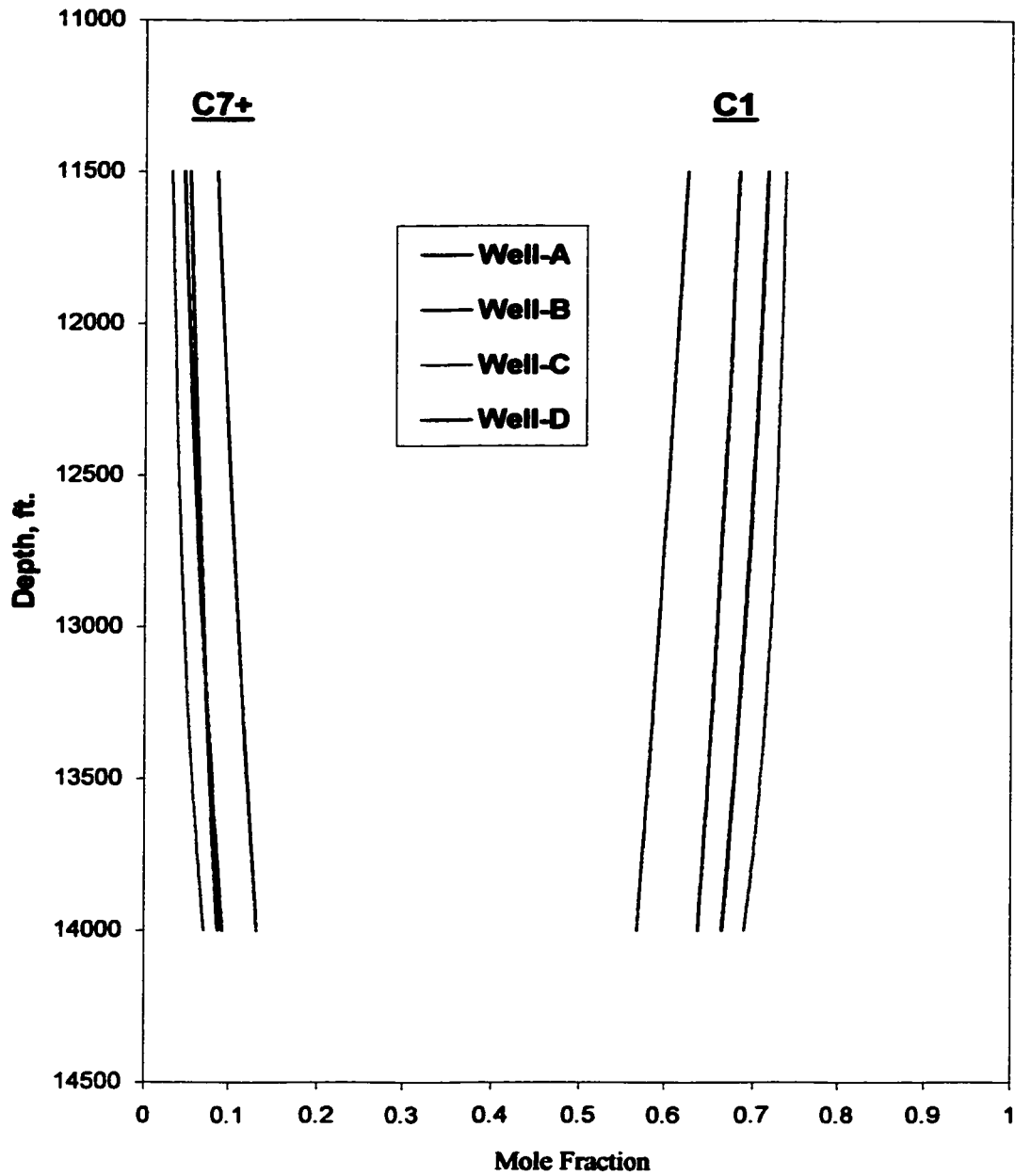


Figure 5.15: Calculated Compositions for All Wells

5.6 Discussion

In the pervious sections the five available PVT samples were checked for validity and found that four of them are good samples (Well-A, B, C & D). When the composition change with depth was calculated using the tuned EOS equations (see Figure 5.15), it showed that the expected change in composition is gradually decreasing with depth for C_1 and gradually increasing with depth for C_{7+} components. This trend is also seen from the laboratory compositional analysis of the collected samples as shown in Figure 5.16 with the solid circles. Such a trend, where the concentration of the heavier components increases and the concentration of the lighter components decreases with depth, is the normal trend in a hydrocarbon column under no thermal diffusion (or thermal equilibrium).

The calculated gradient of the composition change was very consistent from all samples and was very gentle. This suggests that the expected change of composition as a result of gravity forces should follow this trend and any significant deviation from this trend indicates a lack of communication between the fluids.

When we look into the laboratory data trend, we see that it shows an increasing trend for the C_1 component with decreasing depth with the exception of Well-C.

The same trend is also true for the C7+ component. One might conclude that Well-C is not in communication with the other wells because its composition does not follow the general trend indicated by the composition from the other wells.

But when the slope of the change in the composition, from the laboratory analysis is compared to the calculated slope, we see that it is very sharp as can be seen from Figure 5.16. This amount of compositional change with depth can not happen as a result of gravity forces alone, as suggested by the calculated curves from all samples. When the calculated composition of Well-A (the middle well in terms of depth) is plotted with the laboratory measured composition for all wells, it was found that Well-C & D samples fall within the expected range (less than +/- 5%). This suggests that the change in composition observed between these wells (Well-A, C & D) can be explained by the gravity effect and the wells are probably in communication. In addition, the data suggests that the reservoir is at thermal equilibrium.

Even though Well-B is only 6.25 Km from Well-A (see Figure 5.17), the observed deviation was more than 15% less than the calculated composition for C₇. The other two wells, Well-C and Well-D, are 9.0 Km and 3.5 Km from Well-A respectively. This difference in composition seen in Well-B can not be justified

by the effect of gravity forces alone, which suggests a possible barrier may exist (sealing fault) between this well and the other wells.

The reservoir geological data in the area supports this conclusion. Figure 5.17 shows the results of a recent 3-D seismic data. The data shows that many faults exist in the reservoir, and these faults are running in all directions in the area of interest. Pressure build-up data did also indicate the presence of faults around some of the wells.

Furthermore, Figure 5.17 shows that Well-B is setting in a separate fault-block from the other wells. In addition, the analysis suggests that the faults separating Well-C from the other wells are not sealing faults.

As can also be seen from Figure 5.17, the top section of the reservoir is missing around the area of Well-E. This makes the possibility of having communication between the reservoir and the one above very high. This could have been the reason of not obtaining a good representative sample from this well.

The compositional gravity calculation analysis findings are consistent with other studies made in this area. Carrigan et al. (Carrigan 1998, [3]) conducted a thermal maturity modeling study for the source rock in the area and identified two kitchen areas that were feeding the Ghawar structure. The geochemistry of the oils and condensates indicates two groups, each generated from a different

hydrocarbon kitchen, suggesting that the two kitchens differ slightly in organic facies. Within each group, variations among hydrocarbons are related to the thermal maturity of the source rock during the generation process. He also stated that the juxtaposition of reservoir and sealing units, caused by both faulting and erosion, led to the development of complex combination of structural-stratigraphic traps in the Jauf formation.

The preservation of such differences in composition that resulted from the thermal maturity of the source rock during the generation and expulsion process indicates that the Jauf reservoir is incompletely mixed and is composed of several compartments. These compartments were existing before or during the generation and expulsion process.

Carrigan et al., in another study (*Carrigan 1997, [2]*), used the geochemical fingerprinting technique to assess the extent of fluid continuity in the Jauf reservoir and to identify the individual reservoir compartments. He came to the conclusion that Well-D and Well-C are in fluid communication as indicated by the fingerprinting analysis because their condensates are very similar. He also made a similar conclusion for Well-A and Well-B and made the statement that a lack of fluid communication between them exists. But he could not explain why Well-D, which is located between Well-A and Well-B, is different in composition without a geological evidence for the presence of a fault between them.

The gravity gradient calculation analysis agrees with the first conclusion made by Carrigan in that Well-D and Well-C are in fluid communication, but does not agree with the second conclusion. It in fact suggests that Well-A, C & D are in fluid communication and Well-B is not as can be seen from the large deviation of its composition from the calculated trend. This conclusion is supported by the 3-D seismic data that is showing Well-B in a separate fault block from the other wells.

The small deviation from the calculated composition observed in Well-C and Well-D data, could be the effect of the porous media. In hydrocarbon reservoirs the capillary network is very complex. The process of transporting the molecules in the reservoir is a function of the capillary dimensions and the mean free path for the molecules. These two factors are directly related to the porous medium characteristics such as the porosity and permeability, which are not considered in the calculations.

To investigate the presence of a **gas-oil contact**, saturation pressure with depth needs to be calculated. When the GOC is reached, a sharp decrease in the saturation pressure will be seen as a result of phase change from gas to liquid (from dew point to a bubble point).

In Figure 5.18 there is no indication for the existence of a GOC or an oil rim within the reservoir limits. If the reservoir was thick enough, an interesting situation will be seen. The calculated saturation pressures suggest that the fluids in the reservoir will change from gas to liquid without passing through a GOC. This will happen because the reservoir pressure is much higher than the critical pressure of the fluids.

The existence of such contact would significantly reduce the gas reserves in the reservoir, as some of its volume is occupied by liquids. These types of liquids are usually very difficult to recover due to early gas breakthrough.

The information about the reservoir continuity is very important for the reservoir development and has to be considered very early in the planning stages. Usually the development of this type of reservoirs, where the gas is very rich, considers a gas cycling project to maximize the condensate recovery over the reservoir production life. If such barriers are not considered in the initial planning of the reservoir development, the success of the cycling project will be in risk.

Furthermore, it will lead to spending unnecessary capital as a result of improperly placing gas injectors and producers in the field. This additional capital can significantly reduce the profitability of the project or in some cases will lead to turning the project to uneconomical project

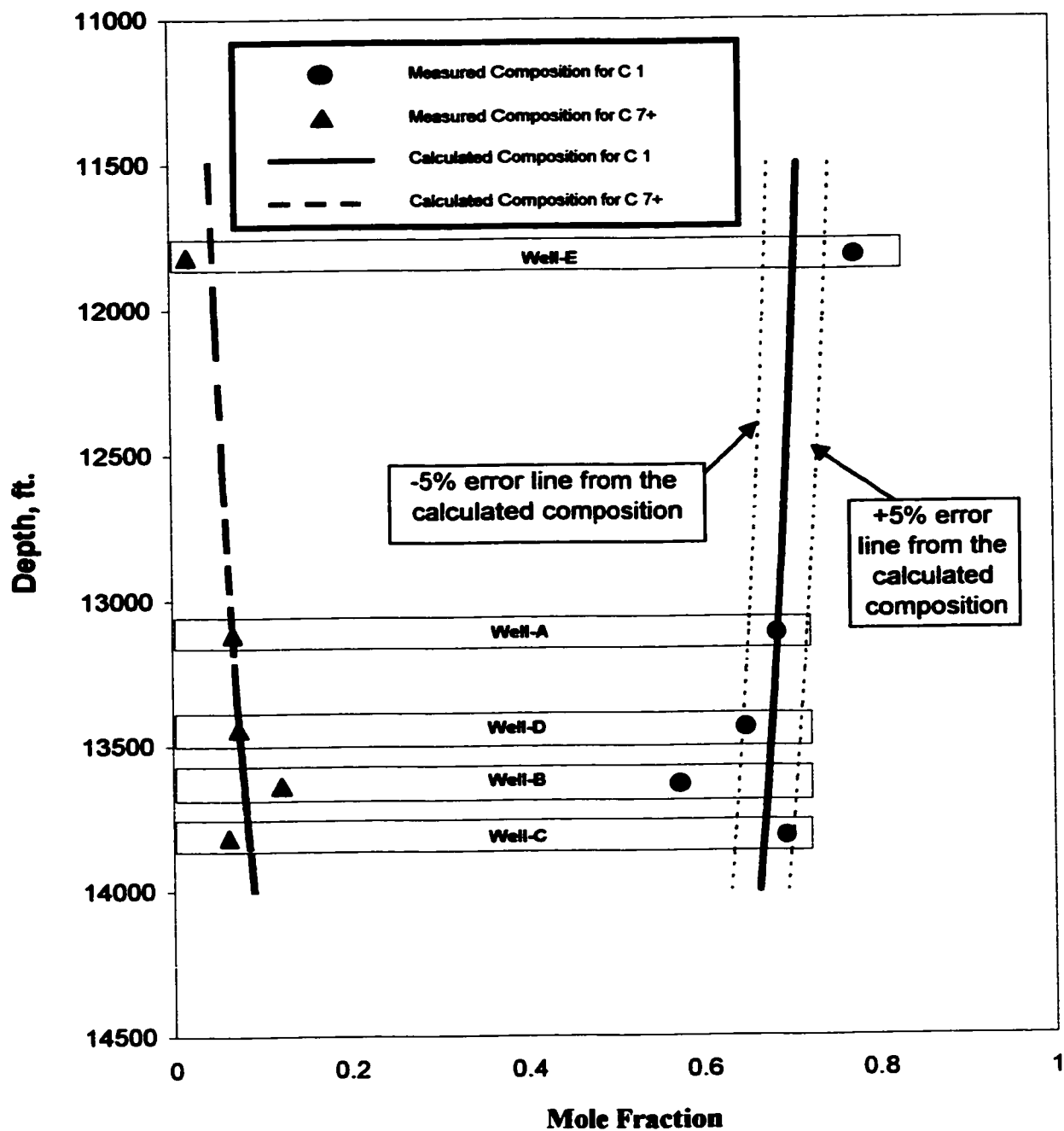


Figure 5.16: Calculated vs. Measured Composition of C₁ & C₇₊

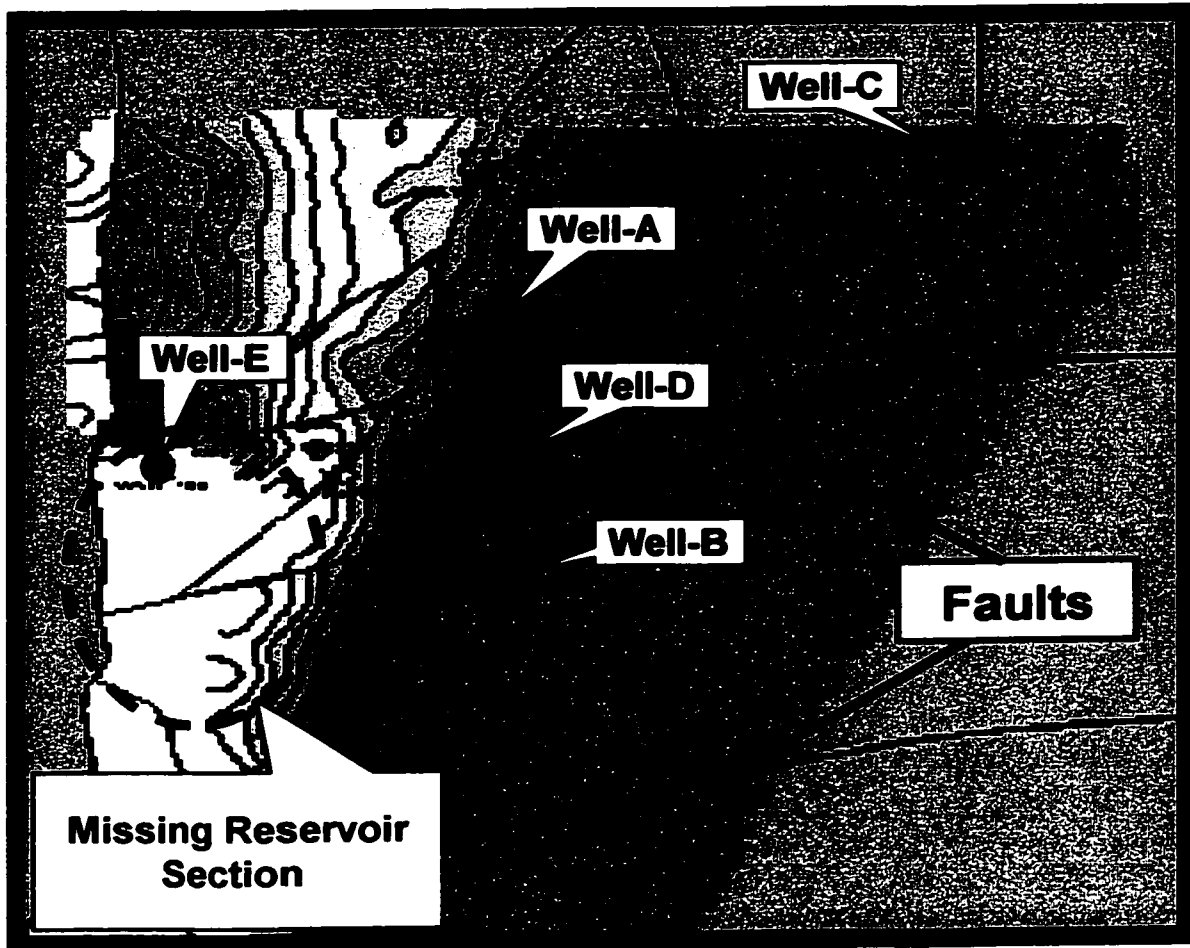


Figure 5.17: Top of the Reservoir 3-D Seismic Map

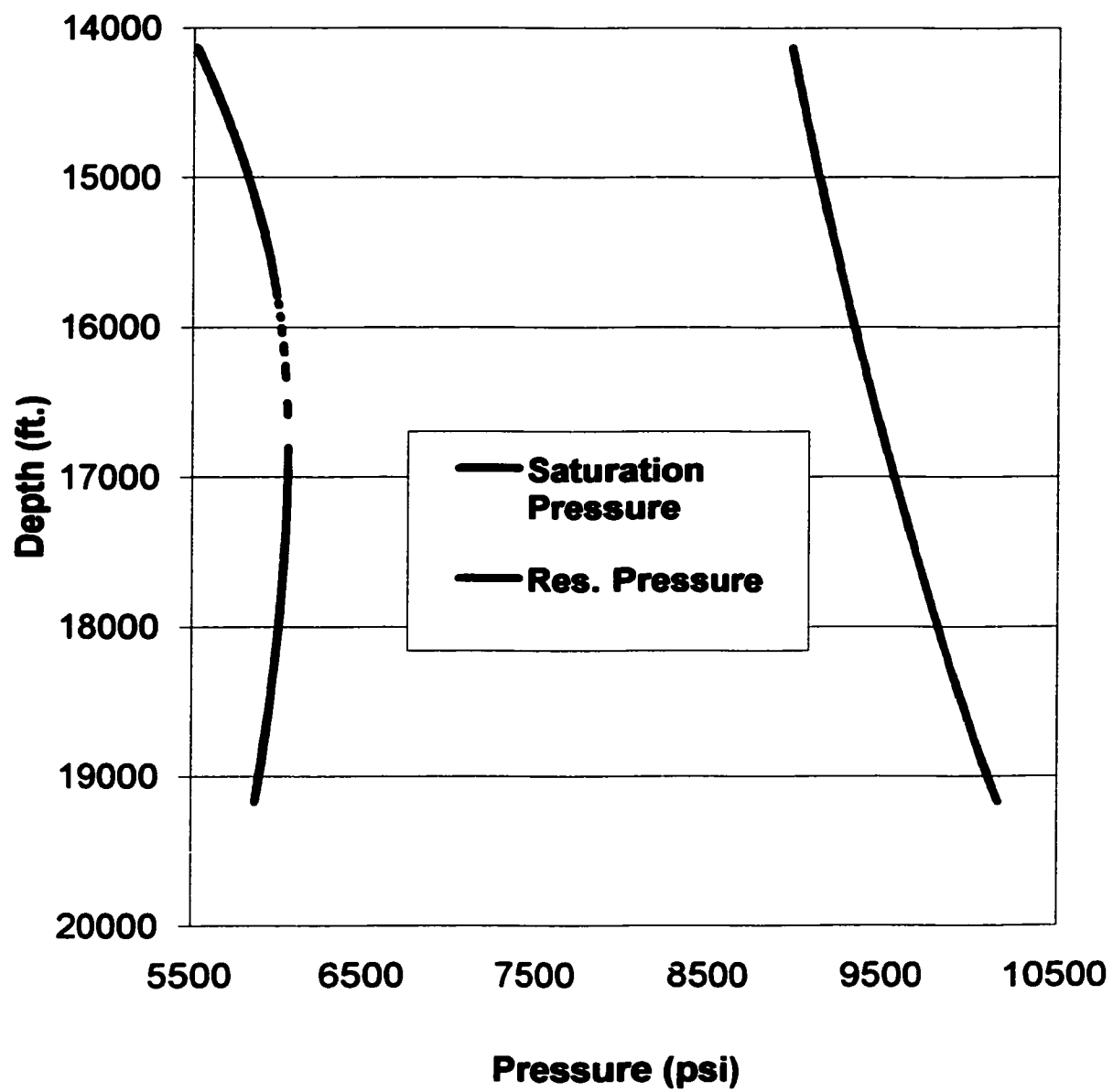


Figure 5.18: GOC Prediction Plot, Well-A Data

CHAPTER 6

CONCLUSIONS

The method of compositional gradient variation calculations technique suggests the existence of reservoir barriers in the reservoir and the observed variation in the composition can not be explained by the effect of gravity forces alone. This was supported by a recent 3-D seismic data that showed several faults in this reservoir. The technique of compositional gradient calculations is very helpful to understand the reservoir continuity. The study suggests that not all of the wells are in communication and not all of the faults are sealing faults. No GOC is expected to be seen in this reservoir.

CHAPTER 7

RECOMMENDATIONS

It is highly recommended to consider the reservoir discontinuity during the reservoir development planning process. It is also recommended to update this study with new samples in the future and apply the same method to help understand the reservoir connectivity. It is also recommended to use a compositional numerical simulation to evaluate the impact of the variation in gas composition on the estimation of the hydrocarbon volumes in place.

APPENDICES

Appendix A: Software Used for Analysis

The software used in this study is one of the commercial Pressure Volume and Temperature (PVT) analysis software packages. The PVT package from Petroleum Experts Limited. Version 4.01 was used.

The company's address is:

Petroleum Experts Limited
21 Lansdowne Crescent
Edinburgh, Scotland
EH12 5EH
Tel: (44 131) 313 5728
Fax: (44 131) 346 8956

Appendix B: Hoffman Method

The technique, suggested by Hoffman et al. is a graphical method for examining compositional data from two equilibrium phases, in order to verify the compositional measurements against correlation using the reported equilibrium conditions. The authors suggested that a plot of the functions listed below should produce something close to a straight line and any major deviations from the trend indicate non-equilibrium streams.

First function:

$$\log(k_i * P_i) \quad \text{Where} \quad k_i = \frac{y_i}{x_i}$$

Second function:

$$HoffmanFactor = \frac{(\log_{10}(P_{c,i}) - \log_{10}(P_{ref})) \left(\frac{1}{T_{b,i}} - \frac{1}{T_{sep}} \right)}{\left(\frac{1}{T_{b,i}} - \frac{1}{T_{c,i}} \right)}$$

Appendix C: Field and Laboratory Data

- **Well-A PVT Tables**
- **Well-B PVT Tables**
- **Well-C PVT Tables**
- **Well-D PVT Tables and Build-up Data**
- **Well-E PVT Tables**

Well-A PVT Table 1

SAMPLING INFORMATION - Well-A**WELL DATA**

Reservoir	Pre-Khuff (DST-3)
Elevation, ft. DF	937
Perforated Interval (OH), ft DF	18650-14353
Completion Depth, ft. OF	Open Hole
Static Bottom-hole Pressure, psig	8973 @ 14172 ft. DF
Reservoir Datum Temperature, °F	298@ 14172ft. DF
Static Bottom-hole Temperature, °F	298 @ 14172 ft. DF
Flowing Bottom-hole Pressure, psig	8263 @ 14172 ft. DF
Flowing Bottom-hole Temperature, °F	298@ 14172 ft. DF
Shut-in Pressure (Wellhead), psig	6300 (Tubing)
Source of Data	Reservoir Engineering

SAMPLING DATA

Sampling Date	May 28, 1994
Type of Sample	Recombination(Gas & Condensate)
Sampling Depth, ft. DF	Surface
Flowing Pressure (Wellhead), psig (Tubing)	4038 @ 19.98 MMSCFD gas 3553 BPD Condensate
Flowing Temperature (wellhead), °F	212
Status of Well	Exploratory
Separator Pressure, psig	1030
Separator Temperature, CF	177
Separator GOR, SCF/Sep. bbl	5623

Well-A PVT Table 2

**HYDROCARBON ANALYSES OF SEPARATOR PRODUCTS AND CALCULATED
WELL STREAM - WELL-A**

<u>Component</u>	<u>Separator Liquid</u>		<u>Separator Gas</u>		<u>Well Stream</u>	
	<u>Mol%</u>		<u>Mol%</u>	<u>GPM</u>	<u>Mol%</u>	<u>GPM</u>
Nitrogen	0		0		0	
Carbon Dioxide	1.27		3.19		2.92	
hydrogen Sulfide	0.35		3.51		3.07	
Methane	19.4		76.75		68.77	
Ethane	7.77		10.09	2.698	9.77	2.612
Propane	6.4		3.71	1.021	4.09	1.124
Iso-Butane	1.68		0.55	0.18	0.71	0.231
n-Butane	4.22		1.08	0.34	1.52	0.478
iso-Pentane	2.21		0.31	0.113	0.57	0.21
n-Pentane	2.56		0.3	0.109	0.62	0.223
Hexanes	5.09		0.22	0.09	0.9	0.366
Heptanes	7.03		0.12	0.055	1.08	4.658
Octanes	8.55		0.13	0.067	1.3	
Nonanes	6.38		0.04	0.023	0.92	
Decanes	4.92		0	0	0.68	
Undecanes	2.76		0	0	0.38	
Dodecanes plus	<u>19.41</u>		<u>0</u>	<u>0</u>	<u>2.7</u>	
	100.00		100.00	4.696	100.00	9.902

Properties of Heptanes Plus

API Gravity @ 60°F	44.4	62.1
Density, gm/cc @ 60 °F	0.8034	0.7303
Molecular Weight	167	127

Properties of Dodecanes plus

API Gravity @ 60°F	37.2
Density, gm/cc @ 60 °F	0.8378
Molecular Weight	237

Calculated separator gas gravity (air = 1.000) = 0.734

Calculated gross heating value for separator gas
per cubic foot of dry gas @ 14.73 psia and 60 °F = 1152 BTU

Primary separator gas collected @ 1030 psig and 177 °F
Primary separator liquid collected @ 1030 psig and 177 °F

Primary separator gas / separator liquid ratio = 5623 SCF/BBL @ 1030 PSIG & 177°
Primary separator gas / well stream ratio = 860.88 MSCF/MMSCF

* GPM value is for C7 plus fraction

Well-A PVT Table 3

PRESSURE-VOLUME RELATIONS OF RESERVOIR FLUID AT 298^o F
(Constant Composition Expansion) - Well-A

<u>Pressure</u> psia	Smoothed Data		
	<u>Relative</u> <u>Volume</u>	<u>Deviation Factor</u> <u>Z</u>	
9600	0.8132	1.5140	
9400	0.8181	1.4910	
9200	0.8232	1.4690	
9000	0.8289	1.4470	
8973	Reservoir Pressure 0.8293	1.4430	(1)
8800	0.8343	1.4240	
8400	0.8465	1.3790	
8000	0.8602	1.3350	
7600	0.8756	1.2910	
7200	0.8930	1.2480	
6800	0.9128	1.2050	
6400	0.9358	1.1620	
6000	0.9624	1.1210	
5600	0.9939	1.0810	
5530	Dew Point Pressure 1.0000	1.0740	(2)
5200	<u>1.0316</u>		
4800	<u>1.0776</u>		
<u>4400</u>	1.1352		
4000	1.2091		
3600	1.3075		
3200	1.4438		
2800	1.6392		
2400	1.9139		
2000	2.2533		
1600	2.6203		
1200	3.0212		
1000	3.2462		

(1) Gas Expansion Factor = 1.6317 MSCF/BBL

(2) Gas Expansion Factor = 1.3532 MSCF/BBL

Well-A PVT Table 4

RETROGRADE CONDENSATION DURING GAS DEPLETION AT 298 °F
(Constant Volume Depletion) - Well-A

Pressure <i>psig</i>		Retrograde Liquid Volume, <i>(Percent of Hydrocarbon Pore Space)</i>
5530	Dew Point	Nil
5400		0.59
5200		2.03
5000		3.92
4800		5.92
4700	First Depletion Pressure	6.88
3900		12.28
3100		14.20
2300		14.34
1500		13.44
700		11.62
0		8.99

Properties of Zero psig Residual Liquid:

API Gravity	=	41.42 Degrees API @ 60 °F
Density	=	0.8175 gm/cc @ 60 °F
Molecular Weight	=	192

Well-B PVT Table 1

SAMPLING INFORMATION - Well-B**WELL DATA**

Reservoir	Pre-Khuff Jauf, CH-2
Elevation, ft. DF	920
Perforated Interval (OH), ft DF	14503-14630
Completion Depth, ft. OF	Open Hole
Static Bottom-hole Pressure, psig	8505 @ 14565 ft. DE
Reservoir Datum Temperature, °F	305 @ 14566 ft. DF
Static Bottom-hole Temperature, °F	305 @ 14566 ft. DF
Flowing Bottom-hole Pressure, psig	N.A
Flowing Bottom-hole Temperature, °F	N.A
Shut-in Pressure (Wellhead), psig	N.A
Source of Data	Reservoir Engineering

SAMPLING DATA

Sampling Date	July27, 1995
Type of Sample	Recombination(Gas & Condensate)
Sampling Depth, ft. DF	Surface
Flowing Pressure (Wellhead), psig (Tubing)	2924 @ 18.121 MMSCFD gas 5143 SPO Condensate
Flowing Temperature (wellhead), °F	214
Status of Well	Exploratory
Separator Pressure, psig	330
Separator Temperature, CF	155
Separator GOR, SCF/Sep. bbl	3525

Well-B PVT Table 2

HYDROCARBON ANALYSES OF SEPARATOR PRODUCTS AND CALCULATED WELL STREAM - WELL-B

<u>Component</u>	<u>Separator Liquid</u>	<u>Separator Gas</u>		<u>Well Stream</u>	
	<u>Mol%</u>	<u>Mol%</u>	<u>GPM</u>	<u>Mol%</u>	<u>GPM</u>
Nitrogen	0.16	4.19		3.45	
Carbon Dioxide	0.52	3.22		2.73	
Hydrogen Sulfide	0.00	0.00		0.00	
Methane	6.89	69.12		57.71	
Ethane	4.20	12.18	3.257	10.72	2.867
Propane	5.33	6.14	1.689	5.99	1.648
Iso-Butane	1.62	0.93	0.304	1.06	0.347
n-Butane	4.63	1.89	0.596	2.39	0.753
iso-Pentane	2.68	0.46	0.168	0.87	0.318
n-Pentane	3.35	0.43	0.156	0.97	0.351
Hexanes	7.16	0.50	0.204	1.72	0.701
Heptanes	10.36	0.59	0.272	2.38	7.993
Octanes	11.39	0.29	0.148	2.32	
Nonanes	7.05	0.06	0.034	1.34	
Decanes	4.52	0.00	0	0.83	
Undecanes	1.98	0.00	0	0.36	
Dodecanes plus	<u>28.16</u>	<u>0.00</u>	<u>0</u>	<u>5.16</u>	
	100.00	100.00	6.828	100.00	14.978

Properties of Heptanes Plus

API Gravity @ 60°F	42.7	43.8
Density, gm/cc @ 60 °F	0.8115	0.8062
Molecular Weight	168	164.18

Properties of Dodecanes plus

API Gravity @ 60°F	35.7
Density, gm/cc @ 60 °F	0.8455
Molecular Weight	224

Calculated separator gas gravity (air = 1.000) = 0.8199

Calculated gross heating value for separator gas per cubic foot of dry gas @ 14.73 psia and 60 °F = 1273 BTU

Primary separator gas collected @ 1030 psig and 177 °F
 Primary separator liquid collected @ 1030 psig and 177 °F

Primary separator gas / separator liquid ratio = 3525 SCF/BBL @ 330 PSIG & 155°F
 Primary separator gas / well stream ratio = 816.74 MSCF/MMSCF

* GPM value is for C7 plus fraction

Well-B PVT Table 3

DEVIATION FACTOR, "Z"
(Constant Composition Expansion) - Well-B

Pressure psia	Smoothed Data Deviation Factor		
	<u>250 °F</u>	<u>275 °F</u>	<u>305 °F</u>
8,600	1.591	1.569	1.538
8,200	1.525	1.508	1.479
7,800	1.460	1.448	1.420
7,400	1.395	1.388	1.362
7,000	1.331	1.328	1.305
6,600	1.267	1.268	1.249
6,200	1.205	1.210	1.194
5,800	1.144	1.151	1.141
5,400	1.084	1.095	1.089
5,000	1.027	1.040	1.039
4,600	0.973	0.987	0.992

Dew Point Pressure Data

4,496	0.960	-	-
4,518	-	0.977	-
4,521	-	-	0.983

Well-B PVT Table 4

RETROGRADE CONDENSATION DURING GAS DEPLETION AT 305 ° F
(Constant Volume Depletion) - Well-B

Pressure <i>psig</i>		Retrograde Liquid Volume, <i>(Percent of Hydrocarbon Pore Space)</i>
4506	Dew Point	Nil
4400		20.15
4200		28.84
4000		31.22
3800	First Depletion Pressure	32.02
3200		31.73
2600		30.30
2000		28.53
1400		26.49
700		23.43
0		17.76

Properties of Zero psig Residual Liquid:

API Gravity	=	41.63 Degrees API @ 60 °F
Density	=	0.8165 gm/cc @ 60 °F
Molecular Weigh	=	179

Well-C PVT Table 1

SAMPLING INFORMATION - Well-C**WELL DATA**

Reservoir	JAUf, PT-1, FLOW-3
Elevation, ft. DF	878
Perforated Interval (OH), ft DF	14871-14573
Completion Depth, ft. OF	N.A.
Static Bottom-hole Pressure, psig	8800 @ 14700 ft. DE
Reservoir Datum Temperature, °F	305 @ 14700 ft. DF
Static Bottom-hole Temperature, °F	305 @ 14700 ft. DF
Flowing Bottom-hole Pressure, psig	N.A.
Flowing Bottom-hole Temperature, °F	305
Shut-in Pressure (Wellhead), psig	N.A
Source of Data	Reservoir Engineering

SAMPLING DATA

Sampling Date	November 14, 1996
Type of Sample	Recombination(Gas & Condensate)
Sampling Depth, ft. DF	Surface
Flowing Pressure (Wellhead), psig (Tubing)	4480 @ 4.2 MMSCFD gas 677 BPD Condensate
Flowing Temperature (wellhead), °F	138
Status of Well	Delineation well
Separator Pressure, psig	270
Separator Temperature, CF	66
Separator GOR, SCF/Sep. bbl	6206

Well-C PVT Table 2

**HYDROCARBON ANALYSES OF SEPARATOR PRODUCTS AND CALCULATED
WELL STREAM - WELL-C**

<u>Component</u>	<u>Separator Liquid</u>		<u>Separator Gas</u>		<u>Well Stream</u>	
	<u>Mol%</u>		<u>Mol%</u>	<u>GPM</u>	<u>Mol%</u>	<u>GPM</u>
Nitrogen	0.25		3.50		3.12	
Carbon Dioxide	0.85		3.55		3.23	
hydrogen Sulfide	0.00		0.00		0.00	
Methane	8.36		78.01		69.76	
Ethane	5.65		9.48	2.535	9.03	2.415
Propane	7.19		3.59	0.988	4.02	1.106
Iso-Butane	2.68		0.56	0.183	0.81	0.265
n-Butane	6.00		0.83	0.262	1.44	0.454
iso-Pentane	3.66		0.19	0.070	0.60	0.220
n-Pentane	3.72		0.13	0.047	0.55	0.199
Hexanes	7.56		0.07	0.029	0.96	0.391
Heptanes	9.11		0.04	0.018	1.11	4.753
Octanes	10.41		0.04	0.020	1.27	
Nonanes	7.16		0.01	0.006	0.86	
Decanes	5.16		0.00	0.000	0.61	
Undecanes	2.44		0.00	0.000	0.29	
Dodecanes plus	19.80		0.00	0.000	2.34	
	100.00		100.00	4.158	100.00	9.803

Properties of Heptanes Plus

API Gravity @ 600F	4204	42.6
Density, gm/cc @ 60 °F	0.813	0.8121
Molecular Weight	189	188

Properties of Dodecanes plus

API Gravity @ 600F	35.7
Density, gm/cc @ 60 °F	0.8456
Molecular Weight	252

Calculated separator gas gravity (air = 1.000) = 0.7141

Calculated gross heating value for separator gas
per cubic foot of dry gas @ 14.73 psia and 60 °F = 1112 BTU

Primary separator gas collected @ 1030 psig and 177 °F
Primary separator liquid collected @ 1030 psig and 177 °F

Primary separator gas / separator liquid ratio = 6206 SCF/BBL @ 330 PSIG & 155 °F
Primary separator gas / well stream ratio = 881.7 MSCF/MMSCF

* GPM value is for C7 plus fraction

Well-C PVT Table 3

DEVIATION FACTOR, "Z"
(Constant Composition Expansion) - Well-C

Pressure		Smoothed Data	
<u>psia</u>		<u>Deviation Factor</u>	
		<u>305 °F</u>	
9000		1.406	
8800	Reservoir Pressure	1.386	(1)
8000		1.307	
7800		1.287	
7600		1.267	
7400		1.248	
7200		1.228	
7000		1.209	
6800		1.190	
6600		1.171	
6400		1152.000	
6200		1.133	
6000		1.115	
5973	Dew Point Pressure	1.112	(2)

(1) Gas Expansion Factor = 1.6448 MSCF/BBL

(2) Gas Expansion Factor = 1.3913 MSCF/BBL

Well-C PVT Table 4

RETROGRADE CONDENSATION DURING GAS DEPLETION AT 305 °F
(Constant Volume Depletion) - Well-C

Pressure <i>psig</i>	Retrograde Liquid Volume, <i>(Percent of Hydrocarbon Pore Space)</i>
5973	DIEW POINT
5900	Nil
5800	0.01
5600	0.08
5400	0.65
5200	1.55
5000	2.64
4800	3.83
4600	5.02
4400	6.16
4200	7.22
4000	8.16
3600	8.98
3200	10.24
2800	11.05
2400	11.52
2000	11.73
1600	11.74
1200	11.57
800	11.20
400	10.60
0	9.78
0	8.87

Properties of Zero psig Residual Liquid:

API Gravity	=	39.79 Degrees API @ 60 °F
Density	=	0.8253 gm/cc @ 60 °F
Molecular Weight	=	151

Well-D PVT Table 1

SAMPLING INFORMATION - Well-D**WELL DATA**

Reservoir	Pre Khuff, Jauf
Elevation, ft. DF	925
Perforated Interval (OH), ft DF	14236-14640
Completion Depth, ft. OF	14770
Static Bottom-hole Pressure, psig	8790 @ 14236 ft. DE
Reservoir Datum Temperature, °F	301 @ 14236 ft. DF
Static Bottom-hole Temperature, °F	301 @ 13068 ft. DF
Flowing Bottom-hole Pressure, psig	7631
Flowing Bottom-hole Temperature, °F	301
Shut-in Pressure (Wellhead), psig	5320
Source of Data	Reservoir Engineering

SAMPLING DATA

Sampling Date	April 19, 1997
Type of Sample	Recombination(Gas & Condensate)
Sampling Depth, ft. DF	Surface
Flowing Pressure (Wellhead), psig (Tubing)	4905 @ 9.69 MMSCFD Gas 1931 BPD Condensate
Flowing Temperature (wellhead), °F	173
Status of Well	Exploration
Separator Pressure, psig	578
Separator Temperature, CF	125
Separator GOR, SCF/Sep. bbl	5018

Well-D PVT Table 2

**HYDROCARBON ANALYSES OF SEPARATOR PRODUCTS AND CALCULATED
WELL STREAM - WELL-D**

<u>Component</u>	<u>Separator Liquid</u>		<u>Separator Gas</u>		<u>Well Stream</u>	
	<u>Mol%</u>		<u>Mol%</u>	<u>GPM</u>	<u>Mol%</u>	<u>GPM</u>
Nitrogen	0.22		4.07		3.49	
Carbon Dioxide	0.90		3.02		2.70	
hydrogen Sulfide	0.00		0.00		0.00	
Methane	12.45		74.36		65.07	
Ethane	7.13		11.09	2.965	10.50	2.808
Propane	7.51		4.52	1.243	4.97	1.367
Iso-Butane	2.31		0.71	0.232	0.95	0.311
n-Butane	5.63		1.22	0.384	1.87	0.589
iso-Pentane	3.19		0.34	0.124	0.77	0.282
n-Pentane	3.59		0.29	0.105	0.78	0.283
Hexanes	7.11		0.22	0.090	1.25	0.510
Heptanes	9.24		0.12	0.055	1.49	4.979
Octanes	10.19		0.04	0.020	1.56	
Nonanes	7.17		0.00	0.000	1.08	
Decanes	5.19		0.00	0.000	0.78	
Undecanes	2.53		0.00	0.000	0.38	
Dodecanes plus	15.74		0.00	0.000	2.36	
	100.10		100.00	5.218	100.00	11.129

Properties of Heptanes Plus

API Gravity @ 600F	44.3	42.6
Density, gm/cc @ 60 °F	0.8041	0.8121
Molecular Weight	166	188

Properties of Dodecanes plus

API Gravity @ 600F	35.9
Density, gm/cc @ 60 °F	0.8445
Molecular Weight	257

Calculated separator gas gravity (air = 1.000) = 0.7475

Calculated gross heating value for separator gas
per cubic foot of dry gas @ 14.73 psia and 60 °F = 1168 BTU

Primary separator gas collected @ 1030 psig and 177 °F
Primary separator liquid collected @ 1030 psig and 177 °F

Primary separator gas / separator liquid ratio = 5018 SCF/BBL @ 578 PSIG & 125 °F
Primary separator gas / well stream ratio = 850.05 MSCF/MMSCF

* GPM value is for C7 plus fraction

Well-D PVT Table 3

DEVIATION FACTOR, "Z"
(Constant Composition Expansion) - Well-D

Pressure		Smoothed Data	
<u>psia</u>		<u>Deviation Factor</u>	
		<u>301 °F</u>	
9000		1.495	
8790	Reservoir Pressure	1.470	(1)
8000		1.379	
7600		1.328	
7200		1.281	
6800		1.235	
6400		1.188	
6000		1.143	
5600		1.098	
5200		1.055	
5138	Dew Point Pressure	1.048	(2)

(1) Gas Expansion Factor = 1.6448 MSCF/BBL

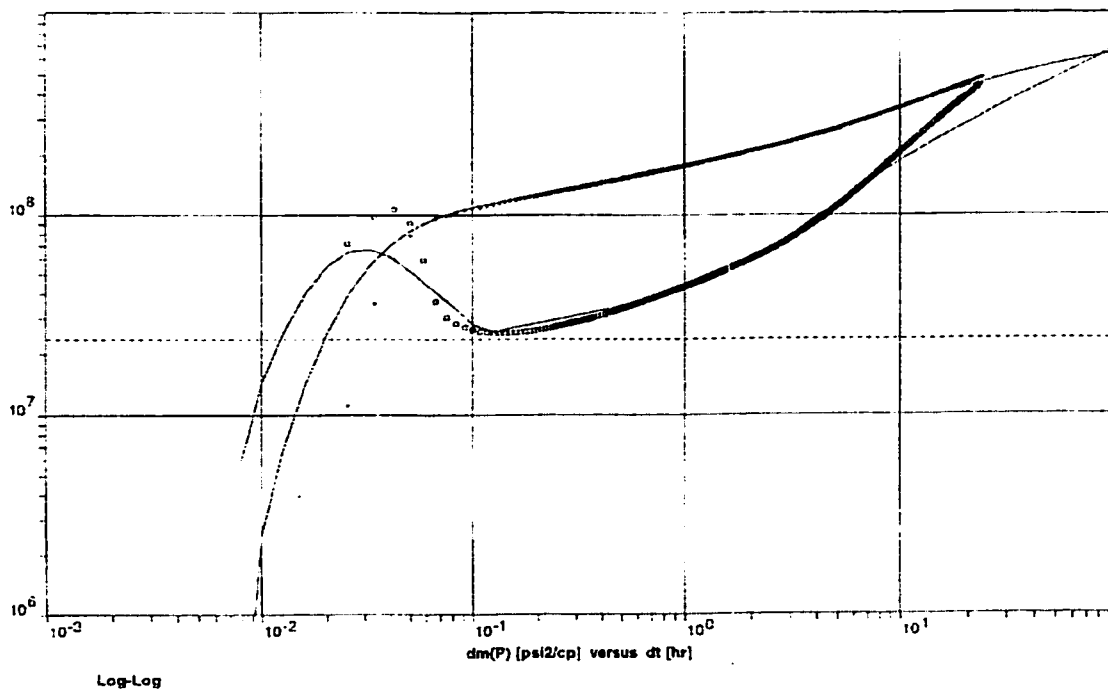
(2) Gas Expansion Factor = 1.3913 MSCF/BBL

Well-D PVT Table 4

RETROGRADE CONDENSATION DURING GAS DEPLETION AT 305 ° F
(Constant Volume Depletion) - Well-D

Pressure <i>psig</i>		Retrograde Liquid Volume, <i>(Percent of Hydrocarbon Pore Space)</i>
5138	DIEW POINT	Nil
5000		0.73
4800		3.85
4600		7.32
4400		10.12
4200		12.11
4000		13.49
3800		14.48
3600		15.25
3200		16.38
2800		17.02
2400		17.17
2000		16.93
1600		16.38
1200		15.49
800		14.30
400		12.96
0		11.30

Well-D Build-up Data



The above Derivative plot for Well-D build-up data indicates that the data have been influenced by reservoir heterogeneities.

Well-E PVT Table 1

SAMPLING INFORMATION - Well-E**WELL DATA**

Reservoir	JAUF, CH-1
Elevation, ft. DF	1037
Perforated Interval (OH), ft DF	12809-12989
Completion Depth, ft. OF	13340
Static Bottom-hole Pressure, psig	8600 @ 12900 ft.DF
Reservoir Datum Temperature, °F	283 ~ 12900 ft. CF
Static Bottom-hole Temperature, °F	283 @ 12900 ft. DF
Flowing Bottom-hole Pressure, psig	8480
Flowing Bottom-hole Temperature, °F	283
Shut-in Pressure (Wellhead), psig	N.A
Source of Data	Reservoir Management Dept.

SAMPLING DATA

Sampling Date	June 01, 1998
Type of Sample	Recombination(Gas & Condensate)
Sampling Depth, ft. DF	Surface
Flowing Pressure (Wellhead), psig (Tubing)	5978 @ 16.17 MMSCFD Gas 737 BPD Condensate
Flowing Temperature (wellhead), °F	150
Status of Well	Delineation well
Separator Pressure, psig	536
Separator Temperature, CF	70
Separator GOR, SCF/Sep. bbl	21940

Well-E PVT Table 2

**HYDROCARBON ANALYSES OF SEPARATOR PRODUCTS AND CALCULATED
WELL STREAM - WELL-E**

<u>Component</u>	<u>Separator Liquid</u>		<u>Separator Gas</u>		<u>Well Stream</u>	
	<u>Mol%</u>		<u>Mol%</u>	<u>GPM</u>	<u>Mol%</u>	<u>GPM</u>
Nitrogen	0.31		3.58		3.45	
Carbon Dioxide	0.98		2.87		2.79	
Hydrogen Sulfide	0.00		0.00		0.00	
Methane	15.90		80.65		77.98	
Ethane	8.40		8.86	2.369	8.84	2.363
Propane	7.76		2.67	0.735	2.88	0.791
Iso-Butane	2.92		0.46	0.150	0.56	0.183
n-Butane	5.14		0.56	0.176	0.75	0.236
iso-Pentane	3.57		0.17	0.062	0.31	0.113
n-Pentane	2.72		0.10	0.036	0.21	0.076
Hexanes	6.53		0.05	0.020	0.32	0.130
Heptanes	8.04		0.01	0.005	0.34	1.235
Octanes	9.04		0.01	0.005	0.38	
Nonanes	6.60		0.01	0.006	0.28	
Decanes	4.61		0.00	0.000	0.19	
Undecanes	3.08		0.00	0.000	0.13	
Dodecanes plus	14.40		0.00	0.000	0.59	
	100.00		100.00	3.584	100.00	5.127

Properties of Heptanes Plus

API Gravity @ 600F	45.6	45.9
Density, gm/cc @ 60 °F	0.7981	0.797
Molecular Weight	156	155

Properties of Dodecanes plus

API Gravity @ 600F	37.7
Density, gm/cc @ 60 °F	0.8356
Molecular Weight	245

Calculated separator gas gravity (air = 1.000) = 0.6875

Calculated gross heating value for separator gas
per cubic foot of dry gas @ 14.73 psia and 60 °F = 1087 BTU

Primary separator gas collected @ 1030 psig and 177 °F
Primary separator liquid collected @ 1030 psig and 177 °F

Primary separator gas / separator liquid ratio = 21940 SCF/BBL @ 536 PSIG & 70 °F
Primary separator gas / well stream ratio = 959.07 MSCF/MMSCF

* GPM value is for C7 plus fraction

Well-E PVT Table 3

DEVIATION FACTOR, "Z"
(Constant Composition Expansion) - Well-E

Pressure		Smoothed Data	
<u>psia</u>		<u>Deviation Factor</u>	
		<u>283 °F</u>	
9000		1.370	
8600	Reservoir Pressure	1.334	(1)
8000		1.283	
7800		1.266	
7600		1.249	
7400		1.232	
7000		1.199	
6800		1.182	
6400		1.151	
6000		1.120	
5522	Dew Point Pressure	1.084	(2)

(1) Gas Expansion Factor = 1.7193 MSCF/BBL

(2) Gas Expansion Factor = 1.3585 MSCF/BBL

Well-E PVT Table 4

RETROGRADE CONDENSATION DURING GAS DEPLETION AT 283 ° F
(Constant Volume Depletion) - Well-E

Pressure <i>psig</i>		Retrograde Liquid Volume, <i>(Percent of Hydrocarbon Pore Space)</i>
5522	DEW POINT	NIL
5500		0.01
5400		0.05
5200		0.12
5000		0.20
4800		0.28
4600		0.36
4400		0.45
4200		0.54
4000		0.64
3600		0.85
3200		1.10
2800		1.39
2400		1.69
2000		1.95
1600		2.12
1200		2.18
800		2.16
400		2.05
0		1.90

Properties of Zero psig Residual Liquid:

API Gravity	=	40.7 Degrees API @ 60 °F
Density	=	0.8208 gm/cc @ 60 °F
Molecular Weight	=	207

NOMENCLATURE

c = Number of components.

\underline{E} = Internal energy, BTU

E_k = Partial molal internal energy, $\left(\frac{\partial \underline{E}}{\partial m_k}\right)_{T,P,m_i}$, BTU per mole.

\underline{F} = Thermodynamic potential or free energy, $\underline{E} + P\underline{V} - T\underline{S}$, BTU

F_k^* = Molal thermodynamic potential of component k in the pure state at infinite attenuation.

F_k = Chemical potential or partial molal free energy $\left(\frac{\partial \underline{F}}{\partial m_k}\right)_{T,P,m_i}$ BTU per mole.

f = Fugacity

f_d = Degree of freedom

h = Elevation above an arbitrarily chosen datum, feet.

M = Average molecular weight.

M_k = Molecular weight of component k

m_k = Moles of component k

n = Mole fraction of any component

n_k = Mole fraction of component k

P = Pressure, psia

p = Number of phases

R = Universal gas constant

\underline{S} = Entropy, BTU per deg. F. absolute.

S_k = Partial molal entropy of component k ; $\left(\frac{\partial \underline{S}}{\partial m_k}\right)_{T,P,m}$; BTU per deg. F.

absolute per mole.

T = Temperature (thermodynamic scale), deg. F. absolute.

\underline{V} = Volume, cu. ft.

V = Molal volume, cu. ft. per mole

\bar{V}_k = Partial molal volume $\left(\frac{\partial V}{\partial m_k}\right)_{T,P,m}$, cu. ft. per mole

\bar{V}'_k = Residual partial molal volume $\left(\frac{\partial \underline{V}}{\partial m_k}\right)_{T,P,m}$, cu. ft. per mole

ω' = Work done by the system during an infinitesimal change in state, exclusive of that resulting from a change in volume, BTU.

Subscript a denotes all components in an n component system.

Subscript k denotes any component from 1 to n .

Subscript i denotes all components except component k .

Subscript j denotes any components except component k and n .

Subscript m denotes all components except component k and n .

Subscript q denotes all components except component j and n .

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