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A COMPARISON OF TWO-PHASE INFLOW PERFORMANCE RELATIONSHIPS

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ABSTRACT

In this research, the individual performance of vertical oil wells are investigated. The objective of this study was to verify the suitability of certain empirical relations to predict the rate-pressure behavior of a single oil well producing from solution-gas drive reservoirs.

Inflow performance curves were generated for 26 cases based on actual field data. The predicted rates where then compared to actual measured rate and pressure data. The variation between the measured and predicted rates by the various methods studied has been analyzed.

Based on this analysis, multipoint performance methods generally provide the most reliable estimates of well performance. Fetkovich's multipoint method was the most consistent performance predictionfor the cases studied. In addition, it was observed that no one method presented the best results for all cases and it is recommended that multipoint performance methods be utilized to yield a range of potential pressure-production behavior.

CHAPTER 1

INTRODUCTION

Reservoirs are investigated for exploration around the world. As the reserves of oil or gas are produced, petroleum companies are exploring places which are increasingly difficult and costly to access. If companies want to develop a venture in such areas, it must make sure the potential of such a reservoir would at least cover the investment needed for the enterprise. Millions of dollars are at stake, so a slight misevaluation could result in a catastrophic venture.

For this reason it is important to estimate a well's deliverability at the beginning of field development. Consequently, an important role of the petroleum engineer is to predict the performance of individual wells. Estimates of well performance allows the engineer to evaluate various operating conditions and determine the optimum production scheme and design production and artificial lift equipment when necessary. They can also be used to design and evaluate the effects of stimulation treatments. In addition, estimates of future performance can be made from this information for forecasting and planning purposes. It is therefore of important to estimate the pressure-production behavior of a well. This thesis will review and compare various methods that have been proposed in the literature for describing individual well performance in solution-gas drive reservoirs.

1.1 Research Objectives

During the past sixty years, a number of relations have been proposed for the prediction of well performance at present and future time. Some are based on simulator results which were used to develop relationships while others were developed from field observations. Each method has advantages, disadvantages and limitations. The objectives of this research are to: (1) review well performance prediction methods, (2) apply these methods using field data, and, (3) evaluate and compare the methods.

The objectives would be readily achieved if one could obtain actual well data as easy as changing parameters during computer simulation runs. However, this is not the case and for this study to be meaningful, field data had to be obtained. The data utilized has been reported in the petroleum engineering literature and will be used in this analysis. While the data may appear limited, it covers a range of solution-gas drive reservoirs where the reservoir pressure is below its bubble point pressure. This data will provide a qualitative evaluation of the various well performance methods reviewed in this study.

1.2 Background

The productivity of a well should be an indication or measure of the producing rate of the reservoir within the drainage radius of the well. The methods of measuring productivity are many and varied depending on the operator and type of well. The method most commonly used at the beginning of this century was the open-flow potential through the casing. This method gradually lost favor, as it was wasteful, expensive, and, frequently, quite detrimental to the well and reservoir. Open-flow tests were not a true indicator of the comparative ability of the formation to yield oil, due to the wide variance in equipment, such as casing size, wellhead, separators, etc. While using this technique operators felt compelled to complete the well with equipment so that it was assured the maximum potential was reached, which increased well costs. In addition, the high rate of production during open-flow potential tests greatly reduced the bottomhole pressure, often causing formation damage and premature water encroachment which resulted in lower recovery of oil and higher lifting costs.[1]

Petroleum engineers were aware of this, and in the 1920's, the use of a restricted potential became popular throughout the industry. The restricted potential could be taken through the casing using a uniform size choke at the casinghead. A relationship would be established between the open-flow and tubing potentials with the open-flow potential determined indirectly thereafter from the use of the tubing potential. Tubing potential was an improvement over open-flow potential but still had the disadvantage of comparing well-to-well derivability due to the inability of each well to demonstrate its full capacity. This was indicated by the fact that a large proportion of wells show approximately the same potential although differences in their flowing pressures indicated the ability of some to produce was greater than others.[1]

In 1930, Moore[1] suggested a new method of determining the relative productivity of a well without an open-flow test. This method involved the measurement of the static bottomhole pressure and the flowing bottomhole pressure at various rates of production. This measure of the ability of a well to produce was termed its productivity index (PI), which is the ratio of the production rate to the differential between the static and flowing bottomhole pressures

$$J = \frac{q}{p_r - p_{wf}} \qquad (1)$$

As shown in Eq. 1, the PI is an indication of the ability of the reservoir to produce formation fluids to the wellbore as it does not take into account the resistance of the flow string, but measures only the resistance of flow through the porous media.

The PI can be developed from Darcy's relationship for single-phase, incompressible flow and relates the rate-pressure function to reservoir parameters

$$J = \frac{q_o}{p_r - p_{wf}} = \frac{2\pi hk}{B_o \mu_o (\ln(r_e / r_w) - 0.5)} \tag{2}$$

In 1936 Rawlins and Schellhardt[2] proposed an empirical relation to estimate deliverability for gas wells based on multirate test data. Their relationship was

$$q_g = C(p_r^2 - p_{wf}^2)^n \tag{3}$$

The relationship was developed after interpreting several hundred multirate gas well tests. A linear trend was observed on a log-log plot of flow rate versus the difference in the squares of the reservoir pressure and the flowing wellbore pressure. Extrapolation of this line enabled the maximum possible flow rate to be estimated from the graph as presented Fig 1.1. This maximum rate was termed the absolute open flow (AOF). In the equation written above, *n* is the reciprocal of the slope of the line on the log-log plot.

As mentioned earlier, Darcy's relation is applicable for single-phase flow. In 1942 Evinger and Muskat[3] pointed out that a straight line PI should not be valid when

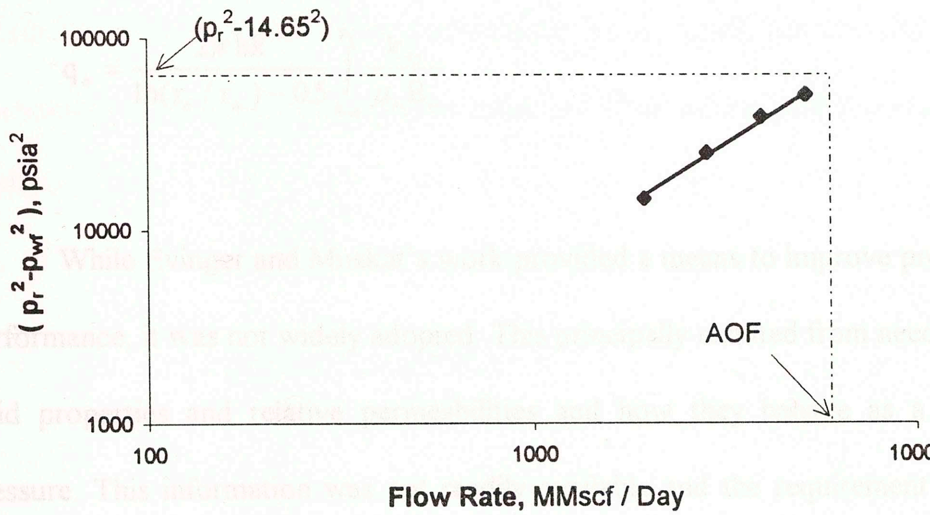

Fig. 1.1- Back-pressure curve for a gas well.

multiphase flow occurs in the reservoir. Multiphase flow can result when the reservoir pressure or the flowing bottomhole pressure is below the bubble point pressure of the oil resulting in liquid and vapor flowing in the reservoir. Most oil wells will produce under multiphase flow conditions for part, if not the majority, of their producing lives. They presented theoretical results which lead to the conclusion that the relationship between flow rate and pressure has a curved shape rather than a straight line when two phases are flowing. Their relationship is:

$$q_o = \frac{2\pi hk}{\ln(r_e / r_w) - 0.5} \int_{p_{wf}}^{p_r} \frac{k_{ro}}{\mu_o B_o} \tag{4}$$

While Evinger and Muskat's work provided a means to improve predicting well performance, it was not widely adopted. This principally resulted from needing to know fluid properties and relative permeabilities and how they behave as a function of pressure. This information was not readily available and the requirement to integrate the relationship made it difficult for the petroleum engineer to implement in a ready manner.

1.3 Two-phase IPRs

The birth of the computer industry opened a new horizon for petroleum engineers. Since then, the size and capacity of computers have been respectively reduced and augmented by orders of magnitude. The petroleum engineer quickly embraced the technology, and as soon as 1960 some pioneers in computer programming like Weller[4] developed programs and numerical solutions from which they computed the saturation and pressure profile within the reservoir.

Vogel[5], in 1968, was able to generate an empirical relation for solution-gas drive reservoir based on simulation results using Weller's algorithm. Vogel noticed that the shape of the pressure-rate curves for a wide range of rock and fluid properties were very similar. He had the brilliant idea to make the plot dimensionless, and observed the individual curves collapsed to a small band (Fig. 1.2). Vogel divided the pressure at each point by the reservoir pressure and the flow rate by the maximum flow rate to obtain the dimensionless inflow performance curve. Using his data he developed a relationship to describe the observed behavior. This inflow performance relationship (IPR) is

$$\frac{q_o}{q_{o\,max}} = 1 - 0.2\left(\frac{p_{wf}}{p_r}\right) - 0.8\left(\frac{p_{wf}}{p_r}\right)^2 \qquad (5)$$

Vogel's IPR obtained almost immediate acceptance by the petroleum industry due to the ease of use and the minimal test information needed. The most important limitation of his contribution was that field verification was missing. However, his relation is commonly used in the industry today which demonstrates its applicability in the field.

By comparing the performance curves of liquid, gas, and two-phase flow shown in Fig 1.3, Fetkovich[6] observed the two-phase curve was closer to the gas curve rather

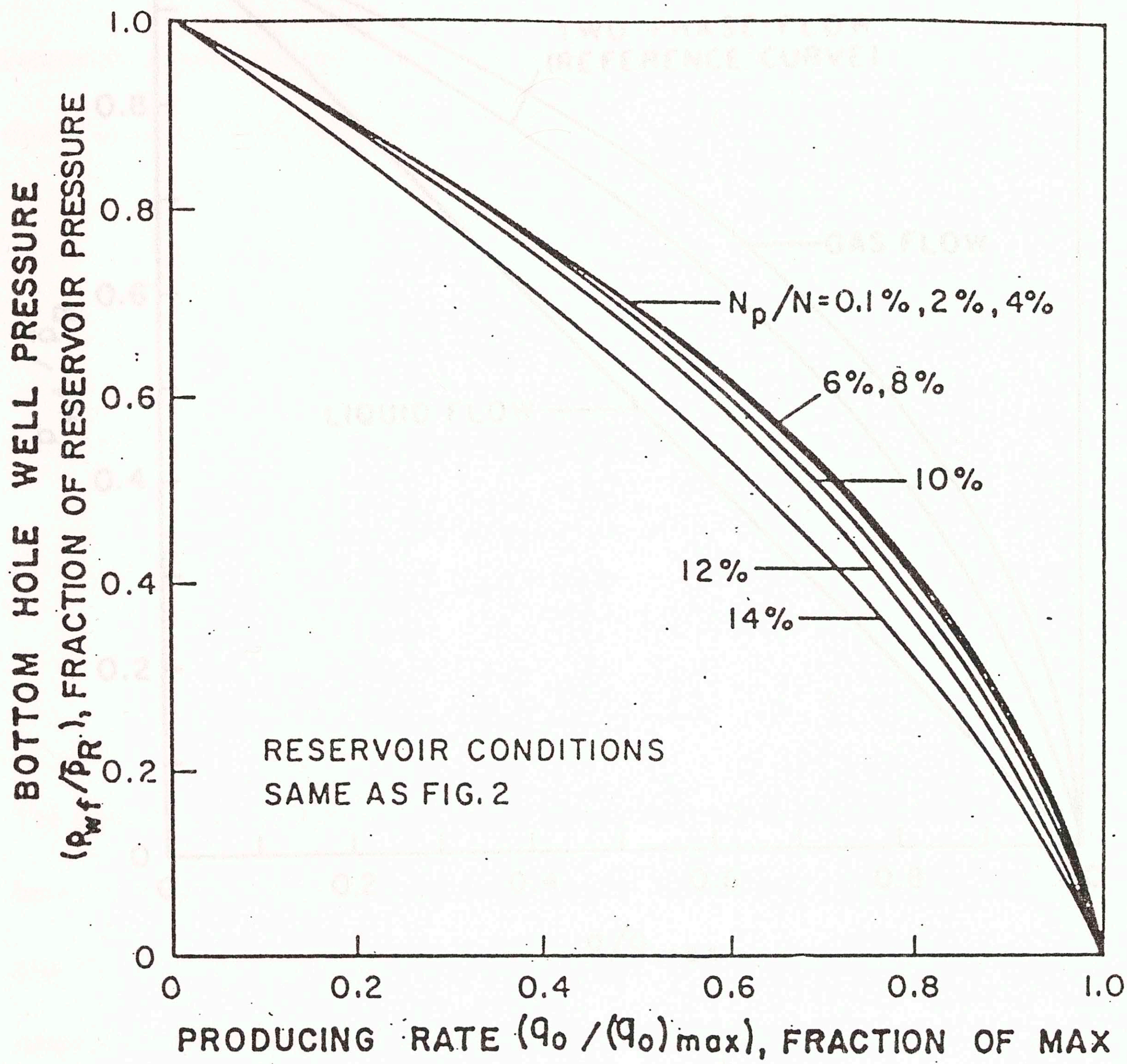

Fig 1.2 - Vogel's Dimensionless Inflow Performance Relationship (from Ref. 5).

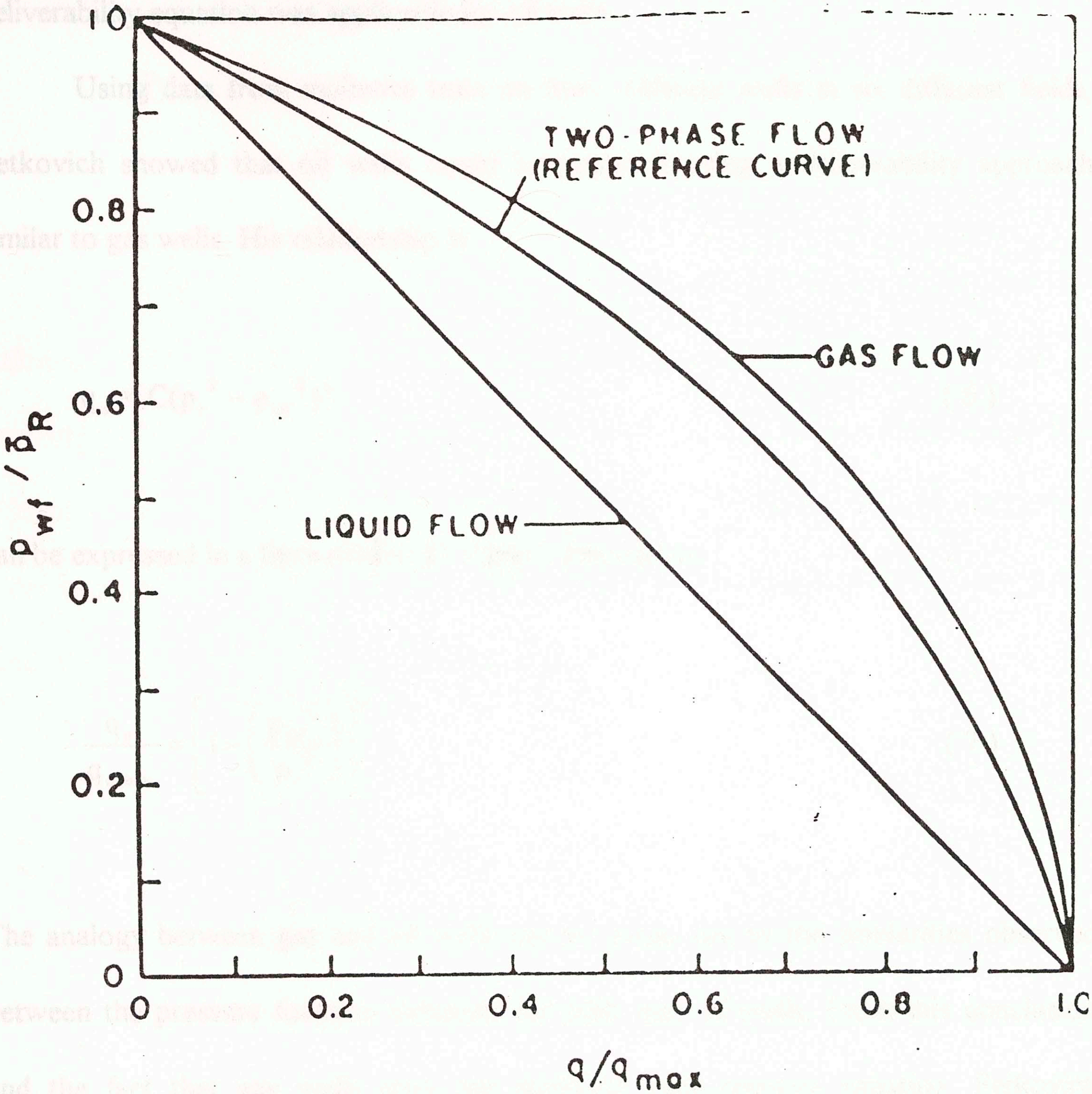

Fig. 1.3 - Comparison of IPRs for liquid, gas and two-phase flow (from Ref. 5).

than to the liquid curve. From this, he proposed Rawlins and Schellhardt's gas well deliverability equation was applicable for oil wells.

Using data from multirate tests on forty different wells in six different fields, Fetkovich showed that oil wells could be analyzed using a deliverability approach similar to gas wells. His relationship is

$$q_o = C(p_r^2 - p_{wf}^2)^n \qquad (6)$$

can be expressed in a form similar to Vogel's relation as:

$$\frac{q_o}{q_{o\,max}} = \left[1 - \left(\frac{p_{wf}^2}{p_r^2}\right)\right]^n \qquad (7)$$

The analogy between gas and oil wells can be made due to the similarities observed between the pressure function behavior for both type of wells. From this conclusion and the fact that gas wells obey the empirical back-pressure equation, Fetkovich suspected and proved that it should be the same for oil wells.

Fetkovich's field verifications provided solid support for his IPR method and it was quickly accepted in the industry. His method, unfortunately, requires a multipoint test to be able to determine the exponent *n*. To overcome this limitation, his method has been modified to assume *n* is equal to unity when multipoint test data are unavailable.

completion effectiveness. Using Forchheimer's[8] model to describe non-Darcy flow, they proposed the following relationship between pressure and rate.

$$\frac{p_r - p_{wf}}{q_o} = C + Dq_o \qquad (8)$$

From this equation it is evident that a cartesian plot of the ratio of the pressure difference to flow rate versus the flow rate yields a straight line with a slope *D* and an intercept *C*. The term *C* in the equation is called the laminar flow coefficient, and *D* is referred to as the turbulence coefficient. This approach requires a multipoint test in order to determine *C* and *D*. Once these two terms are estimated, the flow rate at any other flowing pressure can be determined from

$$q_o = \frac{-C + \sqrt{C^2 + 4D(p_r - p_{wf})}}{2D} \qquad (9)$$

A major contribution of this work is the ability to evaluate completion effectiveness based on the turbulence coefficient, *D*. The authors presented relations for *C* and *D* which can be compared to values from the test data, these relations are

$$C = \frac{\mu B_o}{1.127E-3(2\pi kh)}\left\{\ln\left(0.47\frac{r_e}{r_w}\right) + S\right\} \qquad (10)$$

and

and

$$D = \frac{(9.08E-13)\beta\ B_o^{\ 2}\rho}{4\pi^2 h^2 r_w} \qquad (11)$$

By knowing D for a certain set of completion parameters, one can determine D after a change. For example, it can be used to evaluate the effect of flow through a gravel pack or along a fracture or a change in perforation density. It is important from a production standpoint to know the effectiveness of the well completion. A series of very short tests may be sufficient for this purpose where otherwise a long term build-up test may be required. Thus, knowing the laminar and turbulence coefficients may help for the purpose of enhancing the productivity of a well.

Based on Vogel's work, Klins and Majcher[9] developed a new inflow performance relationship incorporating the bubble point pressure. The authors used a computer simulation program and simulated twenty-one wells which lead to 1,344 IPR curves. Using a non-linear regression package to analyze their data, they presented the following IPR.

$$\frac{q_o}{q_{o\,max}} = 1 - 0.295\left(\frac{p_{wf}}{p_r}\right) - 0.705\left(\frac{p_{wf}}{p_r}\right)^d \qquad (12)$$

where

$$d = \left[0.28 + 0.72\frac{p_r}{p_b}\right](1.235 + 0.001 p_b) \qquad (13)$$

The proposed equation is not quadratic with respect to pressure but include a new exponent *d* which is a function of the bubble point pressure.

A limitation of this work is that it is based on a computer simulation study, which is only as good as the assumptions made to build the model. In addition, to utilize the relationship, one needs the estimate value of the bubble point pressure. This pressure is not always available and one would have to rely on correlations to estimate this value.

Sukarno[10] developed an IPR that takes into account for the variation of the flow efficiency when the flowing bottomhole pressure changes. He attempted to describe the flow restriction due to increasing gas saturation around the wellbore as the pressure drawdown increases, the so called rate and time dependent skin, S(q,t). Using a single well, three-phase simulator and a definition of flow efficiency as a ratio of the productivity index at actual conditions to ideal conditions, Sukarno developed by non-linear regression analysis the following formula

$$\frac{(q_o)_{actual}}{q_{o,max@S=0}} = FE\left\{1-0.1489\left(\frac{p_{wf}}{p_r}\right)-0.4418\left(\frac{p_{wf}}{p_r}\right)^2-0.4093\left(\frac{p_{wf}}{p_r}\right)^3\right\} \qquad (14)$$

where

$$FE = \left\{a_o + a_1\left(\frac{p_{wf}}{p_r}\right)+a_2\left(\frac{p_{wf}}{p_r}\right)^2+a_3\left(\frac{p_{wf}}{p_r}\right)^3\right\} \qquad (15)$$

and

$$a_n = b_o + b_1 S + b_2 S^2 + b_3 S^3 \qquad (16)$$

The values of Eq. 16 are given in Table 1.1.

1.4 Future Performance Relationships

In parallel to the development of the IPR, the engineer desires to estimate the pressure-production behavior as the reservoir pressure declines from the test condition. Standing[11] was one of the first to look at predicting future performance from an IPR. He defined a new parameter J^* which is a modified PI when the flowing pressure converges to the static pressure. The problem with his method was that reservoir fluid properties needed to be calculated at present and future time. He presented the following relationship to predict the future J_f^*

$$\frac{J_f^*}{J_p^*} = \frac{\left(k_{ro} / \mu_o B_o \right)_f}{\left(k_{ro} / \mu_o B_o \right)_p} \qquad (17)$$

where

$$J_p^* = \frac{1.8 q_o}{p_r \left(1.0 - 0.2 \left(p_{wf} / p_r \right) - 0.8 \left(p_{wf} / p_r \right)^2 \right)} \qquad (18)$$

The difficulties in estimating saturations and relative permeabilities at present and future conditions limits the application of Standing's method in practice.

Table 1.1 - Constants for Eq. 16

	b_0	b_1	b_2	b_3	r^2
a_0	1.03940	0.12657	0.01350	-0.00062	0.9995
a_1	0.01668	-0.00385	0.00217	-0.00010	0.9911
a_2	-0.0858	0.00201	-0.00456	0.00020	0.9958
a_3	0.00952	-0.00391	0.00190	-0.00001	0.9973

Fetkovich[6] commented on future performance prediction and anticipated the J^* ratio proposed by Standing could be estimated by a linear relationship of the reservoir pressure ratio. From this idea he proposed an equation to permit the calculation of the future maximum rate. The relation is

$$\frac{q_{o,max,f}}{q_{o,max,p}} = \frac{p_{r,f}}{p_{r,p}} \left[\frac{p_{r,f}^{\;2}}{p_{r,p}^{\;2}} \right]^n \qquad (19)$$

The main advantage of his relation is that it does not require any more information than what was needed for the inflow performance relation. The major drawback is the assumption that the exponent *n* and the coefficient *C* stay the same at the future time.

Uhri and Blount[12] suggested a "pivot point" method based on two flow tests conducted at two different reservoir pressures. From the slopes at the two end points computed using Vogel's relation, one can draw two lines and the intersection point is called the pivot point. The future IPR curves can be predicted by assuming that all lines will intersect at the same point. The method can be used graphically or numerically. Mathematically, the future maximum flow rate can be calculated from the following equations.

$$q_{o,max,f} = \frac{Ap_{r,f}^{\;2}}{p_{r,f} + n} \qquad (20)$$

where

$$A = \frac{p_{r1} - p_{r2}}{\dfrac{p_{r1}^2}{q_{o,max,1}} - \dfrac{p_{r2}^2}{q_{o,max,2}}} \qquad (21)$$

and

$$n = p_{r1}\left[\frac{Ap_{r1}}{q_{o,max,1}} - 1\right] \qquad (22)$$

In 1985 Kelkar and Cox[13] presented new equations which required two sets of data at two different pressures. Eqs. 23 through 26 present their method where any IPR can be used to determine the maximum flow rate.

$$q_{o,max,f} = A'p_{r,f}^3 + B'p_{r,f} \qquad (23)$$

where

$$J^* = \frac{q_{o,max}}{p_r} \qquad (24)$$

and

$$A' = \frac{J_1^* - J_2^*}{p_{r1}^2 - p_{r2}^2} \qquad (25)$$

and

$$B' = \frac{\dfrac{J_1^*}{p_{r1}^2} - \dfrac{J_2^*}{p_{r2}^2}}{\dfrac{1}{p_{r1}^2} - \dfrac{1}{p_{r2}^2}} \qquad (26)$$

Klins and Clark[14] presented a new method to predict future performance where the bubble point pressure is considered a reference point. From their relations C and n at future time must be computed after the estimation of these parameters at current conditions from Fetkovich's equation. Once these parameters are estimated, the maximum future production rate is calculated by using Fetkovich's equation,

$$q_{o,max,f} = C_f (p_{r,f}^2)^{n_f} \qquad (27)$$

where

$$n_f = n_{p_b} \left(\frac{n}{n_{p_b}}\right)_f \qquad (28)$$

and

$$C_f = C_{p_b} \left(\frac{C}{C_{p_b}}\right)_f \qquad (29)$$

To use this method, one needs a multipoint test in order to be able to compute the value of n and C at the test conditions.

1.5 Summary.

The ability to predict the performance of an oil well has always captured the attention of the petroleum engineer. Many relationships have been proposed to assist the engineer in predicting this performance. In this study, we compare the predictions of the various IPRs for two-phase flow to actual field test data. These comparisons are presented and discussed in the following chapters. Chapter 2 discusses the process for implementing the various relationships while Chapter 3 details the comparison to actual field data. Finally, a summary of this study and its major conclusions are presented in Chapter 4.

CHAPTER 2
INFLOW PERFORMANCE RELATIONSHIPS

The various inflow performance relationships to be evaluated were presented in Chapter 1. This chapter discusses how the relationships are applied by using an example. In addition, a spreadsheet program developed to perform the comparison is described.

2.1 IPR Example Application

This section demonstrates how to apply each IPR by using an example. Table 2.1 contains information that will be used for the prediction of the IPR.

Vogel's Method: In order to use Vogel's equation, one needs to have well test information including reservoir pressure and flowing bottomhole pressure and oil production rate. Using this information and rearranging Eq. 5, one can calculate the maximum flow rate. Using the flow rate of 134 BOPD, the maximum flow rate is

$$q_{o,max} = \frac{134}{1-0.2\left(\frac{1000}{1347}\right)-0.8\left(\frac{1000}{1347}\right)^2} = 326 \text{ BOPD}$$

After $q_{o,max}$ is determined, Eq. *5* can be used to estimate production rates at other values of flowing wellbore pressure to develop an inflow performance curve. For example the flow rate at a 500 psi flowing bottomhole pressure would be

Table 2.1 - Well Test Information Used for Example

p_r = 1347 psi p_b = 2020 psi   S = 2

Test	q_o, BOPD	p_{wf}, psi
1	59	1200
2	97	1100
3	134	1000

$$q_o = 360\left(1 - 0.2\left(\frac{500}{1347}\right) - 0.8\left(\frac{500}{1347}\right)^2\right) = 266 \text{ BPD}$$

Fetkovich's Method: For this method, one should have multirate test data of at least three points in order to calculate the exponent *n* and *C*. If the information is not available, then one can assume that the exponent *n* is unity and perform the calculation. Using the multirate test data in Table 2.1 , one would generate a table similar to the one that follows so that a log-log plot can be made.

q_o, BOPD	p_{wf}, psi	$(p_r^2 - p_{wf}^2)10^3$, psi^2
59	1200	374.4
97	1100	604.4
134	1000	814.4

The data in the above table is plotted on a log-log graph to determine the parameters of Fetkovich's relation *n* and *C*. Fig 2.1 presents this plot. The exponent *n* is the inverse of the slope of this graph and is 1.05 for this example.

After separating and isolating $q_{o,max}$ from Eq. 7 and using the computed *n* value, the maximum flow rate can be obtained.

$$q_{o,max} = \frac{q_o}{\left[1 - \left(\frac{p_{wf}}{p_r}\right)^2\right]^n}$$

$$q_{o,max} = \frac{134}{\left[1 - \left(\frac{1000}{1347}\right)^2\right]^{1.05}} = 312 \text{ BOPD}$$

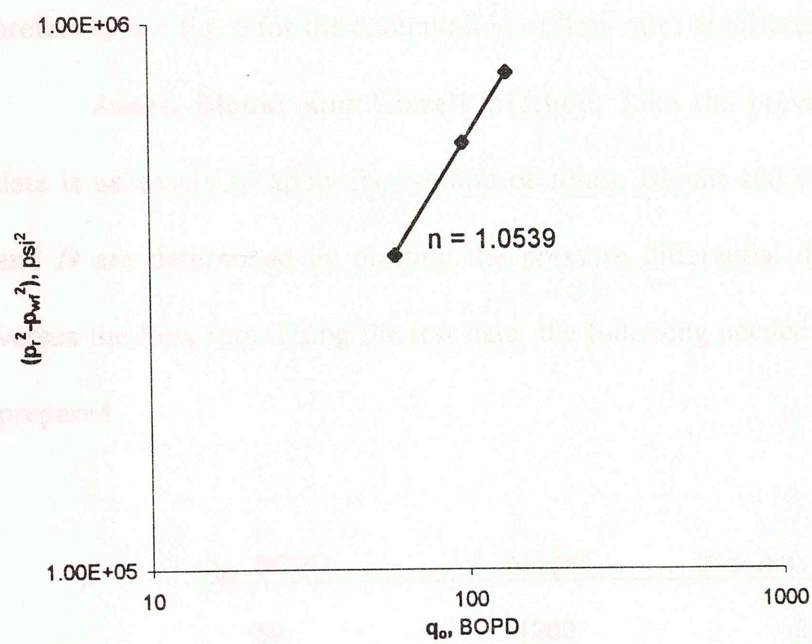

Fig. 2.1 - Fetkovich's plot for the example calculation.

Finally, the estimated production rates at different flowing pressures can be evaluated from Eq. *7* and the construction of the IPR curve completed. For example, at a flowing bottomhole pressure of 500 psi

$$q_o = 292\left[1-\left(\frac{500}{1347}\right)^2\right]^{1.05} = 267 \text{ BOPD}$$

It should be remarked that the value of C was not used in this calculation unless one prefers to use Eq. 6 for the computation of flow rates at different pressures.

Jones, Blount and Glaze's Method: Like the previous method, multipoint data is necessary to apply the method of Jones, Blount and Glaze. The parameters *C* and *D* are determined by plotting the pressure differential divided by the flow rate versus the flow rate. Using the test data, the following needed information and table is prepared.

q_o, BOPD	p_{wf}, psi	$(p_r-p_{wf})/q_o$, psi/BOPD
59	1200	2.49
97	1100	2.55
134	1000	2.59

Fig. 2.2 is a plot of these values on cartesian paper which allows the determination of the intercept, C, and the slope, D. These parameters are 2.41 psi/BOPD and 0.0013 psi/BOPD^2, respectively.

Using these values and solving Eq. 9 for the maximum flow rate by letting the flowing bottomhole pressure equal zero yields

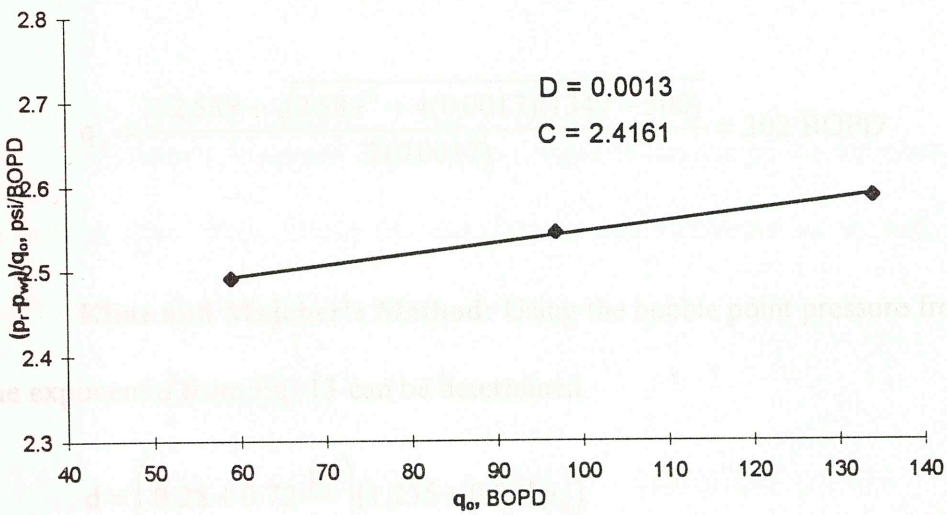

Fig. 2.2 - Jones, Blount and Glaze plot for the example calculation.

$$q_{o,max} = \frac{-C+\sqrt{C^2+4D(p_r-p_{wf})}}{2D}$$

$$q_{o,max} = \frac{-2.41+\sqrt{2.41^2+4(0.0013)(1347-0)}}{2(0.0013)} = 449 \text{ BOPD}$$

Flow rates at other values of flowing pressure can be determined by using the above relation. At a flowing bottomhole pressure of 500 psi, the flow rate is estimated as

$$q_o = \frac{-2.589+\sqrt{2.589^2+4(0.0017)(1347-500)}}{2(0.0017)} = 302 \text{ BOPD}$$

Klins and Majcher's Method: Using the bubble point pressure from Table 2.1 the exponent *d* from Eq. 13 can be determined.

$$d = \left(0.28+0.72\frac{p_r}{p_b}\right)(1.235+0.001p_b)$$

$$d = \left(0.28+0.72\frac{1347}{2020}\right)(1.235+0.001(2020)) = 2.478$$

By rearranging Eq. 12, the maximum flow rate can be obtained

$$q_{o,max} = \frac{q_o}{\left\{1-0.295\left(\frac{p_{wf}}{p_r}\right)-0.705\left(\frac{p_{wf}}{p_r}\right)^d\right\}}$$

$$q_{o,max} = \frac{134}{\left\{1 - 0.295\left(\frac{1000}{1347}\right) - 0.705\left(\frac{1000}{1347}\right)^{2.478}\right\}} = 302 \text{ BOPD}$$

From this estimate of the maximum flow rate, the IPR will be plotted by calculating flow rates at desired flowing pressures from Eq. 12. If one takes a pressure value of 500 psi, then the resulting flow rate would be

$$q_{o,max} = 333\left\{1.0 - 0.295\left(\frac{500}{1347}\right) - 0.705\left(\frac{500}{1347}\right)^{2.478}\right\} = 251 \text{ BOPD}$$

Sukarno's Method: This method requires the use of the estimated skin factor to predict flow rates. Using the skin factor, one calculates a_1, a_2 and a_3 using the coefficients in Table 1.1. This yields

$$a_n = b_0 + b_1 S + b_2 S^2 + b_3 S^3$$

$$a_o = 1.03940 + 0.12657(2) + 0.0135(2)^2 - 0.00062(2)^3 = 1.342$$

$$a_1 = 0.01668 - 0.00385(2) + 0.00217(2)^2 - 0.0001(2)^3 = 0.017$$

$$a_2 = -0.0858 + 0.00201(2) - 0.00456(2)^2 + 0.0002(2)^3 = -0.098$$

$$a_3 = 0.00952 - 0.00391(2) + 0.0019(2)^2 - 0.00001(2)^3 = 0.009$$

Next the FE value is calculated from Eq. 15 to yield

$$FE = \left\{ a_o + a_1\left(\frac{p_{wf}}{p_r}\right) + a_2\left(\frac{p_{wf}}{p_r}\right)^2 + a_3\left(\frac{p_{wf}}{p_r}\right)^3 \right\}$$

$$FE = \left\{ 1.342 + 0.017\left(\frac{1000}{1347}\right) - 0.098\left(\frac{1000}{1347}\right)^2 + 0.009\left(\frac{1000}{1347}\right)^3 \right\} = 1.3$$

The maximum flow rate is then determined by using Eq. 14

$$q_{o,max@S=0} = \frac{q_o}{FE\left\{ 1 - 0.1489\left(\frac{p_{wf}}{p_r}\right) - 0.4418\left(\frac{p_{wf}}{p_r}\right)^2 - 0.4093\left(\frac{p_{wf}}{p_r}\right)^3 \right\}}$$

$$q_{o,max@S=0} = \frac{134}{1.3\left\{ 1 - 0.1489\left(\frac{1000}{1347}\right) - 0.4418\left(\frac{1000}{1347}\right)^2 - 0.4093\left(\frac{1000}{1347}\right)^3 \right\}} = 215 \text{ BOPD}$$

The flow rate at a given value of flowing bottomhole pressure is obtained by computing a new FE value and then using Eq. 14. From this calculation at different flowing pressures, an IPR curve can be constructed. At a value of 500 psi,

$$FE = \left\{ 1.342 + 0.017\left(\frac{500}{1347}\right) - 0.098\left(\frac{500}{1347}\right)^2 + 0.009\left(\frac{500}{1347}\right)^3 \right\} = 1.34$$

$$q_{o,actual} = 215 \times 1.34\left\{ 1 - 0.1489\left(\frac{500}{1347}\right) - 0.4418\left(\frac{500}{1347}\right)^2 - 0.4093\left(\frac{500}{1347}\right)^3 \right\} = 248 \text{ BOPD}$$

These example calculations are summarized in Table 2.2. As indicated, the calculated values vary among the methods.

2.2 Methodology

To analyze the data used in this study, a spreadsheet program was created to perform the rate-pressure calculations for each IPR method. Fig. 2.3 is an illustration of the calculation sheet of this program. Input parameters include the test data point (rates and pressures), average reservoir pressure, and bubble point pressure. Additional information required for each method are included in the parameters section. These include the exponents for the multirate methods and the skin factor for Sukarno's method. In the lower half, actual multipoint test data are imported for comparison purposes. Finally, a column was allocated for each method to estimate the flow rate at a given pressure. These values are calculated from the test data for the actual flowing bottomhole pressure. This allows a direct comparison between the actual flow rate and the calculated one.

This program was used to analyze the field data collected for this study. The petroleum literature was searched for suitable multirate tests. In total 26 multirate tests were collected from 12 fields for analysis. Four fields are from Oklahoma while eight are foreign fields. Test data range from the 1930's to the 1990's and cover a variety of reservoir conditions.

Fields and data were chosen in such a way that problems due to transient effects were avoided. Generally the tests consisted of flow-after-flow or isochronal tests of a few hours duration. The testing sequence varied from well to well. A total number of 125 test points have been analyzed. The pressure drawdown in these wells ranged from 2% to 90% with the majority being below 60%, based on the reservoir pressure. The

Table 2.2 - Summary of the Calculated Flow Rates for the Example

	Vogel	Fetkovitch	Jones	Klins	Sukarno
$q_{o,max}$ BOPD	326	312	449	302	288
$q_{o@500psi}$ BOPD	266	267	302	251	248

				n	C & D	d	S & FE
			1	1.054	2.42 0.0013	2.48	2 1.30
				$q_{o,max}$			
		326.3	298.5	311.7	449.0	301.8	214.8
Field Data		Vogel	Fetkovitch	Fetkovitch	Jones	Klins	Sukarno
q_o, BOPD	p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
0	1347	0	0	0	0	0	0
59	1200	61.0	61.6	59.1	59.0	62.7	62.8
97	1100	98.9	99.4	97.9	97.2	100.3	100.4
134	1000	134.0	134.0	134.0	134.0	134.0	134.0
-	900	166.2	165.3	167.1	169.5	164.0	163.8
-	800	195.5	193.2	197.1	204.0	190.4	189.8
-	700	221.9	217.9	223.7	237.4	213.5	212.3
-	600	245.5	239.3	246.9	270.0	233.5	231.4
-	500	266.1	257.4	266.6	301.6	250.5	247.4
-	400	283.9	272.2	282.8	332.5	264.9	260.5
-	300	298.9	283.7	295.4	362.6	276.8	270.8
-	200	310.9	292.0	304.5	392.0	286.7	278.7
-	100	320.1	296.9	309.9	420.8	294.9	284.4
-	0	326.3	298.5	311.7	449.0	301.8	288.2

Fig. 2.3 - Calculation sheet from the program.

calculated pressure-rate information was then compared to the field data both in a graphical and tabular format. This provided a means to make a qualitative comparison of the various IPR methods. In addition, percent differences were calculated for each data point and averaged on a well-by-well basis for quantitative comparisons.

CHAPTER 3

IPR COMPARISONS

In this chapter, the IPR methods are compared using field data. Well test data for 26 cases were collected from the petroleum engineering literature. Each data set was analyzed with nine cases presented in this chapter. The remainder analyses are presented in Appendix A. Table 3.1 identifies the cases used in this study by a well identifier and the source of the data.

3.1. Case 1

In 1931, Millikan and Sidewell[15] presented multirate test data for a well producing from the Hunton Lime in the Carry City Field of Oklahoma. The test was made over a period of about two weeks and rate data taken in a random manner rather than in an increasing or decreasing order. The average reservoir pressure was 1600 psi with an estimated bubble point pressure of 2530 psi. A skin value of zero was assumed. The field data are presented in Table 3.2.

Table 3.3 was created using the test information at a flowing bottomhole pressure of 1267 psi, representing a 21% pressure drawdown. As can be seen, the absolute open flow potential (AOF) varies from 2652 to 3706 BOPD. The largest flow rate was calculated with Vogel's IPR while the smallest rate was obtained using Fetkovich's method.

Fig. 3.1 presents the IPR curves for the methods used. Visual inspection of the graph indicates that the methods of Fetkovich and Jones, Blount and Glaze do a very

Table 3.1 - Identification of Wells Analyzed

Test Case	Actual Well Identification	Reference
1	Carry City Field, OK	1
2	Well A, Keokuk Field, OK December 1934	16
3	Well A, Keokuk Field, OK August 1935	16
4	Well B, Keokuk Field, OK December 1934	16
5	Well B, Keokuk Field, OK August 1935	16
6	Well C, Lucien Field, OK	16
7	Well D, Lucien Field, OK	16
8	Well E, Lucien Field, OK	16
9	Well F, South Burbank Field, OK	16
10	Well G, South Burbank Field, OK	16
11	Well H, South Burbank Field, OK	16
12	Well 6, Field A	6
13	Well 3, Field A	6
14	Well 3-c, Field C	6
15	Well 14, Field A	6
16	Well 5, Field D	6
17	Well 6, Field D	6
18	Well 1, Field E	6
19	Well TMT-27, Miring Timur Field, Indonesia	17
20	Well 1, Field F	6
21	Well 2, Field F	6
22	Well A	18
23	Well 8, West Texas Area	19
24	Well 2-b, Field C	6
25	Well 4, Field C	6
26	Well 4, Field D	6

Table 3.2 - Well Test Information for the Carry City Well[15]

p_r = 1600 psi p_b = 2530 psi (estimated)

S = 0 (assumed)

Test Data

p_{wf}	q_o, BOPD
1600	0
1558	235
1497	565
1476	610
1470	720
1342	1045
1267	1260
1194	1470
1066	1625
996	1765
867	1895
787	1965
534	2260
351	2353
183	2435
166	2450
0	-

Table 3.3 - Estimated Flow Rates for the Carry City Well at a 21% Pressure Drawdown

Test Information :

q_o = 1260 BOPD p_{wf} = 1267 psi p_r = 1600 psi p_b = 2530 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1194	1470	1502	1497	1426	1260	1480	1489
1066	1625	1896	1879	1680	1468	1823	1852
996	1765	2096	2069	1800	1571	1989	2029
867	1895	2434	2387	1995	1747	2256	2320
787	1965	2624	2561	2099	1848	2399	2477
534	2260	3129	3002	2353	2140	2753	2867
351	2353	3401	3216	2472	2330	2933	3058
183	2435	3583	3334	2538	2492	3060	3174
166	2450	3597	3342	2542	2508	3071	3183
0	-	3706	3379	2562	2658	3172	3248

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
1194	1470	2%	2%	-3%	-14%	1%	1%
1066	1625	17%	16%	3%	-10%	12%	14%
996	1765	19%	17%	2%	-11%	13%	15%
867	1895	28%	26%	5%	-8%	19%	22%
787	1965	34%	30%	7%	-6%	22%	26%
534	2260	38%	33%	4%	-5%	22%	27%
351	2353	45%	37%	5%	-1%	25%	30%
183	2435	47%	37%	4%	2%	26%	30%
166	2450	47%	36%	4%	2%	25%	30%
Average Difference :		31%	26%	4%	7%	18%	22%

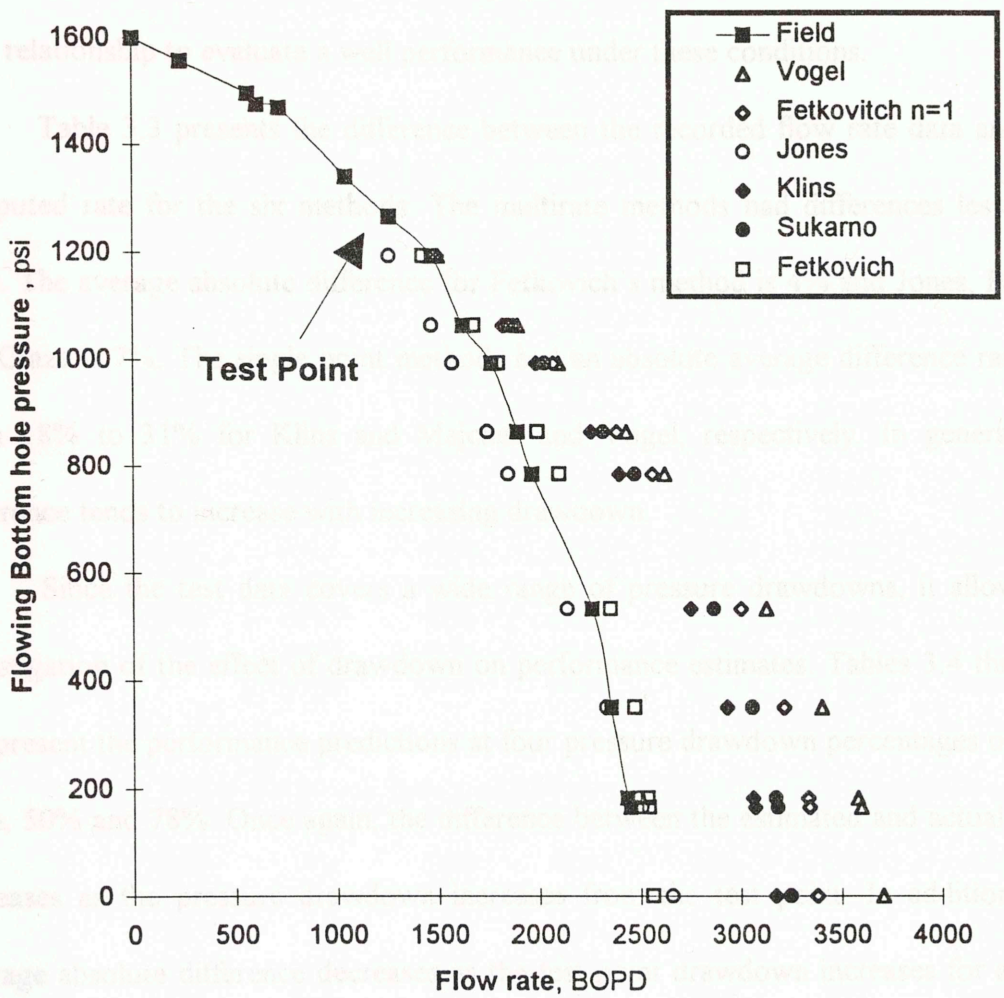

Fig. 3.1 - Performance curves for the Carry City Well.

good job of estimating the actual well performance. The other methods capture the general shape of the data but overestimate the performance. If a straight-line assumption was used in this case, a maximum flow rate of 6054 BOPD would have been calculated from the test point. This estimate is over 60% greater than the highest predicted rate by the IPR methods. This shows the importance of using a multiphase flow relationship to evaluate a well performance under these conditions.

Table 3.3 presents the difference between the recorded flow rate data and the computed rate for the six methods. The multirate methods had differences less than 10%. The average absolute difference for Fetkovich's method is 4% and Jones, Blount and Glaze is 7%. The single point methods had an absolute average difference ranging from 18% to 31% for Klins and Majcher and Vogel, respectively. In general the difference tends to increase with increasing drawdown.

Since the test data covers a wide range of pressure drawdowns, it allows an investigation of the effect of drawdown on performance estimates. Tables 3.4 through 3.7 present the performance predictions at four pressure drawdown percentages of 9%, 38%, 50% and 78%. Once again, the difference between the estimated and actual rates increases as the pressure drawdown increases from the test point. In addition, the average absolute difference decreases as the test point drawdown increases for all the methods except for Jones, Blount and Glaze where there is a slight increase at the test pressure.

For example, if one takes Vogel's method, the AOF diminishes from 5108 BOPD at 9% drawdown to 2564 BOPD at 78%. This is almost a 100% reduction in the estimate. The average difference decreases from 72% at a flowing pressure of 1470

Table 3.4 - Estimated Flow Rates for the Carry City Well at a 9% Pressure Drawdown

Test Information :

q_o = 720 BOPD p_{wf} = 1470 psi p_r = 1600 psi p_b = 2530 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1342	1045	1376	1369	1343	1276	1341	1357
1267	1260	1736	1722	1677	1597	1667	1697
1194	1470	2070	2046	1982	1893	1958	2006
1066	1625	2613	2568	2471	2381	2412	2494
996	1765	2888	2829	2713	2634	2631	2733
867	1895	3354	3262	3115	3078	2984	3125
787	1965	3616	3501	3336	3340	3174	3336
534	2260	4311	4104	3892	4117	3642	3862
351	2353	4687	4396	4160	4637	3881	4118
183	2435	4937	4558	4309	5090	4048	4275
166	2450	4958	4569	4318	5134	4063	4288
0	-	5108	4618	4364	5560	4196	4375

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
1342	1045	32%	31%	28%	22%	28%	30%
1267	1260	38%	37%	33%	27%	32%	35%
1194	1470	41%	39%	35%	29%	33%	36%
1066	1625	61%	58%	52%	47%	48%	53%
996	1765	64%	60%	54%	49%	49%	55%
867	1895	77%	72%	64%	62%	57%	65%
787	1965	84%	78%	70%	70%	62%	70%
534	2260	91%	82%	72%	82%	61%	71%
351	2353	99%	87%	77%	97%	65%	75%
183	2435	103%	87%	77%	109%	66%	76%
166	2450	102%	86%	76%	110%	66%	75%
Average Difference		72%	65%	58%	64%	52%	58%

Table 3.5 - Estimated Flow Rates for the Carry City Well at a 38% Pressure Drawdown

Test Information :

q_o = 1765 BOPD p_{wf} = 996 psi p_r = 1600 psi p_b = 2530 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
867	1895	2050	2036	1955	2343	2002	2018
787	1965	2210	2184	2056	2485	2129	2155
534	2260	2635	2561	2303	2896	2443	2494
351	2353	2864	2743	2419	3163	2604	2660
183	2435	3017	2844	2483	3392	2716	2761
166	2450	3030	2851	2487	3414	2726	2769
0	-	3121	2882	2506	3626	2815	2825

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
867	1895	8%	7%	3%	24%	6%	6%
787	1965	12%	11%	5%	26%	8%	10%
534	2260	17%	13%	2%	28%	8%	10%
351	2353	22%	17%	3%	34%	11%	13%
183	2435	24%	17%	2%	39%	12%	13%
166	2450	24%	16%	2%	39%	11%	13%
Average Difference :		18%	14%	3%	32%	9%	11%

Table 3.6 - Estimated Flow Rates for the Carry City Well at a 50 % Pressure Drawdown

Test Information :

q_o = 1965 BOPD p_{wf} = 787 psi p_r = 1600 psi p_b = 2530 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
534	2260	2343	2303	2195	2187	2255	2274
351	2353	2547	2467	2303	2377	2403	2425
183	2435	2683	2558	2362	2539	2506	2518
166	2450	2694	2564	2366	2555	2515	2525
0	-	2775	2592	2384	2706	2598	2576

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
534	2260	4%	2%	-3%	-3%	0%	1%
351	2353	8%	5%	-2%	1%	2%	3%
183	2435	10%	5%	-3%	4%	3%	3%
166	2450	10%	5%	-3%	4%	3%	3%
		32%	17%	11%	13%	8%	10%
Average Difference :		8.0%	4.1%	2.8%	3.2%	2.0%	2.5%

Table 3.7 - Estimated Flow Rates for the Carry City Field at a 78% Pressure Drawdown

Test Information :

q_o = 2353 BOPD p_{wf} = 351 psi p_r = 1600 psi p_b = 2530 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
183	2435	2479	2440	2413	2628	2454	2443
166	2450	2489	2445	2417	2644	2463	2450
0	-	2564	2472	2435	2795	2544	2499

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
183	2435	1.8%	0.2%	-0.9%	7.9%	0.8%	0.3%
166	2450	1.6%	-0.2%	-1.4%	7.9%	0.5%	0.0%
		3.4%	0.4%	2.3%	15.9%	1.3%	0.3%
Average Difference :		1.7%	0.2%	1.1%	7.9%	0.7%	0.2%

psi to almost 1.7% with a test pressure of 351 psi. The other single point methods are comparable to Vogel's with less severity.

On the contrary for this case, except for the lowest pressure drawdown, Fetkovich's method is invariable throughout the analysis with an average difference varying from 4% to 1.1%. For this particular case, a 19% pressure drawdown was sufficient to predict the performance of the well using Fetkovich's method. With Jones, Blount and Glaze, the results were not the same due to the change of the constants C and D which govern the method. This had the consequence of varying the average difference and AOF. The best or the smallest average absolute difference was obtained at a 50% drawdown rather than at the largest one of 78%. This can be illustrated by the fact that the data points did not lie on a perfect line as shown in Fig. 3.2. The test point used affects the values of C and D and the estimated performance.

In summary, Fetkovich's relation provided the best estimates of well performance over the entire range of interest. In general, the difference in performance predictions increased as the pressure drawdown increased from the test pressure. Also, the average difference in the predictions decreased as the test pressure drawdown increased.

3.2 Cases 2 and 3

The second well[16] presented is from the Keokuk Pool in Seminole County, Oklahoma. Two sets of data were obtained, the first was run in December 1934 and the second in August 1935. These data were selected to evaluate the effect of depletion on the IPR methods. During this period, the reservoir pressure dropped from 1734 psi to

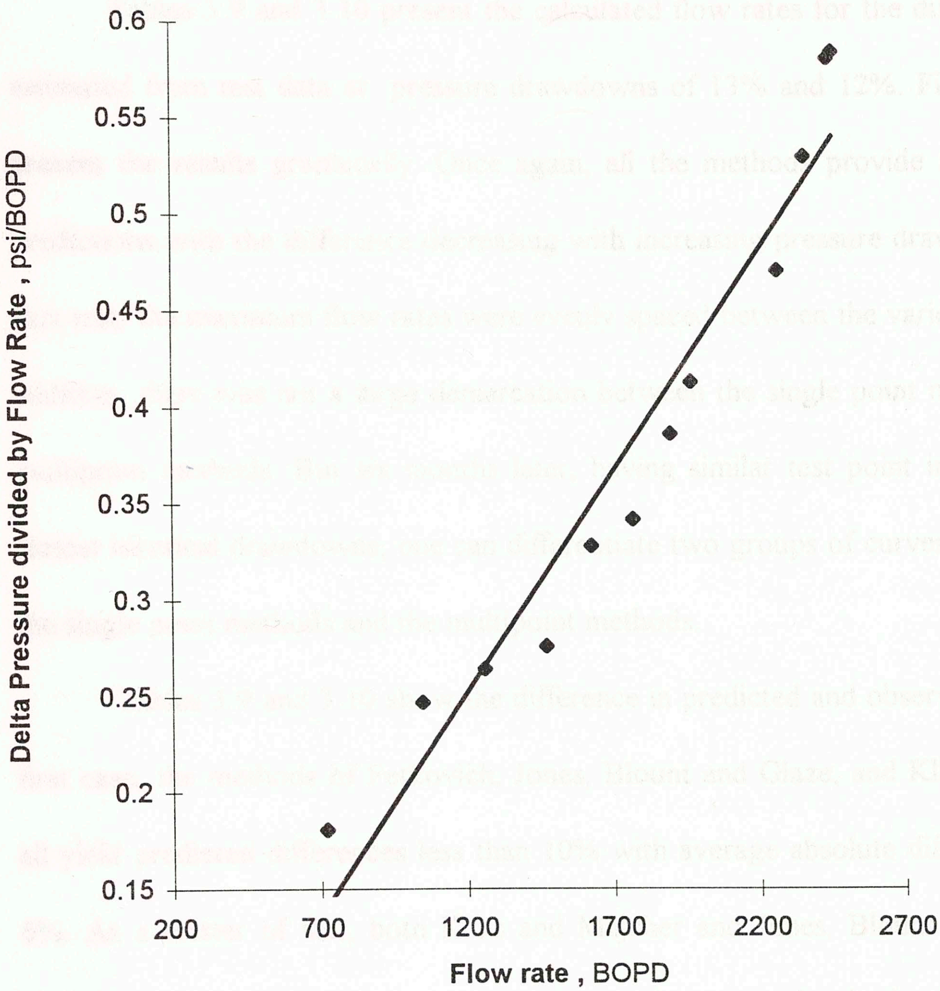

Fig. 3.2 - Jones, Blount and Glaze plot with all the test data for the Carry City Well.

1609 psi. For this analysis, the bubble point pressure was estimated at 3420 psi. The test data are shown in Table 3.8. The test data only covers approximately 40% of the pressure range.

Tables 3.9 and 3.10 present the calculated flow rates for the different methods estimated from test data at pressure drawdowns of 13% and 12%. Figs. 3.3 and 3.4 present the results graphically. Once again, all the methods provide a range of rate predictions with the difference decreasing with increasing pressure drawdown. For the first test, the maximum flow rates were evenly spaced between the various methods. In addition, there was not a large demarcation between the single point methods and the multipoint methods. But six months later, having similar test point information with almost identical drawdowns, one can differentiate two groups of curves represented by the single point methods and the multipoint methods.

Tables 3.9 and 3.10 show the difference in predicted and observed rates. In the first case, the methods of Fetkovich, Jones, Blount and Glaze, and Klins and Majcher all yield predicted differences less than 10% with average absolute differences around 6%. As a matter of fact, both Klins and Majcher and Jones, Blount and Glaze give almost the same AOF. However, at the second pressure level, the difference in the predictions of Klins and Majcher increase above 10%.

It is also interesting to note that there is little change in the estimate of the AOF for the single point methods in this case while the multipoint methods yielded approximately a 20% reduction in the predicted maximum rate. This effect results from the utilization of more than one data point in the multipoint methods which should improve their reliability. Table 3.11 presents the change in AOF after six month for

Table 3.8 - Well Test Information for Well A, Keokuk Field, OK, at Two Different Pressures[16]

December, 1934	August, 1935
p_r = 1734 psi	p_r = 1609 psi
p_b = 3420 psi (estimated)	p_b = 3420 psi (estimated)
S = 0 (assumed)	S = 0 (assumed)

Test Data

p_{wf}	q_o, BOPD	p_{wf}	q_o, BOPD
1734	0	1609	0
1653	252	1576	160
1507	516	1535	253
1335	768	1420	462
1190	982	1256	702
1079	1125		

Table 3.9 - Estimated Flow Rates for Well A, Keokuk Field, December 1934

Test Information :

q_o = 516 BOPD p_{wf} = 1507 psi p_r = 1734 psi p_b = 3420 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1335	768	865	859	753	752	829	849
1190	982	1130	1116	915	914	1046	1092
1079	1125	1315	1292	1020	1024	1187	1256
1000	-	1438	1407	1087	1097	1275	1361
900	-	1583	1541	1162	1185	1374	1481
800	-	1715	1660	1229	1267	1459	1586
700	-	1834	1765	1286	1346	1532	1679
600	-	1941	1856	1335	1421	1594	1758
500	-	2036	1933	1376	1492	1648	1826
400	-	2119	1997	1409	1561	1694	1882
300	-	2189	2046	1435	1628	1735	1927
200	-	2247	2081	1453	1692	1770	1963
100	-	2292	2102	1464	1754	1803	1990
0		2325	2109	1467	1814	1835	2009

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
1335	768	13%	12%	-2%	-2%	8%	11%
1190	982	15%	14%	-7%	-7%	7%	11%
1079	1125	17%	15%	-9%	-9%	6%	12%
Average Difference		15%	13%	6%	6%	7%	11%

Table 3.10 - Estimated Flow Rates for Well A, Keokuk Field, August 1935

Test Information :

q_o =462 BOPD p_{wf} = 1420 psi p_r = 1609 psi p_b = 3420 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1256	702	822	816	660	634	791	806
1200	-	936	927	715	688	889	912
1100	-	1128	1113	801	776	1049	1087
1000	-	1306	1282	876	856	1188	1244
900	-	1470	1436	940	929	1310	1383
800	-	1620	1573	995	998	1415	1506
700	-	1756	1694	1043	1062	1505	1613
600	-	1877	1799	1083	1123	1582	1704
500	-	1984	1888	1116	1181	1647	1781
400	-	2077	1960	1143	1236	1703	1845
300	-	2155	2017	1163	1290	1751	1897
200	-	2220	2057	1178	1341	1792	1937
100	-	2270	2081	1186	1390	1829	1967
0	-	2305	2089	1189	1438	1863	1987

pwf, psi	qo, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
1256	702	17%	16%	-6%	-10%	13%	15%

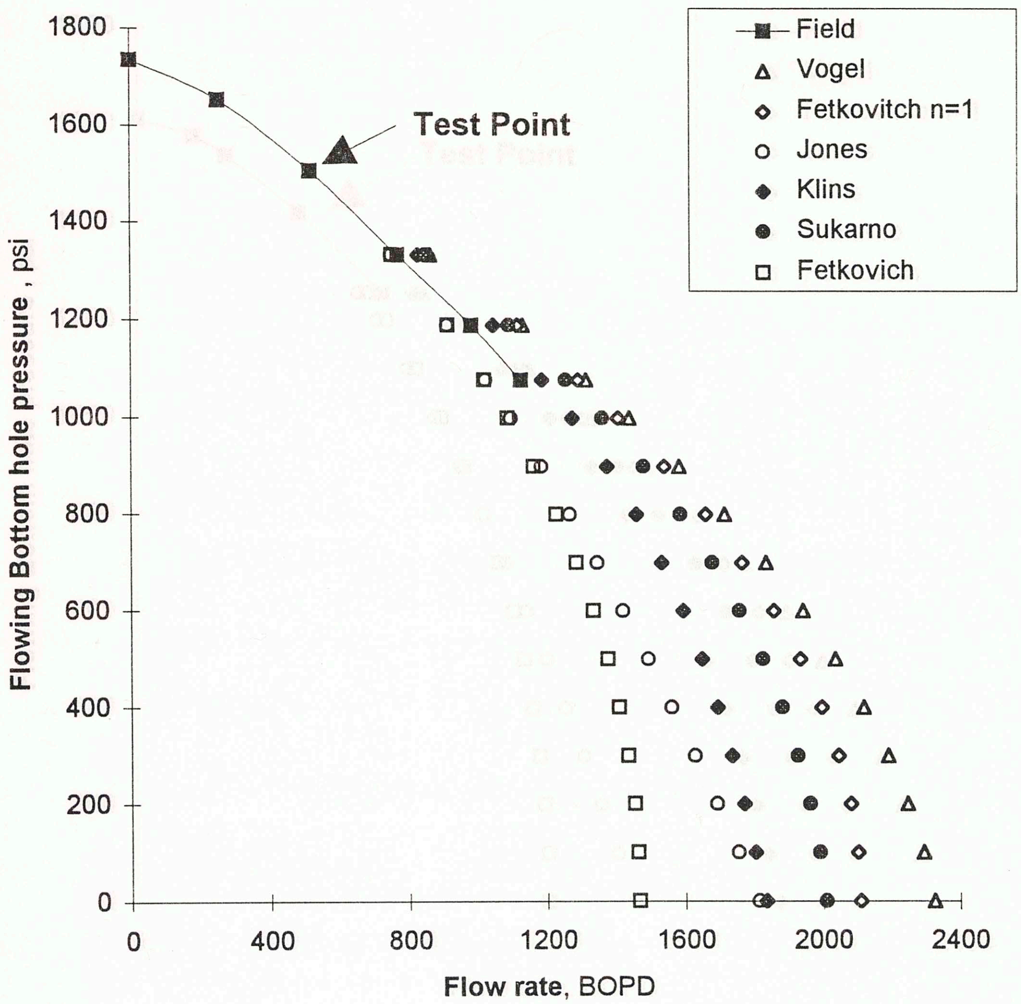

Fig. 3.3 - Performance curves for Well A, Keokuk Field, December 1934.

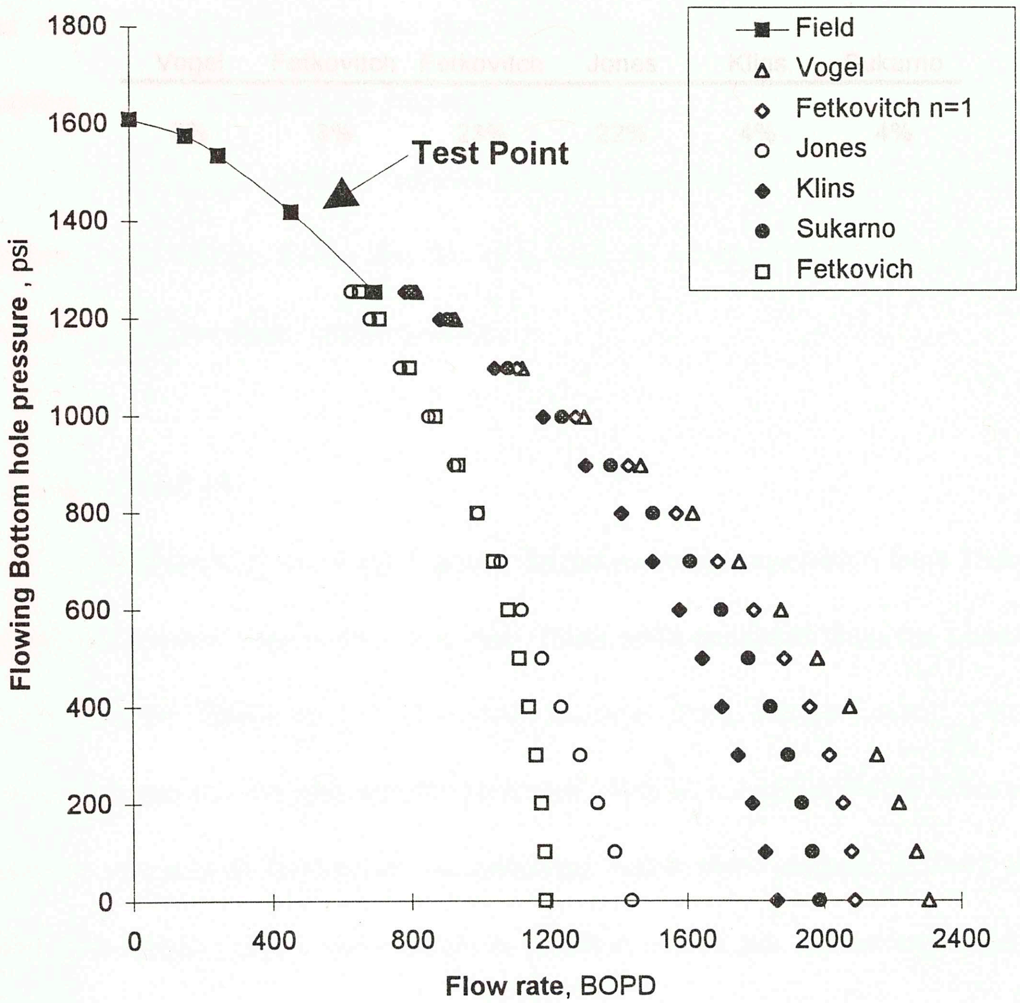

Fig. 3.4 - Performance curves for Well A, Keokuk Field, August 1935.

Table 3.11 - Change in AOF for Well A, Keokuk Field after Six Months

Vogel	Fetkovitch	Fetkovitch	Jones	Klins	Sukarno
3%	3%	23%	22%	4%	4%

each method. The change in the multipoint methods is due to the changes in the *n*, *C*, and *D* values presented in Figs. 3.5 and 3.6. This observation is important when one wants to forecast future performance since the flow coefficients change with depletion and may affect future estimates. One also notes the AOF predicted by Klins and Majcher increased between the two test periods.

This example tends to indicate that the reliability of the various performance methods may change during the life of a well. In addition, the multipoint methods appear to yield the most reliable predictions.

3.3 Cases 7 and 10

In this section, two wells[16] where the deliverability exponent *n* from Fetkovich's equation is greater than one are analyzed. These wells produced from the Lucien Pool, Noble County, Oklahoma and the South Burbank Pool, Osage County, Oklahoma. Table 3.12 presents the test data for each well. Well D, located in Noble County, had a reservoir pressure of 1800 psi and an estimated bubble point pressure of 3640 psi while Well G in Osage County had a reservoir pressure of 866 psi and an estimated bubble point pressure of 2985 psi. For both wells, a skin factor of zero was assumed. The minimum and maximum drawdown for the first Well D was 6.5% and 38%, respectively. The maximum pressure drawdown for Well G was greater than 50%.

Figs. 3.7 and 3.8 show the predicted performance for each well. It appears Fetkovich's method is most reliable in estimating the data. In this case, Fetkovich's method provided the highest estimate of AOF compared to the other methods and also

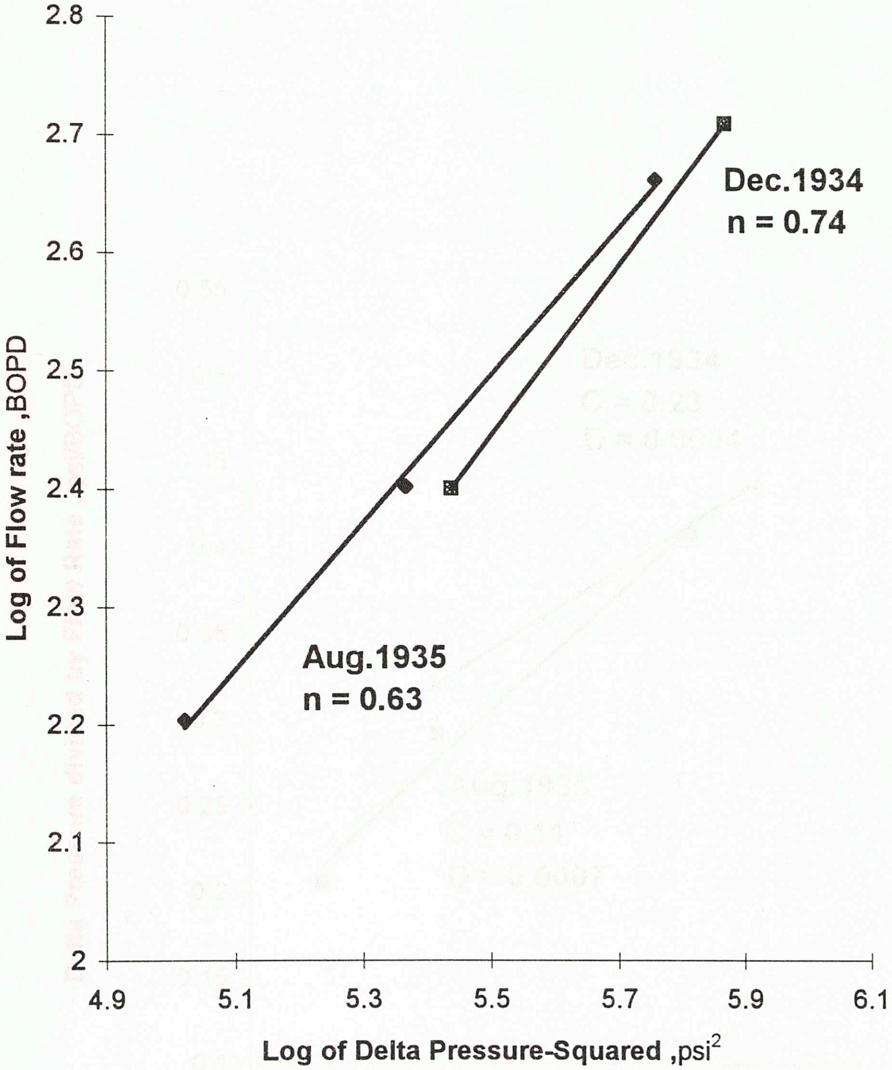

Fig. 3.5. Change in the *n* value for Well A, Keokuk Field.

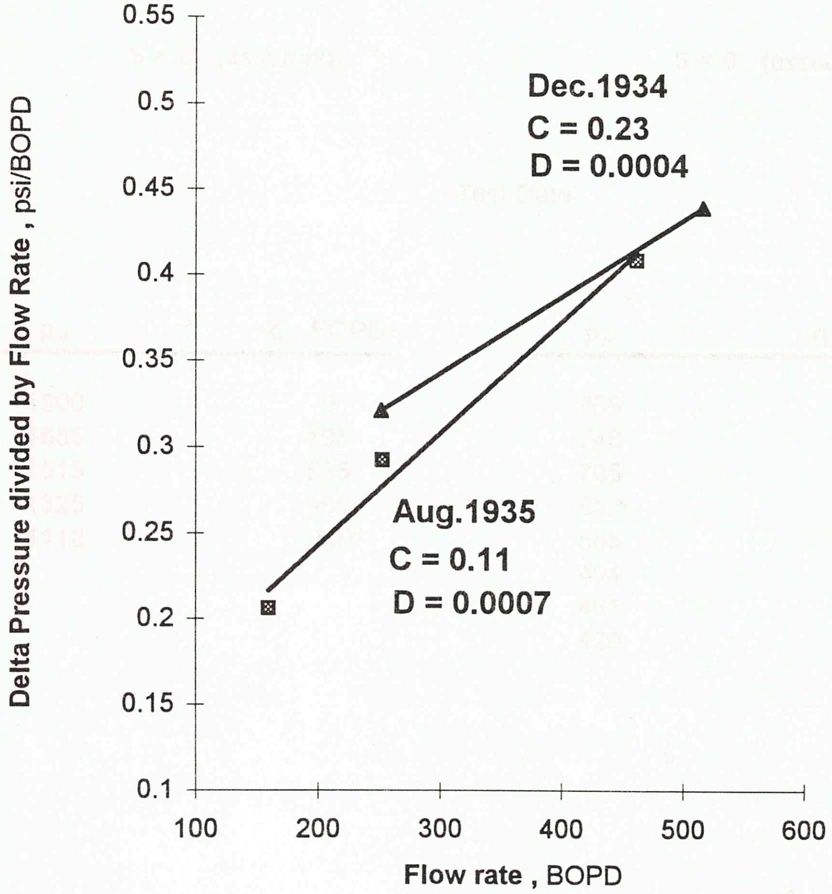

Fig. 3.6 - Change in the values of *C* and *D* for well A, Keokuk Field.

Table 3.12 - Well Test Information for Wells D and G in Noble and Osage Counties, OK[16]

Well D	Well G
p_r = 1800 psi	p_r = 866 psi
p_b = 3760 psi (estimated)	p_b = 3040 psi (estim
S = 0 (assumed)	S = 0 (assumed)

Test Data

p_{wf}	q_o, BOPD	p_{wf}	q_o, BOPD
1800	0	866	0
1685	195	748	107
1515	535	705	160
1325	960	652	196
1110	1507	566	288
		494	407
		461	450
		420	539

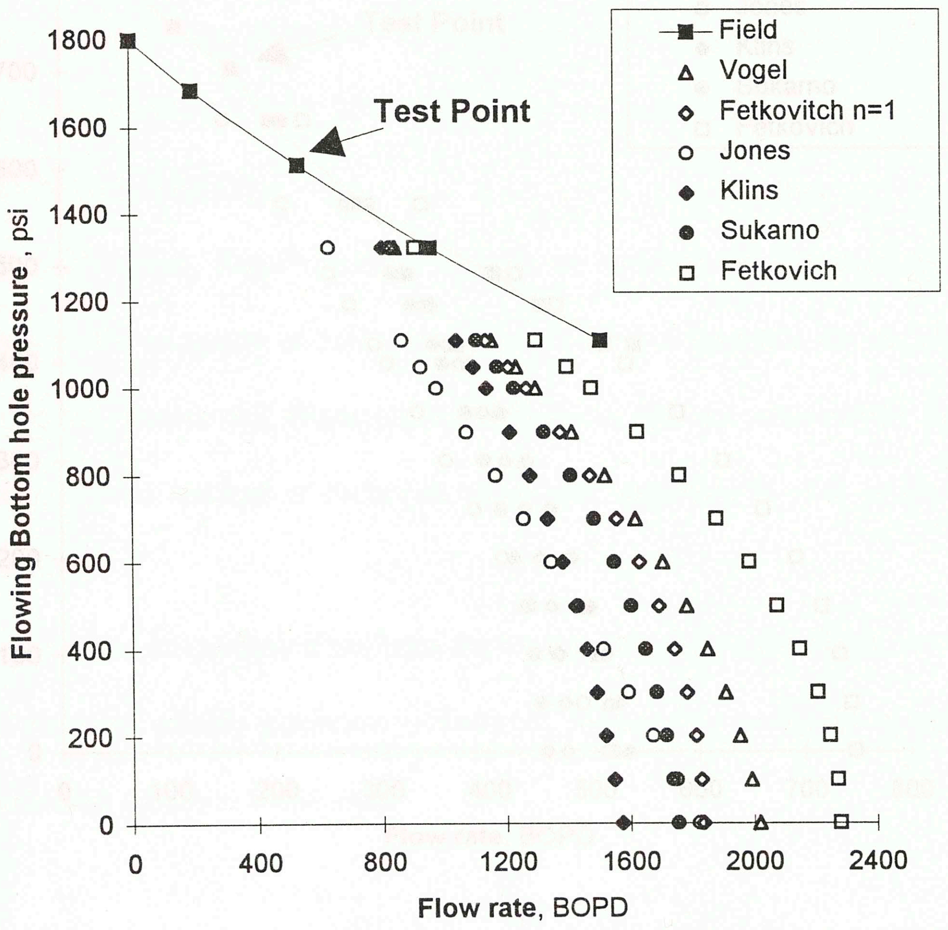

Fig. 3.7 - Performance curves for Well D, Lucien Pool, Noble County, OK.

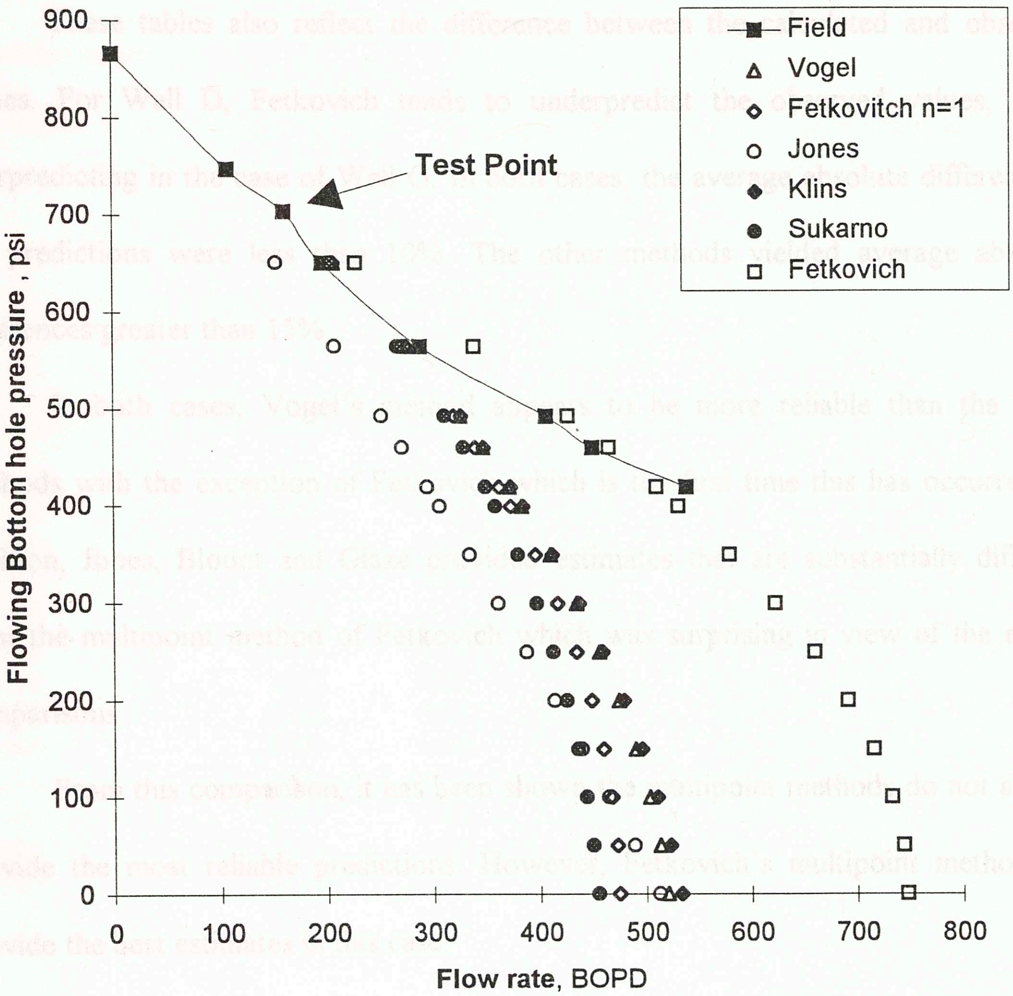

Fig. 3.8 - Performance curves for Well G, South Burbank Pool, Osage County, OK.

estimated the high flow rates better. For Well G, the method predicts a substantially higher AOF of 747 BOPD versus 421 to 534 BOPD for the other methods. Tables 3.13 and 3.14 present the calculated values.

These tables also reflect the difference between the calculated and observed values. For Well D, Fetkovich tends to underpredict the observed values, while overpredicting in the case of Well G. In both cases, the average absolute difference in the predictions were less than 10%. The other methods yielded average absolute differences greater than 15%.

In both cases, Vogel's method appears to be more reliable than the other methods with the exception of Fetkovich which is the first time this has occurred. In addition, Jones, Blount and Glaze provided estimates that are substantially different from the multipoint method of Fetkovich which was surprising in view of the earlier comparisons.

From this comparison, it has been shown the multipoint methods do not always provide the most reliable predictions. However, Fetkovich's multipoint method did provide the best estimates in this case.

3.4 Cases 13 and 15

Fetkovich[6] presented flow-after-flow data for 14 wells producing from solution-gas drive carbonate reservoirs in Field A. Table 3.15 provides reservoir properties while Table 3.16 presents test data for Wells 3 and 14. The main purpose for this example is to demonstrate that the various methods may produce different results for wells producing from similar reservoirs and geological environments.

Table 3.13 - Estimated Flow Rates for Well D, Lucien Pool, Osage County, OK

Test Information :

q_o = 535 BOPD $\quad$ p_{wf} = 1515 psi $\quad$ p_r = 1800 psi $\quad$ p_b = 3760 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1325	960	847	841	910	700	805	830
1110	1507	1156	1137	1299	977	1042	1108
1050	-	1234	1210	1398	1051	1096	1175
1000	-	1296	1268	1478	1112	1138	1228
900	-	1414	1376	1626	1231	1213	1324
800	-	1521	1472	1761	1346	1278	1409
700	-	1618	1557	1881	1459	1334	1484
600	-	1705	1631	1986	1569	1382	1548
500	-	1782	1693	2076	1676	1423	1603
400	-	1850	1744	2150	1781	1459	1649
300	-	1907	1784	2207	1883	1491	1686
200	-	1954	1812	2249	1984	1520	1715
100	-	1992	1829	2273	2082	1547	1738
0	-	2019	1835	2282	2179	1573	1753

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
1325	960	-12%	-12%	-5%	-27%	-16%	-14%
1110	1507	-23%	-25%	-14%	-35%	-31%	-26%
Average difference		18%	18%	9%	31%	24%	20%

Table 3.14 - Estimated Flow Rates for Well G, South Burbank Pool, Noble County, OK

Test Information :

q_o = 160 BOPD p_{wf} =705 psi p_r = 866 psi p_b = 3040 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
652	196	206	205	228	153	206	204
566	288	275	272	339	208	275	267
494	407	326	320	428	252	326	311
461	450	348	340	466	271	348	329
420	539	373	363	511	295	373	350
400	-	384	373	532	306	385	359
350	-	411	397	580	334	413	380
300	-	435	417	623	361	437	398
250	-	456	435	661	388	460	413
200	-	475	449	691	414	479	426
150	-	491	460	716	440	496	436
100	-	504	468	733	465	511	444
50	-	514	473	744	489	523	451
0	-	521	474	747	513	534	455

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
652	196	5%	5%	16%	-22%	5%	4%
566	288	-5%	-6%	18%	-28%	-4%	-7%
494	407	-20%	-21%	5%	-38%	-20%	-24%
461	450	-23%	-24%	4%	-40%	-23%	-27%
420	539	-31%	-33%	-5%	-45%	-31%	-35%
Average Difference :		17%	18%	10%	35%	17%	19%

Table 3.15 - Reservoir Properties for Field A[6]

	Field A	
Initial Pressure	2020	psi
Bubble Point Pressure	2020	psi
Initial Oil FVF	1.39	bbl / STB
Initial Gas FVF	150	scf / Sscf
Oil Viscosity	0.86	centipoise
Gas Viscosity	0.02	centipoise
Connate Water Sat.	11.5%	
Porosity	13%	
Thickness Bed	114	Ft
Permeability	31	md
Initial GOR	684	Scf / STB
Spacing	40	Acres

Table 3.16 - Well Test Information for Wells 3 and 14, Field A[6]

Well 3	Well 14
p_r = 1200 psi	p_r = 1410 psi
p_b = 2020 psi	p_b = 2020 psi
S = 0 (assumed)	S = 0 (assumed)

Test Data

p_{wf}	q_o, BOPD	p_{wf}	q_o, BOPD
1200	0	1410	0
1147	70	1170	72
1023	147	1050	118
856	209	888	155
612	280	632	208
530	292		

Tables 3.17 and 3.18 present the calculated results for Wells 3 and 14 predicted from pressure drawdown data of 29% and 38%, respectively. The calculation of parameters for the multirate methods are based on three data points. As can be seen from Figs. 3.9 and 3.10 all the predictions are relatively close for each method.

For Well 3, Fetkovich's method stands apart from the other methods. It predicts the two measured data points very well, as does Jones, Blount and Glaze. However, it provides a lower estimate of the AOF than the other methods. This is in contrast to Well 14 where all the methods predict the measured data points equally well and all yield similar AOFs. In addition, Fetkovich's method no longer has the lowest AOF prediction. Indeed, the order of the methods have changed from lowest to highest. This indicates the uncertainty of using one method over another even for wells in similar producing environments.

3.5 Cases 14 and 24

The next two wells analyzed were also presented by Fetkovich[6]. These wells were high rate, medium pressured wells producing from 9000 ft. The wells test data are presented in Table 3.19.

These wells had a limited maximum drawdown of approximately 20%, which limited the comparison over the entire pressure range. Both wells were analyzed at a pressure drawdown of 13%. As Figs. 3.11 and 3.12 and Tables 3.20 and 3.21 illustrate, there is a huge difference between the AOFs estimated by the different methods. However, all the methods estimated the measured data reasonably well. This resulted from the limited extrapolation from the test points.

Table 3.17 - Estimated Flow Rates for Well 3, Field A

Test Information :

q_o = 209 BOPD p_{wf} = 856 psi p_r = 1200 psi p_b = 2020 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
612	280	320	315	271	281	314	308
530	292	351	343	286	301	342	333
500	-	361	352	290	308	351	341
400	-	392	378	304	331	379	365
300	-	418	399	314	352	402	383
200	-	438	414	322	373	421	397
100	-	454	423	326	392	436	407
0	-	464	426	327	410	448	413

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
612	280	14%	12%	-3%	0%	12%	10%
530	292	20%	17%	-2%	3%	17%	14%
Average Difference :		17%	15%	3%	2%	15%	12%

Table 3.18 - Estimated Flow Rates for Well 14, Field A

Test Information :

q_o = 155 BOPD p_{wf} = 888 psi p_r = 1410 psi p_b = 2020 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
632	208	209	205	215	208	202	201
500	-	231	225	239	232	219	219
400	-	245	236	253	249	230	229
300	-	256	245	265	265	240	238
200	-	266	252	273	281	247	244
100	-	273	256	278	296	254	249
0	-	278	257	279	311	259	252

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
632	208	0.3%	-1.3%	3.4%	-0.1%	-3.1%	-3.1%

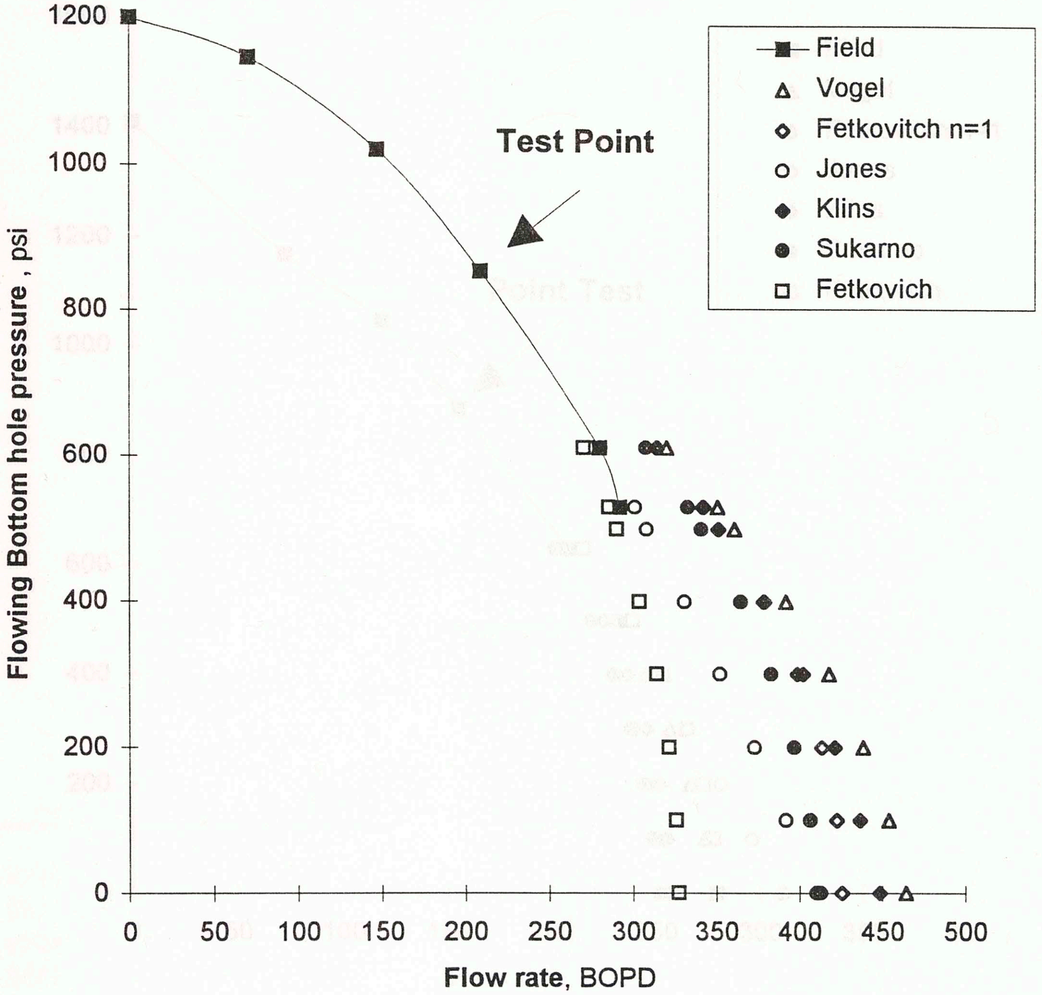

Fig. 3.9 - Performance curves for Well 3, Field A.

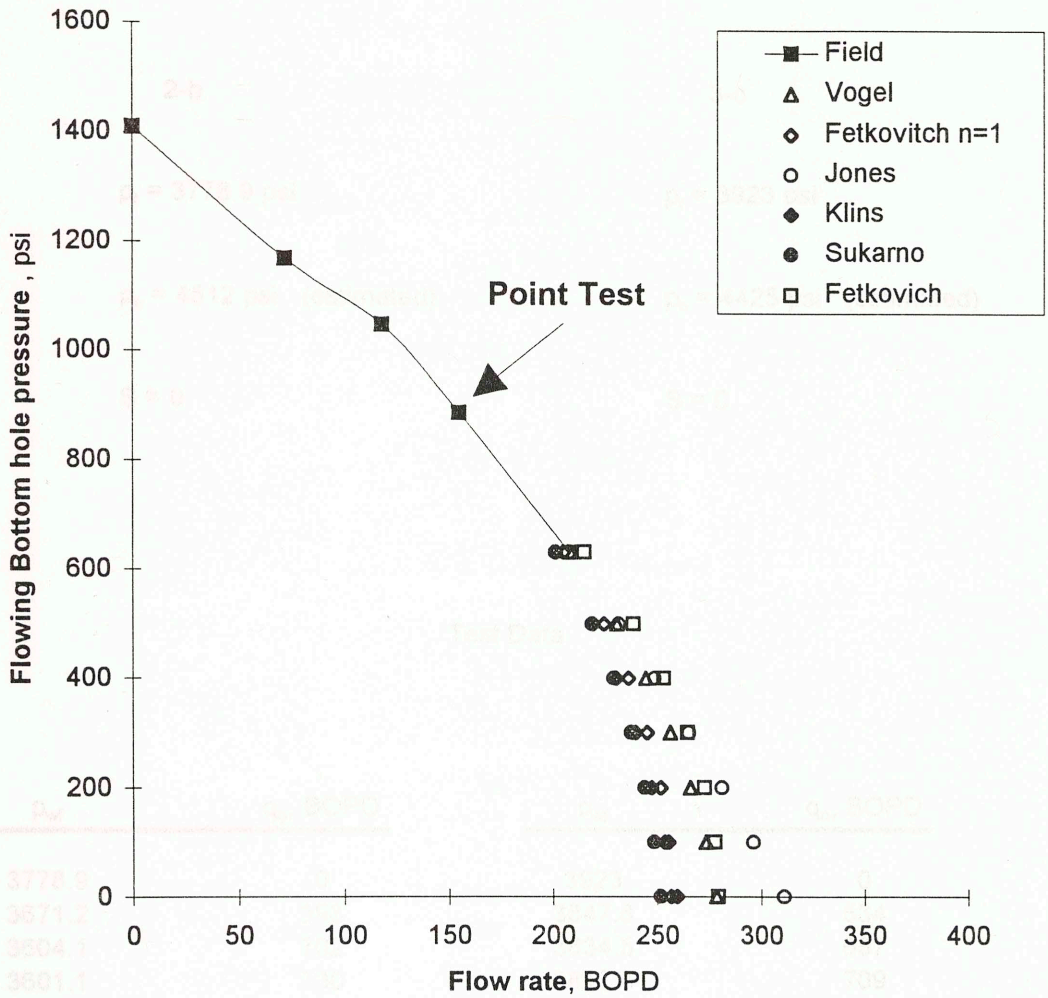

Fig. 3.10 - Performance curves for Well 14, Field A.

Table 3.19 - Well Test Information for Wells 2-b and 3-c, Field C[6]

2-b

p_r = 3778.9 psi

p_b = 4512 psi (estimated)

S = 0

3-c

p_r = 3923 psi

p_b = 4425 psi (estimated)

S = 0

Test Data

2-b

p_{wf}	q_o, BOPD
3778.9	0
3671.2	393
3604.1	702
3601.1	730
3430.7	1351
3198.4	2099
2979.1	2467
2973.5	2533

3-c

p_{wf}	q_o, BOPD
3923	0
3847.8	534
3834.5	687
3817.6	709
3811.5	711
3654.5	1390
3636.5	1394
3610.8	1535
3434.7	2010
3409.3	2064
3343.4	2077
3180.1	2518
3177.4	2520

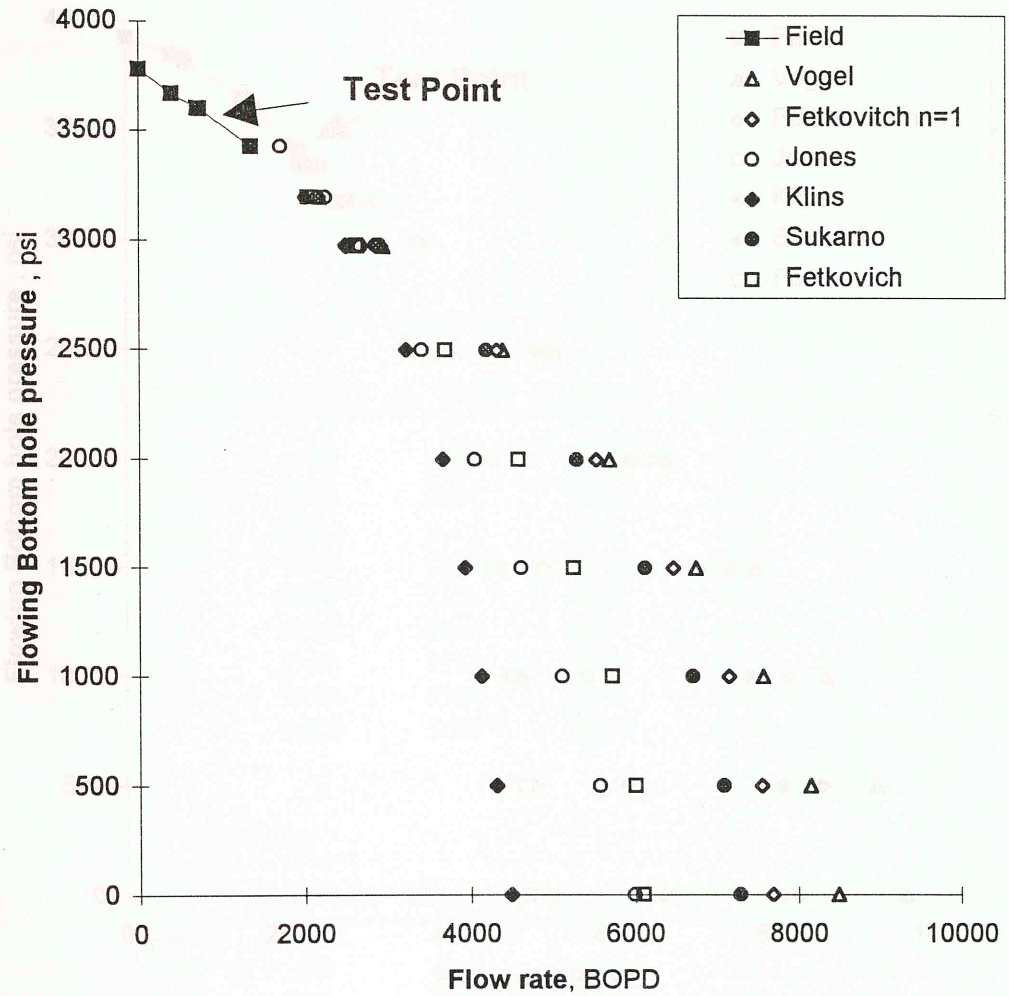

Fig. 3.11 - Performance curves for Well 2-b, Field C.

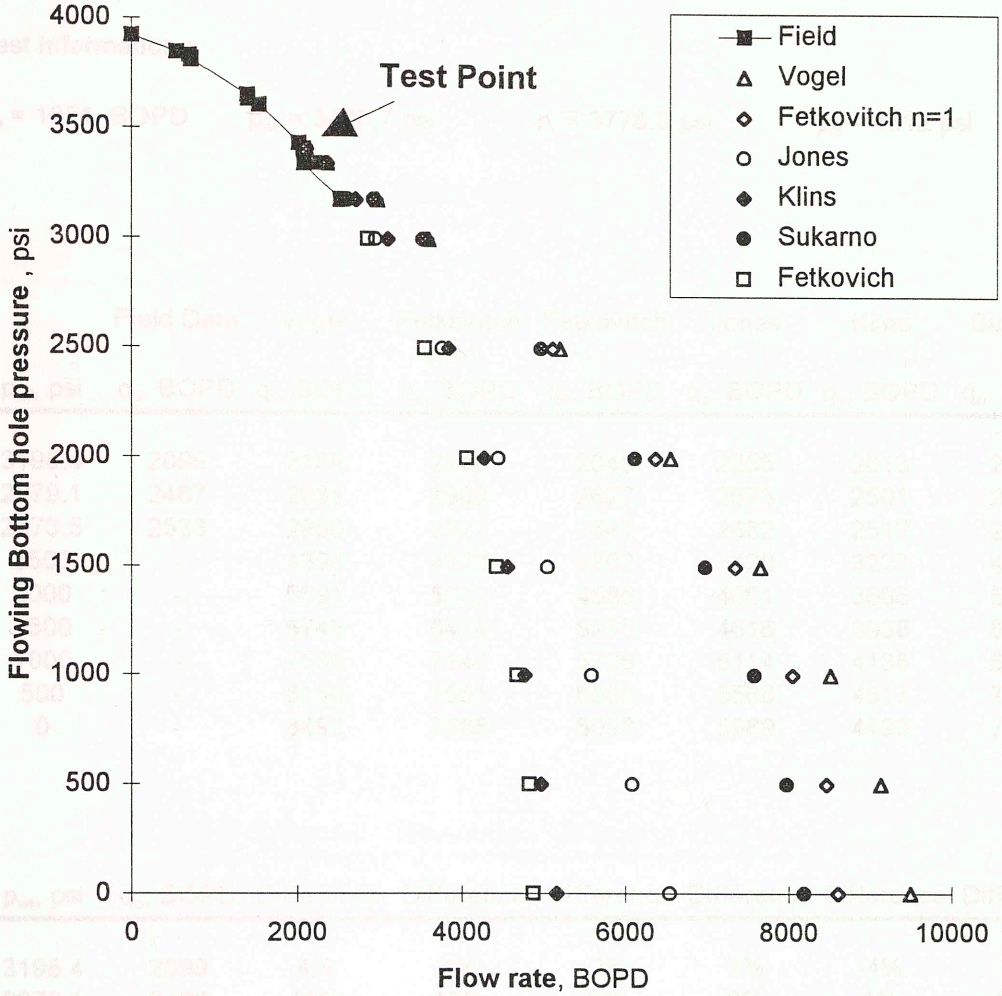

Fig. 3.12 - Performance curves for Well 3-c, Field C.

Table 3.20 - Estimated Flow Rates for Well 2-b, Field C

Test Information :

q_o = 1351 BOPD p_{wf} = 3430.7 psi p_r = 3778.9 psi p_b = 4512 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
3198.4	2099	2188	2180	2045	2255	2013	2164
2979.1	2467	2931	2909	2627	2673	2501	2869
2973.5	2533	2950	2927	2641	2682	2512	2886
2500	-	4396	4322	3702	3420	3227	4199
2000	-	5691	5532	4586	4061	3666	5299
1500	-	6748	6474	5255	4616	3938	6126
1000	-	7568	7147	5726	5114	4138	6711
500	-	8150	7551	6005	5568	4317	7087
0	-	8493	7685	6098	5989	4493	7288

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Differenc	Difference	Difference
3198.4	2099	4%	4%	-3%	7%	-4%	3%
2979.1	2467	19%	18%	6%	8%	1%	16%
2973.5	2533	16%	16%	4%	6%	-1%	14%
Average Difference :		13%	12%	4%	7%	2%	11%

Table 3.21 - Estimated Flow Rates for Well 3-c, Field C

Test Information :

q_o = 2010 BOPD $\quad$ p_{wf} = 3434.7 psi $\quad$ p_r = 3923 psi $\quad$ p_b = 4525 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
3409.3	2064	2108	2107	2069	2103	2089	2106
3343.4	2077	2360	2356	2214	2258	2284	2350
3180.1	2518	2965	2952	2541	2609	2711	2930
3177.4	2520	2974	2962	2546	2614	2718	2939
3000	-	3601	3575	2855	2954	3100	3529
2500	-	5201	5113	3551	3769	3846	4973
2000	-	6554	6372	4061	4450	4280	6114
1500	-	7660	7351	4430	5048	4558	6975
1000	-	8519	8051	4683	5588	4774	7586
500	-	9131	8470	4830	6083	4971	7981
0	-	9497	8610	4878	6543	5165	8196

p_{wf}, psi	q_o, BOPD	Differenc	Difference	Difference	Differenc	Differenc	Difference
3409.3	2064	2%	2%	0%	2%	1%	2%
3343.4	2077	14%	13%	7%	9%	10%	13%
3180.1	2518	18%	17%	1%	4%	8%	16%
3177.4	2520	18%	18%	1%	4%	8%	17%
Average Difference :		13%	13%	2%	4%	7%	12%

An interesting point appeared in this example. The single point method of Klins and Majcher yielded results similar to the multipoint methods and substantially different from Vogel's or Sukarno's methods. Evidently their bubble point correction has some influence at higher pressures near the bubble point, a condition they considered in developing their IPR.

3.6 Overall comparison

The preceding sections have presented a variety of comparisons for wells producing under different conditions. In total, 26 different cases have been examined with 8 presented in this chapter. The remaining 18 are shown in Appendix A.

Table 3.22 presents a summary of the average absolute difference for each method for all the wells examined. As indicated in this table, not one method always provided the most reliable estimates of the actual well data analyzed. However, some general comments can be made based on this table and the cases presented in this study.

The multipoint methods tends to do a better job of predicting performance than the single point methods. As a matter of fact, the total average absolute difference is almost twice as great for the single point methods in comparison to Fetkovich's multipoint method, 15% compared to 8%. Overall, the single point method of Vogel, Fetkovich, and Sukarno provided similar average differences in the cases examined while Klins and Majcher was only slightly better.

Table 3.23 presents a ranking of the IPR methods. This rank is only based on the arithmetic average of the absolute difference for the 26 tests analyzed in this study.

Table 3.22 - Comparison of the Absolute Difference for Each Method

Case	Vogel % Difference	n=1 Fetkovitch % Difference	Fetkovitch % Difference	Jones % Difference	Klins % Difference	Sukarno % Difference
1	31%	26%	4%	7%	18%	22%
2	15%	13%	6%	6%	7%	11%
3	17%	16%	6%	10%	13%	15%
4	9%	9%	10%	10%	11%	10%
5	4%	5%	21%	5%	9%	6%
6	5%	6%	20%	5%	12%	8%
7	18%	18%	9%	31%	24%	20%
8	14%	15%	2%	21%	18%	16%
9	16%	17%	17%	58%	16%	18%
10	17%	18%	10%	35%	17%	19%
11	12%	13%	11%	14%	12%	14%
12	11%	12%	11%	21%	13%	13%
13	17%	15%	3%	2%	15%	12%
14	13%	13%	2%	4%	7%	12%
15	0%	1%	3%	0%	3%	3%
16	38%	38%	15%	15%	33%	38%
17	19%	18%	6%	13%	16%	18%
18	8%	9%	18%	22%	13%	9%
19	3%	2%	1%	0%	1%	1%
20	51%	51%	4%	15%	40%	50%
21	27%	27%	9%	13%	21%	26%
22	20%	19%	2%	1%	17%	19%
23	2%	4%	5%	2%	4%	5%
24	13%	12%	4%	7%	2%	11%
25	17%	17%	3%	5%	13%	17%
26	5%	5%	11%	2%	2%	5%
Avg.	15%	15%	8%	12%	14%	15%

Thus if somebody considers case 9, one notices that the order or rank of the methods have been reversed as the single point methods predicted the flow rates with more accuracy.

Another parameter which has not been considered in this ranking criteria is the aspect of conducting the tests. It is evident that test costs have to be taken into consideration. For example, in a low permeability oil reservoir , the cost for conducting a multipoint test would be large compared to the single point test. So under these conditions, it may be preferable to run a single point test to predict the performance of the individual well.

Table 3.23 - Ranking of the IPR Methods Based on this Study

Method	Rank
Fetkovich (multipoint)	1
Jones, Blount and Glaze	2
Klins and Majcher	3
Sukarno, Vogel, Fetkovich (single point)	4

CHAPTER 4

CONCLUSIONS AND RECOMMENDATIONS

In this study, five different methods to predict the pressure-production performance of oil wells producing from solution-gas drive reservoirs have been presented. These are the methods of Vogel, Fetkovich, Jones, Blount and Glaze, Klins and Majcher, and finally Sukarno methods. Each of them require parameters that are normally available from a production test. The methods can be separated into multipoint methods and single point methods.

The primary concern in this study was to evaluate the reliability of the IPR methods based on actual production test data. Detailed analysis and comparisons for five different cases were presented in Chapter 3 while additional cases were presented in Appendix A. From this study the following conclusions are presented.

1. There is no one method which is the most suitable for every test. It has been observed that in one case method A will provide the most reliable estimates while providing the worst estimates in the next case. From this observation, consideration should be given for using more than one method in predicting performance in order to provide a range of possible outcomes.

2. Overall, Fetkovich 's multipoint method tended to be the most reliable. It has been shown based on all the test data of this study that the overall absolute difference for Fetkovich's method was less than the other. Also, Fetkovich's method provided

steady performance predictions throughout the pressure drawdown range while the single point methods appeared to be more sensitive to the drawdown pressure of the test point.

3. Due to the effects of depletion, one IPR method may be more reliable at one reservoir pressure but not at the second pressure. This may be caused by changes in reservoir with time which can lead to changes in its flow properties.

NOMENCLATURE

A	= variable in Uhri and Blount method, BOPD/psi
A'	= variable in Kelkar and Cox method, BOPD/psi^3
B'	= variable in Kelkar and Cox method, BOPD/psi
C	= Fetkocivh's coefficient, BOPD/$(psi)^{2n}$
C	= Jones *et al.'s* laminar flow coefficient, psi/BOPD
D	= Jones *et al.'s* turbulence flow coefficient, psi/$BOPD^2$
d	= Klins and Majcher flow exponent
J^*	= Standing's modified productivity index, BOPD/psi
J^*	= Kelkar and Cox's modified productivity index, BOPD/psi
n	= Fetkovich's flow exponent
n	= variable in Uhri and Blount method, psi
p_b	= bubble point pressure, psi
p_{wf}	= flowing bottomhole pressure, psi
p_r	= average reservoir pressure, psi
q_o	= oil production rate, BOPD
q_{omax}	= maximum oil production rate, BOPD
r_e	= external drainage raduis, ft
r_w	= well raduis, ft
h	= producing formation thickness, ft
S	= skin effect excluding turbulaence effects
ρ	= density, lb_m/cu.ft

k = permeability, md

β = turbulence factor, ft^{-1}

μo = oil viscosity, cp

Bo = oil formation volume factor, RB/STB

Subscripts

f = future reservoir conditions

p = present reservoir conditions

o = oil phase

g = gas phase

1 = test 1

2 = test 2

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APPENDIX A

Table A.1 - Estimated Flow Rates for Well B, Keokuk Field, OK December 1934

Test Information :

q_o = 280 BOPD $\quad$ p_{wf} = 1583 psi $\quad$ p_r = 1714 psi $\quad$ p_b = 3420 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1443	508	557	555	523	517	538	549
1272	780	866	856	776	769	801	838
1196	1125	992	977	877	871	902	952
982	1335	1312	1279	1121	1132	1135	1229
950	-	1356	1319	1153	1168	1164	1265
900	-	1421	1379	1201	1224	1208	1318
800	-	1543	1490	1288	1331	1285	1415
700	-	1654	1587	1365	1434	1351	1500
600	-	1753	1671	1431	1532	1408	1573
500	-	1841	1742	1487	1627	1457	1635
400	-	1917	1801	1532	1719	1498	1687
300	-	1981	1846	1567	1808	1535	1728
200	-	2035	1879	1592	1894	1567	1761
100	-	2077	1898	1607	1978	1596	1786
0	-	2107	1905	1612	2059	1625	1803

p_{wf}, psi	q_o, BOPD	Differenc	Difference	Difference	Differenc	Differenc	Difference
1443	508	10%	9%	3%	2%	6%	8%
1272	780	11%	10%	0%	-1%	3%	7%
1196	1125	-12%	-13%	-22%	-23%	-20%	-15%
982	1335	-2%	-4%	-16%	-15%	-15%	-8%
Average Difference		9%	9%	10%	10%	11%	10%

Table A.2 - Estimated Flow Rates for Well B, Keokuk Field, OK, August 1935

Test Information :

q_o = 420 BOPD p_{wf} = 1381 psi p_r = 1605 psi p_b = 3538 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1231	720	670	666	576	679	647	659
1120	850	839	830	669	806	790	814
1100	-	868	858	684	827	813	840
1000	-	1007	990	754	929	922	963
900	-	1134	1109	815	1024	1017	1071
800	-	1250	1216	868	1112	1099	1167
700	-	1356	1310	914	1195	1169	1250
600	-	1450	1392	952	1274	1229	1322
500	-	1533	1461	984	1349	1280	1382
400	-	1605	1517	1010	1421	1323	1432
300	-	1666	1561	1030	1490	1360	1472
200	-	1716	1592	1044	1557	1392	1503
100	-	1755	1611	1053	1622	1421	1526
0	-	1782	1618	1055	1684	1447	1543

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
1231	720	-7%	-7%	-20%	-6%	-10%	-9%
1120	850	-1%	-2%	-21%	-5%	-7%	-4%
Average Difference		4%	5%	21%	5%	9%	6%

Table A.3 - Estimated Flow Rates for Well C, Lucien Field, OK

Test Information :

q_o = 510 BOPD $\quad$ p_{wf} = 1615 psi $\quad$ p_r = 1825 psi $\quad$ p_b = 3640 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1410	960	955	948	1148	952	904	935
1195	1500	1365	1343	1812	1377	1224	1308
1100	-	1528	1497	2089	1555	1339	1449
1000	-	1687	1645	2363	1736	1445	1583
900	-	1834	1780	2619	1911	1537	1703
800	-	1969	1900	2852	2081	1616	1808
700	-	2091	2005	3062	2246	1684	1901
600	-	2200	2097	3247	2407	1742	1981
500	-	2297	2175	3406	2564	1793	2048
400	-	2382	2238	3536	2718	1837	2105
300	-	2454	2288	3639	2867	1876	2151
200	-	2513	2323	3713	3014	1912	2188
100	-	2560	2344	3757	3157	1945	2216
0	-	2595	2351	3772	3298	1977	2236

p_{wf}, psi	q_o, BOPD	Differenc	Difference	Difference	Differenc	Difference	Difference
1410	960	-1%	-1%	20%	-1%	-6%	-3%
1195	1500	-9%	-10%	21%	-8%	-18%	-13%
Average Difference		5%	6%	20%	5%	12%	8%

Table A.4 - Estimated Flow Rates for Well E, Lucien Field, OK

Test Information :

q_o = 515 BOPD p_{wf} = 1727 psi p_r = 1845 psi p_b = 3814 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1645	975	855	853	944	790	836	849
1525	1590	1327	1318	1593	1222	1255	1301
1400	-	1785	1764	2262	1646	1632	1728
1200	-	2447	2400	3273	2279	2124	2321
1000	-	3023	2937	4173	2867	2499	2808
800	-	3513	3377	4935	3418	2780	3195
700	-	3725	3560	5259	3681	2893	3354
600	-	3915	3719	5542	3938	2989	3491
500	-	4084	3854	5783	4188	3073	3608
400	-	4232	3964	5982	4432	3146	3706
300	-	4357	4049	6138	4670	3211	3786
200	-	4461	4110	6249	4904	3271	3849
100	-	4544	4147	6316	5132	3326	3897
0	-	4604	4159	6339	5355	3381	3932

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
1645	975	-12%	-13%	-3%	-19%	-14%	-13%
1525	1590	-17%	-17%	0%	-23%	-21%	-18%
Average Difference		14%	15%	2%	21%	18%	16%

Table A.5 - Estimated Flow Rates for Well F, South Burkbank Field, OK

Test Information :

q_o = 130 BOPD p_{wf} = 838 psi p_r = 903 psi p_b = 2985 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
750	228	292	291	350	138	292	287
719	362	346	343	429	161	345	338
718	382	347	344	431	162	347	339
710	385	361	358	451	168	360	352
709	394	363	359	454	169	362	353
697	453	382	379	484	177	382	372
650	583	458	451	601	211	457	441
582	858	558	548	762	256	557	530
500	-	667	650	940	306	665	622
400	-	782	753	1128	363	780	714
300	-	876	833	1278	417	875	783
200	-	950	891	1387	466	951	834
100	-	1003	925	1453	513	1009	867
0	-	1036	937	1475	558	1051	886

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
750	228	28%	27%	53%	-40%	28%	26%
719	362	-4%	-5%	18%	-55%	-5%	-7%
718	382	-9%	-10%	13%	-58%	-9%	-11%
710	385	-6%	-7%	17%	-56%	-6%	-9%
709	394	-8%	-9%	15%	-57%	-8%	-10%
697	453	-16%	-16%	7%	-61%	-16%	-18%
650	583	-22%	-23%	3%	-64%	-22%	-24%
582	858	-35%	-36%	-11%	-70%	-35%	-38%
Average Difference		16%	17%	17%	58%	16%	18%

Table A.6 - Estimated Flow Rates for Well H, South Burkbank Field, OK

Test Information :

q_o = 238 BOPD p_{wf} = 724 psi p_r = 898 psi p_b = 2985 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
674	324	298	297	301	282	298	295
646	349	330	328	334	316	330	325
556	485	425	419	433	423	425	410
524	583	456	448	465	461	455	437
500	-	478	469	488	489	478	456
400	-	562	545	572	603	561	524
300	-	630	604	637	714	630	576
250	-	659	627	663	769	660	596
200	-	684	646	685	823	686	613
150	-	705	661	701	877	709	627
100	-	723	672	713	930	728	638
50	-	737	678	720	982	745	647
0	-	747	680	722	1034	758	653

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
674	324	-8%	-8%	-7%	-13%	-8%	-9%
646	349	-5%	-6%	-4%	-9%	-5%	-7%
556	485	-12%	-14%	-11%	-13%	-12%	-15%
524	583	-22%	-23%	-20%	-21%	-22%	-25%
Average Difference :		12%	13%	11%	14%	12%	14%

Table A.7 - Estimated Flow Rates for Well 6, Field A

Test Information :

q_o = 93 BOPD p_{wf} =1178 psi p_r = 1345 psi p_b = 2020 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1142	134	112	111	112	106	111	111
1123	137	121	121	122	113	120	120
921	229	215	212	219	171	208	207
900	-	224	221	228	176	215	215
800	-	263	258	268	200	250	250
700	-	299	291	304	221	281	280
600	-	331	320	335	241	307	305
500	-	359	344	362	260	330	326
400	-	383	364	383	278	349	344
300	-	403	379	400	295	365	357
200	-	420	390	412	311	378	368
100	-	432	397	420	326	388	375
0	-	440	399	422	341	398	380
0	-	496	448	448	499	444	424

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
1142	134	-17%	-17%	-16%	-21%	-17%	-17%
1123	137	-11%	-12%	-11%	-18%	-12%	-12%
921	229	-6%	-7%	-4%	-25%	-9%	-9%
Average Difference		11%	12%	11%	21%	13%	13%

Table A.8 - Estimated Flow Rates for Well 5, Field D

Test Information :

q_o = 757 BOPD p_{wf} = 3658.4 psi p_r = 3695.5 psi p_b = 4525 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
3604	1452	1855	1853	1289	1331	1817	1850
3524.3	2308	3437	3430	1858	1829	3268	3416
3000	-	13062	12921	4087	3708	10291	12659
2500	-	20980	20551	5385	4868	14079	19819
2000	-	27665	26794	6304	5801	16229	25456
1500	-	33117	31649	6960	6604	17532	29694
1000	-	37337	35118	7404	7320	18469	32681
500	-	40324	37199	7661	7972	19291	34588
0	-	42079	37892	7746	8575	20093	35606

p_{wf}, psi	q_o, BOPD	Differenc	Difference	Difference	Differenc	Differenc	Difference
3604	1452	28%	28%	-11%	-8%	25%	27%
3524.3	2308	49%	49%	-19%	-21%	42%	48%
Average Difference		38%	38%	15%	15%	33%	38%

Table A.9 - Estimated Flow Rates for Well 6, Field D

Test Information :

q_o = 1035 BOPD p_{wf} = 3535.1 psi p_r = 3598.6 psi p_b = 4525 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
3513.7	1413	1380.1	1379.7	1273.0	1544.1	1369.1	1378.7
3430.9	2003	2697.9	2693.5	2060.7	2355.2	2595.0	2684.8
3000	-	9106.8	9024.9	4921.5	4901.4	7500.3	8872.5
2500	-	15599.1	15308.1	7199.9	6833.4	10907.8	14806.5
2000	-	21076.9	20449.0	8868.8	8358.1	12829.8	19474.3
1500	-	25540.2	24447.4	10085.8	9658.7	13968.6	22976.6
1000	-	28989.0	27303.4	10920.9	10812.1	14761.5	25437.3
500	-	31423.4	29017.0	11410.2	11859.2	15441.8	27000.5
0	-	32843.3	29588.2	11571.5	12824.8	16102.5	27826.2

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
3513.7	1413	-2%	-2%	-10%	9%	-3%	-2%
3430.9	2003	35%	34%	3%	18%	30%	34%

Average Difference :		19%	18%	6%	13%	16%	18%

Table A.10 - Estimated Flow Rates for Well 1, Field E

Test Information :

q_o = 1601 BOPD p_{wf} = 3541.5 psi p_r = 3695.3 psi p_b = 4964 psi

p_{wf}, psi	Field Data q_o, BOPD	Vogel q_o, BOPD	Fetkovitch n =1 q_o, BOPD	Fetkovitch q_o, BOPD	Jones q_o, BOPD	Klins q_o, BOPD	Sukarno q_o, BOPD
3504.4	2125	1978.2	1977.0	1899.3	1799.4	1950.5	1974.8
3424.4	3028	2779.5	2774.3	2499.2	2364.5	2659.1	2764.4
3423.5	3117	2788.4	2783.2	2505.6	2370.5	2666.7	2773.2
3366.9	3658	3345.4	3336.0	2901.7	2734.1	3132.4	3318.2
3360.4	3689	3408.8	3398.9	2945.9	2774.3	3184.0	3380.1
3000	-	6757.5	6696.2	5102.2	4664.4	5542.7	6583.9
2500	-	10854.6	10651.9	7431.1	6671.3	7563.7	10308.8
2000	-	14313.9	13888.4	9212.6	8316.5	8703.4	13241.7
1500	-	17135.4	16405.6	10543.4	9745.0	9393.0	15446.3
1000	-	19319.1	18203.7	11470.0	11024.9	9891.4	17000.2
500	-	20865.0	19282.5	12017.6	12194.8	10330.7	17992.4
0	-	21773.1	19642.1	12198.8	13278.9	10760.5	18521.9

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Differenc	Differenc	Difference
3504.4	2125	-7%	-7%	-11%	-15%	-8%	-7%
3424.4	3028	-8%	-8%	-17%	-22%	-12%	-9%
3423.5	3117	-11%	-11%	-20%	-24%	-14%	-11%
3366.9	3658	-9%	-9%	-21%	-25%	-14%	-9%
3360.4	3689	-8%	-8%	-20%	-25%	-14%	-8%
Average Difference :		8%	9%	18%	22%	13%	9%

Table A.11 - Estimated Flow Rates for Well TMT-27, Miring Timur Field, Indonesia

Test Information :

q_o = 262 BOPD p_{wf} = 492 psi p_r = 868 psi p_b = 5340 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
419	290	298	296	291	292	293	294
350	320	328	323	314	320	317	318
300	-	348	340	328	339	333	333
250	-	365	354	340	357	346	346
200	-	379	366	350	375	357	357
150	-	392	374	357	392	367	365
100	-	402	381	363	408	375	372
50	-	410	385	366	424	383	377
0	-	416	386	367	439	389	381

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
419	290	3%	2%	0%	1%	1%	1%
350	320	3%	1%	-2%	0%	-1%	-1%
Average Difference :		3%	2%	1%	0%	1%	1%

Table A.12 - Estimated Flow Rates for Well 1, Field F

Test Information :

q_o = 1398 BOPD p_{wf} = 3306.5 psi p_r = 3420.2 psi p_b = 4029 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
3199.6	2140	2674	2669	2061	2380	2573	2660
3062.6	2777	4255	4237	2719	3116	3900	4203
3002	2800	4935	4909	2970	3395	4429	4860
3000	-	4958	4931	2978	3404	4446	4881
2500	-	10111	9958	4540	5195	7682	9689
2000	-	14453	14070	5587	6535	9510	13465
1500	-	17984	17269	6318	7653	10561	16288
1000	-	20705	19554	6807	8634	11248	18261
500	-	22614	20925	7089	9517	11806	19501
0	-	23713	21382	7182	10328	12339	20144
0	-	25239	22745	13082	18192	12160	21405

p_{wf}, psi	q_o, BOPD	Differenc	Difference	Difference	Differenc	Differenc	Difference
3199.6	2140	25%	25%	-4%	11%	20%	24%
3062.6	2777	53%	53%	-2%	12%	40%	51%
3002	2800	76%	75%	6%	21%	58%	74%
Average Difference :		51%	51%	4%	15%	40%	50%

Table A.13 - Estimated Flow Rates for Well 2, Field F

Test Information :

q_o = 1493 BOPD p_{wf} = 3597.9 psi p_r = 3693.8 psi p_b = 4056 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
3513.4	2344	2780	2776	2161	2712	2694	2769
3500	3088	4182	4170	2754	3411	3917	4148
3419.2	-	10015	9916	4615	5590	8099	9733
3000	-	16102	15787	6088	7425	11115	15252
2500	-	21241	20591	7133	8900	12835	19598
2000	-	25432	24327	7878	10170	13878	22865
1500	-	28676	26996	8383	11302	14625	25167
1000	-	30972	28597	8675	12333	15277	26637
500	-	32321	29131	8772	13286	15913	27422
0	-	33571	30225	4945	11038	16100	28391

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
3513.4	2344	19%	18%	-8%	16%	15%	18%
3500	3088	35%	35%	-11%	10%	27%	34%
Average Difference :		27%	27%	9%	13%	21%	26%

Table A.14 - Estimated Flow Rates for Well A

Test Information :

q_o = 643 BOPD p_{wf} = 1725 psi p_r = 1785 psi p_b = 2056 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
1643	1298	1490	1486	1267	1268	1461	1479
1602	1524	1900	1892	1541	1527	1846	1878
1400	-	3787	3744	2677	2555	3508	3666
1200	-	5437	5332	3563	3352	4814	5153
1000	-	6871	6675	4274	4029	5828	6371
800	-	8088	7774	4836	4628	6600	7339
600	-	9088	8629	5262	5171	7176	8077
400	-	9872	9240	5561	5672	7604	8610
200	-	10438	9606	5739	6139	7934	8963
100	-	10641	9698	5783	6362	8077	9081
0	-	10789	9728	5798	6578	8214	9165

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
1643	1298	15%	15%	-2%	-2%	13%	14%
1602	1524	25%	24%	1%	0%	21%	23%
Average Difference :		20%	19%	2%	1%	17%	19%

Table A.15 - Estimated Flow Rates for Well 8, West Texas Area

Test Information :

q_o = 216 BOPD p_{wf} = 552 psi p_r = 640 psi p_b = 3560 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
397	507	528	519	545	521	535	504
232	770	764	733	785	786	788	695
200	-	799	761	817	833	827	720
150	-	845	797	858	903	880	752
100	-	882	823	887	971	925	776
50	-	910	838	905	1036	962	793
0	-	930	843	911	1100	989	804

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
397	507	4%	2%	8%	3%	6%	0%
232	770	-1%	-5%	2%	2%	2%	-10%
Average Difference :		2%	4%	5%	2%	4%	5%

Table A.16 - Estimated Flow Rates for Well 4, Field C

Test Information :

q_o = 1403 BOPD p_{wf} = 4242.2 psi p_r = 4342.8 psi p_b = 4735 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
4154.2	2167	2606	2603	2203	2123	2519	2597
4152.5	2303	2629	2626	2217	2133	2540	2620
4000	-	4661	4646	3363	2879	4249	4617
3500	-	10852	10738	6198	4542	8262	10529
3000	-	16322	16017	8300	5745	10588	15495
2500	-	21070	20485	9932	6739	11941	19562
2000	-	25098	24140	11197	7605	12787	22788
1500	-	28405	26983	12145	8382	13404	25243
1000	-	30990	29013	12806	9093	13936	27008
500	-	32854	30232	13196	9753	14446	28172
0	-	33998	30638	13325	10371	14954	28831

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
4154.2	2167	20%	20%	2%	-2%	16%	20%
4152.5	2303	14%	14%	-4%	-7%	10%	14%
Average Difference :		17%	17%	3%	5%	13%	17%

Table A.17 - Estimated Flow Rates for Well 4, Field D

Test Information :

q_o = 1465 BOPD $\quad$ p_{wf} = 3373.7 psi $\quad$ p_r = 3486.3 psi $\quad$ p_b = 3502 psi

	Field Data	Vogel	Fetkovitch n =1	Fetkovitch	Jones	Klins	Sukarno
p_{wf}, psi	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD	q_o, BOPD
3310.6	2203	2267	2265	1981	2279	2217	2260
3304	2271	2350	2348	2031	2333	2292	2342
3273.6	2574	2732	2727	2253	2567	2635	2718
3264.8	2626	2841	2836	2315	2632	2733	2826
3000	-	6021	5982	3881	4206	5280	5910
2500	-	11382	11198	5991	6279	8484	10877
2000	-	15902	15465	7493	7869	10304	14781
1500	-	19580	18784	8572	9209	11364	17703
1000	-	22417	21155	9308	10390	12071	19749
500	-	24412	22578	9737	11457	12654	21040
0	-	25566	23052	9878	12439	13214	21714
0	-	28332	25509	4608	10330	14276	23963
0	-	25239	22745	13082	18192	12160	21405

p_{wf}, psi	q_o, BOPD	Difference	Difference	Difference	Difference	Difference	Difference
3310.6	2203	3%	3%	-10%	3%	1%	3%
3304	2271	3%	3%	-11%	3%	1%	3%
3273.6	2574	6%	6%	-12%	0%	2%	6%
3264.8	2626	8%	8%	-12%	0%	4%	8%
Average Difference :		5%	5%	11%	2%	2%	5%