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GAS PRODUCTION FORECASTING USING AUTOMATIC TYPE CURVE MATCHING

Jonathan Diazgranados

Thesis submitted to the
College of Engineering and Mineral Resources
at West Virginia University
in partial fulfillment of the requirements
for the degree of

Master of Science
In
Petroleum and Natural Gas Engineering

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2000

Keywords: Gas Production, Type Curves, Gas wells, Gas Production Forecasting, Gas Production Simulation
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ABSTRACT

Gas Production Forecasting Using Automatic Type Curve Matching

Jonathan Diazgranados

As the demand for natural gas has increased in the last years, also the need for forecast reliable gas recoveries. Gas type curves are one of the methods utilized to estimate future well performance. The purpose of this study is the utilization of the Aminian et al type curves to model gas well performance. Unlike other studies developed in the past, Aminian et al type curves account for important factors ignored in the derivation of the proposed theoretical solutions. Thus, the pressure dependency of gas viscosity and compressibility, as well as the pressure loss owing to non Darcy flow, make of these solutions quite accurate to model gas wells decline.

Different history productions were matched with these type curves using a computer program, which find the closest production decline to the available time/gas rate. In order to find the matched type curve, the program iterate on non-Darcy effects, bottom hole flowing pressure, and initial gas in place, which are the required variables to generate a type curve. The consistency of the computer program was verified by using gas productions of 25%, 50% and 75% of the total gas production of gas wells with moderate and low permeabilities. Satisfactory predictions were obtained for the different scenarios analyzed, finding the prediction of the bottom hole flowing pressure sensible to the amount of data utilized for the predictions.

ACKNOWLEDGMENTS

I would like to express my gratitude to West Virginia University and the chairman of the Petroleum and Natural Gas Engineering Department, Sam Ameri for their contributions and help in the attainment of my graduate studies.

Also, I want to thank Dr. Khashayar Aminian for his guidance and assistance in providing me the necessary background to make possible this study.

Likewise, I extend my gratitude to Dr. Ilkin Bilgesu and Dr. Daniel Della-Giustina for their support and participation in the examining committee.

Finally, I would like to thank my parents Walter, and Ada for their unselfish love and support throughout my life and college career. I could never repay you.

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NOMENCLATURE

a	Darcy flow coefficient, $psi^2/(cp)(Mscf/D)$
ALSD	Average least square difference
b	Non- Darcy flow coefficient, $psi^2/(cp)(Mscf/D)^2$
$\boldsymbol{b}$	Arps decline – curve constant
β	Turbulence coefficient, ft^{-1}
C	Performance coefficient
C_g	Gas compressibility, psi^{-1}
C_{gi}	Gas compressibility at Pi, psi^{-1}
CA	Reservoir shape factor, dimensionless
D	Decline rate, day^{-1}
F_{NDi}	Non-Darcy flow ratio, dimensionless
F_{taD}	pseudotime ratio, dimensionless
Gp	Gas produced, Mscf
Gi	Initial gas in place, Bcf
G_D	Dimensionless cumulative production
h	Reservoir average thickness, ft
K	Formation permeability, md
L	Draw-down parameter
n	Exponent in back-pressure equation, dimensionless
Pwf	Bottom-hole flowing pressure, psia
P_R	Initial reservoir pressure in back-pressure equation, psia
Pi	Initial Reservoir Pressure, psia
P_p	Pseudopressure, psi^2/cp
P	Pressure, psia
$q(t)$	Gas flow rate at time t, Mscf/D
q_i	Initial surface gas flow rate at t=0, Mscf/D

q	Flow rate, Mscf/D
q_D	Dimensionless flow rate
$\bar{q}$	Average flow rate, Mscf/D
r_w	Wellbore radius, ft
s	Skin Factor, dimensionless
S	Standard deviation, dimensionless
t	Time, days
T	Reservoir temperature, Fahrenheit degrees
t_D	Dimensionless time
μ	Gas viscosity, cp
μgi	Gas viscosity at Pi, psia
$\bar{\mu}$	Average viscosity, cp
X_i	Dimensionless term
λ	Drawdown parameter Carter equation
γ	Gas gravity, dimensionless
z	Gas deviation factor, dimensionless

CHAPTER 1

INTRODUCTION

As a part of a gas reservoir development, one of the most important requirements is to estimate and forecast gas recoveries and production rates for individual wells or entire fields. Different techniques have been developed in the past to obtain this information. The utilization of these methods will depend of the economic risk associated with the forecast and the availability of the data necessary for the method being applied. Also, considerations as time constraints, availability of certain models, or the familiarity of the engineer may have with different forecasting methods may be the governing factor in deciding which method might be applied.

Generally, only information about production rates versus time (production history) is available to initiate any evaluation of the reservoir currently on study. Among the techniques used for this purpose, type curves have been found quite accurate to forecast gas well performance in absence of known reservoir parameters.

The aim of this study is to predict future gas wells deliverability using the solutions proposed by Aminian[1] et al type curves. These type curves were introduced in 1986, and account for a number of factors, which have been ignored in the derivation of

other type curves. A computer program in Visual Basic 6.0 has been developed to predict future gas well recoveries by matching the available production history with the best possible decline behavior for it. As a result, the computer program allows finding the closest gas decline to the available one by iterating on Xi, F_{NDi}, and Gi, which are the parameters that define type curves.

The results obtained were verified for a wide range of reservoir characteristics using 25%, 50%, 75% of the total production histories to be compared with their respective forecast. Good results were obtained for the three variables in studies, finding *Pwf* as the most impacting variable in the prediction of future gas production rates.

CHAPTER 2

BACKGROUND AND THEORY

This chapter discusses the general theory about production decline analysis for gas wells. In order to do a prediction of future gas production in a well, it is necessary to analyze the behavior exhibited by the available production history or time versus cumulative production. Basically, a match of the production history with a "decline model" is performed, assuming that the future productions will follow the observed past trend. Using these models, the original gas in place of the reservoir is estimated and with this estimation, gas reserves at some future pressures or economic production rates are predicted. This chapter presents a brief summary of the classical decline curve fitting and the published gas well type curves for gas production forecasting.

2. 1 Conventional Decline Techniques

Conventional decline curve analysis is based on empirical equations developed by Arps[2]. Although his work was based on oil production data, the equations were also found applicable to volumetric dry gas reservoirs. Arps found three types of decline curves defined as exponential or constant percentage decline, harmonic, and hyperbolic decline. The general form of Arps's equation is:

$$q(t) = \frac{q_i}{(1 + bDt)^{1/b}} \qquad (2.1)$$

Where D is defined as the decline constant in days^{-1}, q_i is the initial gas flow rate in Mscf/D, q is the flow rate to any time, t is time in days, and b is the depletion stem which defines any of the three type of decline according to its value. These forms of decline have a different shape according to the type of scale used to graph the available gas production. As figure 2.1 shows, the response of the decline curve according to the Cartesian or semilog graphs of gas production rate vs. time and gas production rate vs. cumulative gas production will allow to diagnostic the type of analysis to be applied.

It is important to highlight that these decline forms have some assumptions to follow. Basically, any changes in the field development or production operation could change the future performance of a well and in that way will affect reserve estimations. Arp's equations assume that the well is produced at the same flowing pressure *Pwf*, constant reservoir drainage area, constant reservoir permeability and skin factor. Therefore, any change in these parameters during the life of the well will change the character of the decline and should be accounted to avoid erroneous analysis.

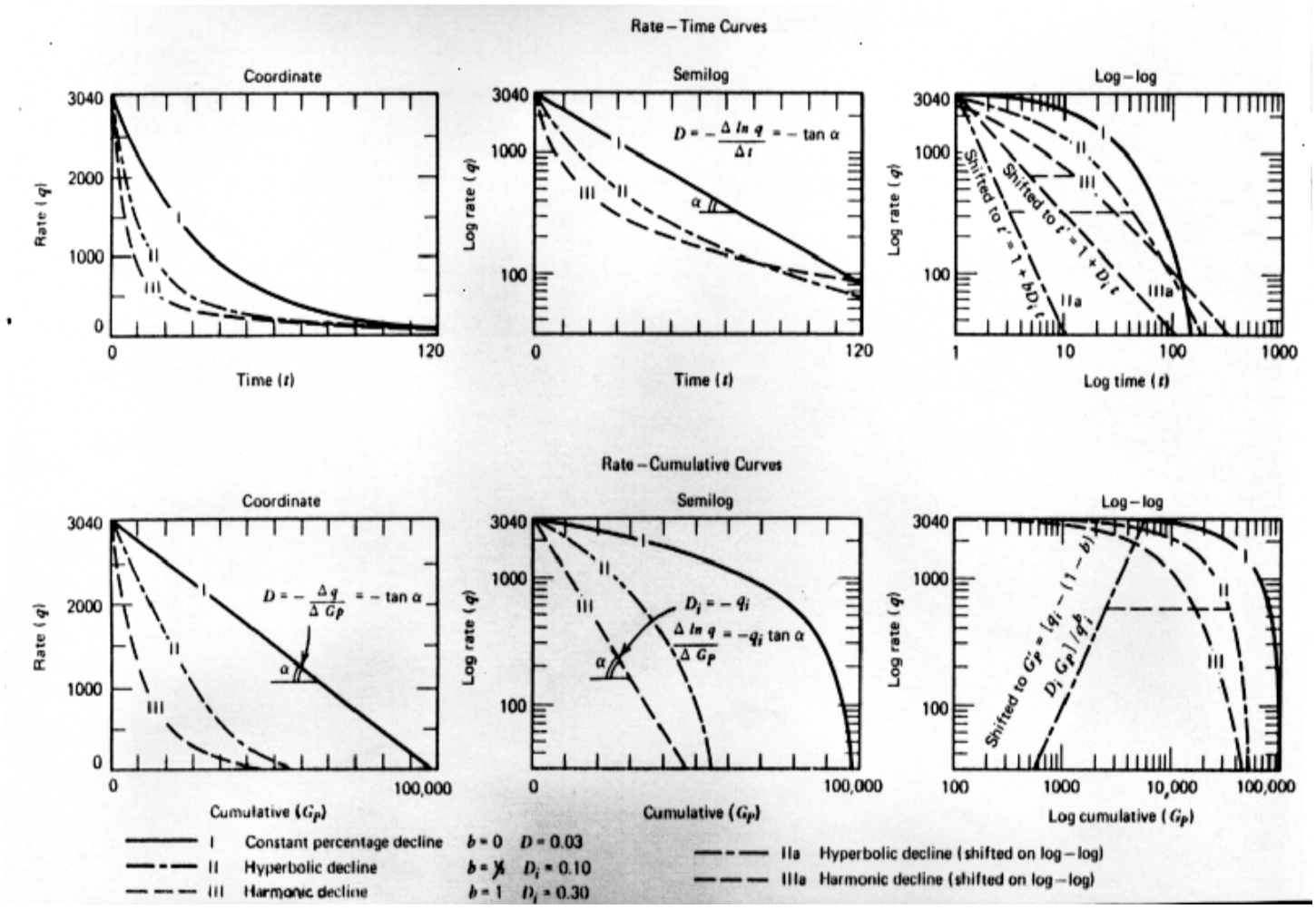


Figure 2.1 Typical Decline shape responses using Cartesian, log-log, and semilog plots for time vs rate, and Gp vs rate.

2.1.1 Exponential Decline

This type of decline is also called constant percentage decline. This decline curve is the simplest one and often used since many wells and fields follow a constant percentage decline over a great portion of their productive life, and only deviate from this behavior at the end of the productive life. The decline rate *D*, is a constant percentage of the initial flow rate. The general form of this decline is illustrated by equation 2.2:

$$q(t) = q_i e^{-Dt} \qquad 2.2$$

This equation is the result of the derivation of the equation 2.1 assuming a depletion stem *b* as zero followed with a limiting process of $b \rightarrow 0$. As is seen in figure 2.1 the response in a plot of logarithm of the gas flow rate versus time is a straight line with a slope $-D/2.303$, and an intercept equal $log(q_i)$. Once this information is obtained, future production can be calculated for any time, substituting the decline rate and the initial flow rate into equation 2.2. Also it is observed that the curve of rate vs. cumulative production for exponential decline is linear on Cartesian plot. If equation 2.2 is integrated from initial time to time *t*, equation 2.3 is obtained:

$$q(t) = -DGp + q_i \qquad (2.3)$$

This equation suggest that this plot will yield a straight line of slope *-D*, and intercept q_i. As a result, an analysis of cumulative production vs. flow rate can be performed from this equation.

2.1.2 Harmonic Decline

When $b = 1$, the decline is defined as harmonic and the general decline equation given by equation 2.1 yields equation 2.3:

$$q(t) = \frac{q_i}{(1 + Dt)} \qquad (2.4)$$

Taking base 10 logarithms of both sides of this equation, equation 2.5 is obtained:

$$\log q(t) = \log(q_i) - \log(1 + Dt) \qquad (2.5)$$

This equation suggests that the flow rate is a linear function of *(1+Dt)* on log - log graph and will show a straight line with a slope of *-1* and intercept of $Log(q_i)$. To predict future gas deliverability, the value of the decline rate should be assumed until fulfill the condition of slope equals to *-1*. To use a rate/cumulative production plot for harmonic decline, equation 2.3 must be integrated with respect to time to obtain a relation, which include this variable. As a result, equation 2.6 is obtained:

$$\log q(t) = Logq_i - \left(\frac{D}{2.303q_i}\right)Gp \qquad (2.6)$$

This equation suggest that the plot of *log q(t)* vs. *Gp(t)* will be linear with a slope of $-(D/2.303\ q_i)$ and an intercept of $log(q_i)$. This equation is a much simpler way to calculate future gas rates, since no trial - error procedure is need to calculate the decline rate[2].

2.1.3 Hyperbolic Decline

Hyperbolic decline curves show values of *b* between *0* and *1*.Thus, if logarithm is taken of both sides of equation 2.1, equation 2.7 is obtained as follows,

$$\log[q(t)] = \log(q_i) - \frac{1}{b}\log(1 + bDt) \qquad (2.7)$$

this equation suggests that if, a log - log plot of *q(t) vs. (1+bDt)* is plotted, a straight line with slope of *1/b* and an intercept of $log(q_i)$ are obtained. In order to analyze gas production at any time, it is previously necessary to estimate values of *D* and *b*, which yield a straight line. Therefore, an iterative process is needed to find these values. A cumulative production/time relationship is obtained by integrating equation 2.1.The result of this integration yields equation 2.8:

$$Gp = \frac{q_i^{\,b}}{D(b-1)}\left[q(t)^{1-b} - q_i^{\,1-b}\right] \qquad (2.8)$$

It has been observed that although the plotting technique gives acceptable results, field rate data generally yield poor derivatives, which makes this method difficult to apply[2].

2.2 Decline Analysis using Type Curves

Unlike Arps empirical decline curve analysis techniques, type curves are long-term constant pressure solutions based on theoretical considerations. The type curves are derived from models that simulate the production - decline behavior of a gas well against a constant back pressure, *Pwf*[1]. Type curves are presented as plots in the form of dimensionless flow rate versus dimensionless time on log - log scale. In order to make a forecast using this technique; the history gas production is matched which type

curves until one is found, which most closely resembles the behavior of the actual data. Once the best possible match is found, the future production rates, gas reserves and reservoir parameters are evaluated from the chosen type curve. This chapter discusses the models presented by Fetkovich[3], Carter[4], Fraim and Wattenbarger[5], but in particular the development and equations utilized by Aminian et al in the gas well production forecast.

2.2.1 Literature review for type curves

Fetkovich introduced the concept of type curve matching. He combined the analytical constant terminal pressure solutions of the well diffusivity equation with the classical decline curve equations to yield a series of composite log - log dimensionless curves[6]. These curves assume a constant flowing pressure from a well centered in a circular reservoir with no flow boundaries. They also can be used for analyzing long - term gas production data from hydraulically fractured wells during the pseudoradial flow period and once the outer boundaries affect the pressure response[1]. Figure 2.2 shows a series of gas well production decline curves developed by Fetkovich. These curves are the result of the combination of the empirical - back pressure equation given by equation 2.9 and the gas material balance assuming the gas compressibility factor, *z* equals to 1.

$$q = C\left(P_R^{\,2} - Pwf^{\,2}\right)^n \qquad (2.9)$$

$$P_R = -\left(\frac{P_i}{G_i}\right)Gp + P_i \qquad (2.10)$$

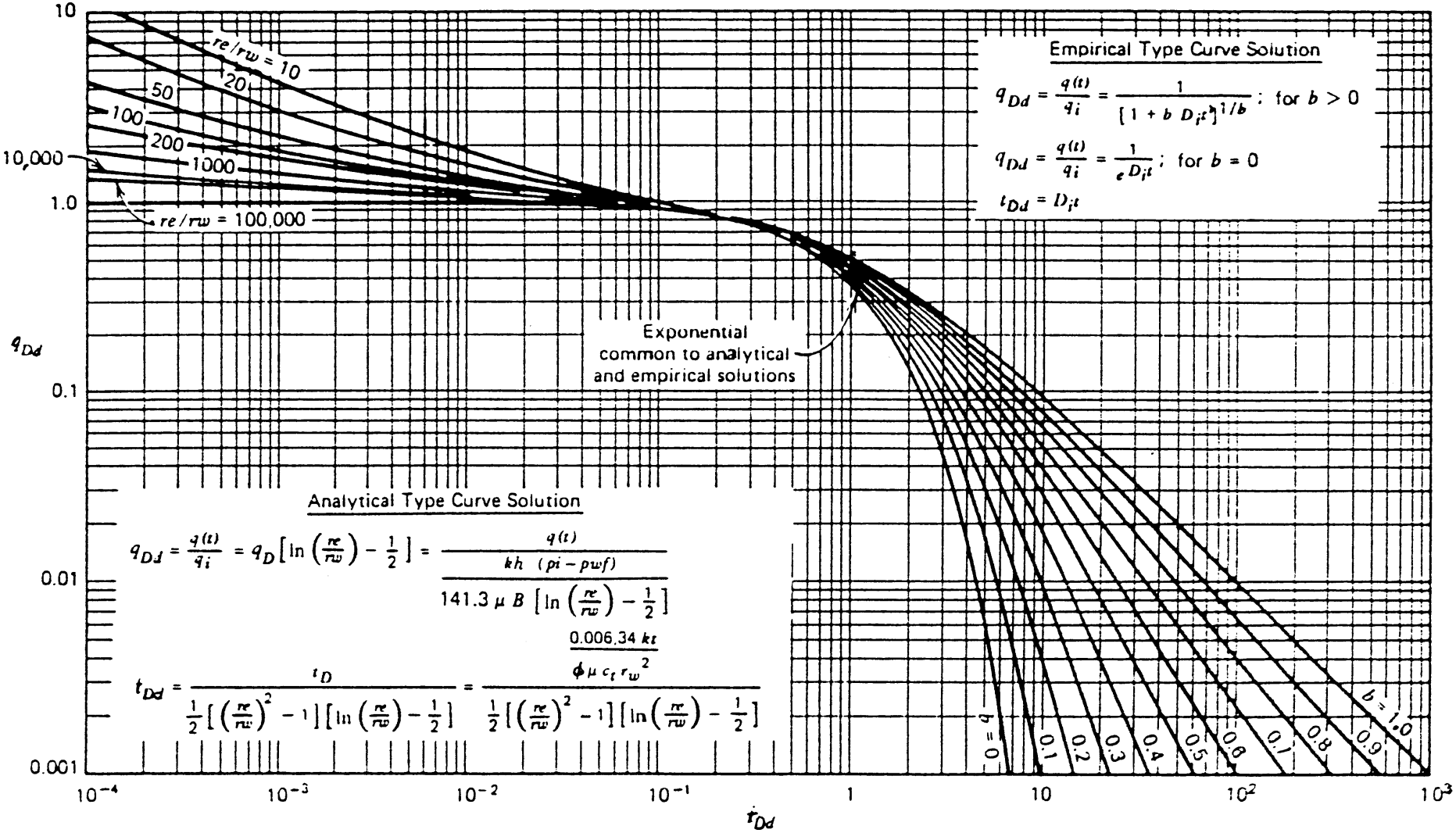


Figure 2.2 Fetkovich rate time decline type curve

These curves are presented as dimensionless flow rate and the dimensionless time for various values of the exponent *n* and the ratio between the original shut in pressure to the constant flowing pressure. Two flow periods are represented. The curves at small values of dimensionless times represent the transient or infinite acting response. All the transient curves converge at a dimensionless time of about *0.3*; showing the approximate beginning of boundary dominated flow. The curves after this value show the boundary dominated flow responses, which were generated with Arps empirical decline equation.

In order to forecast gas production, values from the relation, r_e/r_{wa}, and *b* must be read from the type curve match for both cumulative production/time and gas rate/time. Also a match point for gas rate and time must be selected. From these information values for permeability, rate decline, reservoir pore volume, and skin are obtained. Future values for gas rate and time could be obtained graphically from the chosen type curve or by substituting values for *b*, *D*, and q_i into the general Arp's equation 2.1.

It should be noted that these type curves are developed using the theoretical constant pressure solution for single - phase liquid systems and the empirical decline curves. Consequently, they assume that the liquid viscosity - compressibility product is constant over the entire productive life of a well. Although this assumption is correct for modeling liquid flow during both transient and boundary dominated flow

regimes, they neglect the pressure loss due to high velocity gas flow as well as the pressure dependency of the gas compressibility and gas viscosity.

Later, Carter[4] generated a set of curves with a finite-difference reservoir model. These types curve improved the accuracy of the analysis by plotting functions that include the changes in gas properties with pressure. Thus, he considered the changes of the product $u_g\ C_g$ with the average reservoir pressure using a drawdown parameter λ as show in equation 2.11,

$$\lambda = \frac{\mu(P_i)C_g(P_i)}{2}\frac{\left[P_p(P_i) - P_p(Pwf)\right]}{\left[(P/z)_i - (P/z)_{wf}\right]} \qquad (2.11)$$

Where this parameter varies between 0.5 to 1,defining λ=1 for liquid flow, and λ=0.5 for maximum gas - reservoir drawdown. Also Fraim and Wattenbarger showed that gas well production rates decline exponentially against the normalized time[7] as defined in equation 2.12[7]:

$$t = \int_0^t \frac{\mu_{gi}C_{gi}}{\mu_g C_g}dt \qquad (2.12)$$

However, all these authors have neglected the inclusion of non-Darcy flow in their calculations. A set of more representative curves were developed by Schmid[8] et al and Aminian[2] et al by combining the theoretical stabilized gas flow equation, equation 2.13 and the material balance for a gas reservoir, equation 2.14.

$$P_P(P) - P_P(Pwf) = aq + bq^2 \qquad (2.13)$$

$$Gp = \left[\frac{P_1 / z_1 - P_2 / z_2}{P_1 / z_1} \right] G_1 \qquad (2.14)$$

The model accounts for non-Darcy flow and dependency of gas properties on pressure.

The models previously discussed assume constant reservoir parameters and operating conditions during the entire life of the reservoir. Aminian[1] et al (1990) have discussed the violation of this assumption in practice due to changes in well spacing owing to infill drilling, back pressure changes due to compressor installation, and changes in skin factor due well stimulation. Thus, Aminian et al have accounted for these modifications in their equations developing relations between the type curve parameters and the producing formation characteristics. These correlations are used in conjunction with the type curves to predict the production rates when reservoir parameters are not constant[9].

2.2.2 Aminian[1] et al Type Curves

The theoretical model developed to generate the type curve model follows the next assumptions in the developing of the equations:

- Closed-gas expansion with non-water drive gas reservoir
- Pseudosteady state flow regime[10]
- Constant well flowing pressure
- Homogeneous and isotropic formation
- High gas flow rates into wells

Equation 2.15 shows the analytical solution developed by Aminian et al:

$$\ln q_D + 2(1 - F_{NDi})(q_D - 1) + \frac{F_{NDi} F_{taD}}{[1 - (1/X_i)]L} t_D = 0 \qquad (2.15)$$

All these variables are defined in table 2.1as follows,

Table 2.1 Terms included in the constant pressure solution developed by Aminian et al.

Parameter	***Equation***
Dimensionless Flow Rate	$q_D = \frac{q}{q_i}$ *(2.16)*
Non-Darcy Flow Ratio	$F_{NDi} = 1 + \frac{bq_i}{a}$ *(2.17)*
Darcy Flow Coefficient, $psi^2/(cp)(Mcf/D)$	$a = \frac{1422T}{Kh\left[0.5\ln\left(\frac{10.06Area}{CArw^2}\right) - 0.75 + s\right]}$ *(2.18)*
Non Darcy Flow coefficient, $psi^2/(cp)(Mcf/D)^2$	$b = \frac{3.161E-12\beta T\gamma}{h^2\overline{\mu}\left[\frac{1}{rw} - \frac{1}{re}\right]}$ *(2.19)*
Turbulence Coefficient ft^{-1}	$\beta = \frac{2.73E+10}{K^{1.1045}}$ *(2.20)*
Pseudotime ratio	$F_{taD} = \frac{\int_0^t \frac{dt}{\mu_g C_g}}{\frac{t}{\mu_{gi} C_{gi}}}$ *(2.21)*
Pseudopressure, psi^2/cp	$P_P(P) = \int_0^P \frac{2PdP}{\mu_g z}$ *(2.22)*

Dimensionless time	$t_D = \frac{q_i t}{G_i}$	*(2.23)*
Drawdown parameter	$L = \frac{\left[P_p(P) - P_p(Pwf)\right]\left(\mu_{gi} C_{gi}\right)}{2\frac{\left(\frac{P}{z}\right)_i}{\left(\frac{P}{z}\right)_{wf}}}$	*(2.24)*
Dimensionless parameter X_i	$X_i = \frac{\left(\frac{P}{z}\right)_i}{\left(\frac{P}{z}\right)_{wf}}$	*(2.25)*

The Pressure dependency of the gas properties is represented by $F_{taD,}$ which contains the pseudotime, and L, which contains pseudopressure. Pseudopressure as defined by equation 2.22 takes into account the variation of gas viscosity and gas compressibility factor with pressure. The evaluation of the expression requires numerical integration since no mathematical expression for z, ug, and Cg as function of pressure exist[11]. Thus, pseudopressure can be approximated to a linear function using the trapezoidal rule[11] as equation 2.26 shows:

$$P_p = \sum_{i-1}^{n}\left[\left(\frac{P}{\mu z}\right)_i + \left(\frac{P}{uz}\right)_{i-1}\right]\left(P_i - P_{i-1}\right) \qquad (2.26)$$

The effect of non-Darcy flow is quantified by $F_{NDi.}$ Aminian et al, concluded that the dependency of type curves on permeability, initial pressure and skin factor are caused by variations of this parameter.

In order to generate a type curve from equation 2.15, it is necessary to determine F_{taD} for each point of the decline curve, which means for each pressure. Two approaches have been proposed to solve this expression. Abidi[12] introduced the first approach known as direct method in 1991. This method solves the equation directly by utilizing polynomial approximations for F_{taD} as function of t_D.

The effect of various parameters such as *Pi*, *Xi*, and *K* on F_{taD} was studied by plotting F_{taD} vs. t_D on log- log paper. Sets of $F_{taD} t_D / \lambda(1-1/X_i)$, and $t_D/(1-1/Xi)$ were developed in order to establish a correlation between F_{taD}, and t_D. In order to generate a type curve from these plots a polynomial regression method was used. This technique employs a least squares fit of the data by successive polynomials of order *n = 1 to 4*, and examines the standard deviation *S* about the regression line in each case. Thus, the type curves generated by using these correlations were compared to the type curve generated by numerical methods finding an alternative method to model Aminian et al Type curves.

The second approach is the indirect method, which utilizes a stepwise method of solving material balance and deliverability equations simultaneously to determine rate versus time and converts the results to dimensionless rate and time[1]. This method is the foundation of the computer program for generating type curves. The methodology used for this purpose is explained in chapter 3.

It has been observed that if both the non-Darcy and pressure dependency of the gas properties is ignored, $F_{taD=}1$, $L=1.0$, and $F_{NDi,}$ then the equation reduces to the familiar exponential decline. This is true for single-phase liquid flow. If only the non-Darcy flow is ignored $F_{NDi=}1$, then the equation reduces to exponential decline against normalized time as suggested by Fraim and Wattenbarger. Therefore, the equation is the most general and accurate form of the constant pressure pseudo-steady-state solution for single-phase gas flow[9].

According to the number of known variables available to generate type curves, different scenarios can be analyzed. If only one of the limiting values of pressure is known, multiple sets of type curves are generated for specific values of F_{NDi} by varying X_i. Figure 2.3 shows different type curves generated by varying the values of the dimensionless parameter *Xi*, as defined in equation 2.28, for an initial pressure of 2000 psia and $F_{NDi=}2$. As is observed, X_i parameter defines the pressure drawdown exhibited by the well. As the pressure drawdown is larger the curves shift to the right due to the larger gas production at higher differential pressure.

If the limiting values of the pressure *Pi*, and *Pwf* are known then *L*, and *Xi* can be easily determined by substituting pressure values between this interval in their respective equations. Figure 2.4 depicts a set of type curves for *Pi*=2000 psia, and *Pwf* =100. As is observed, the effect of larger $Fndi_{(s)}$ results in a shift of the curves to the

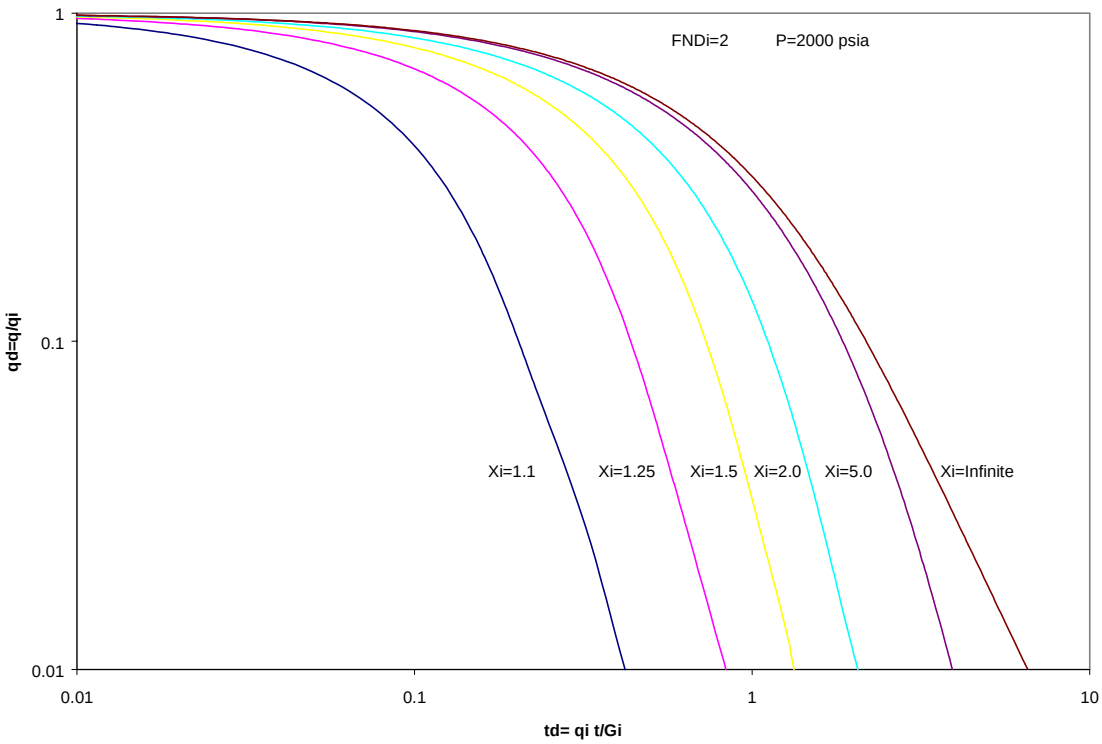


Figure 2.3 Constant back-pressure gas well production decline curves

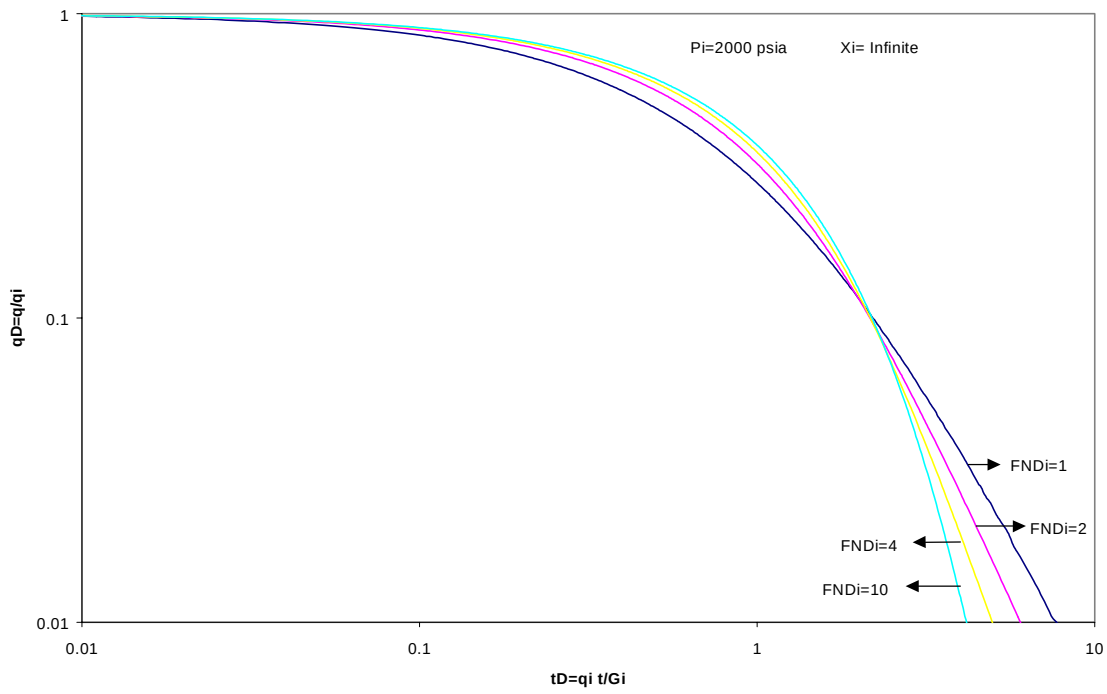


Figure 2.4 Effect of non-Darcy flow on type curves

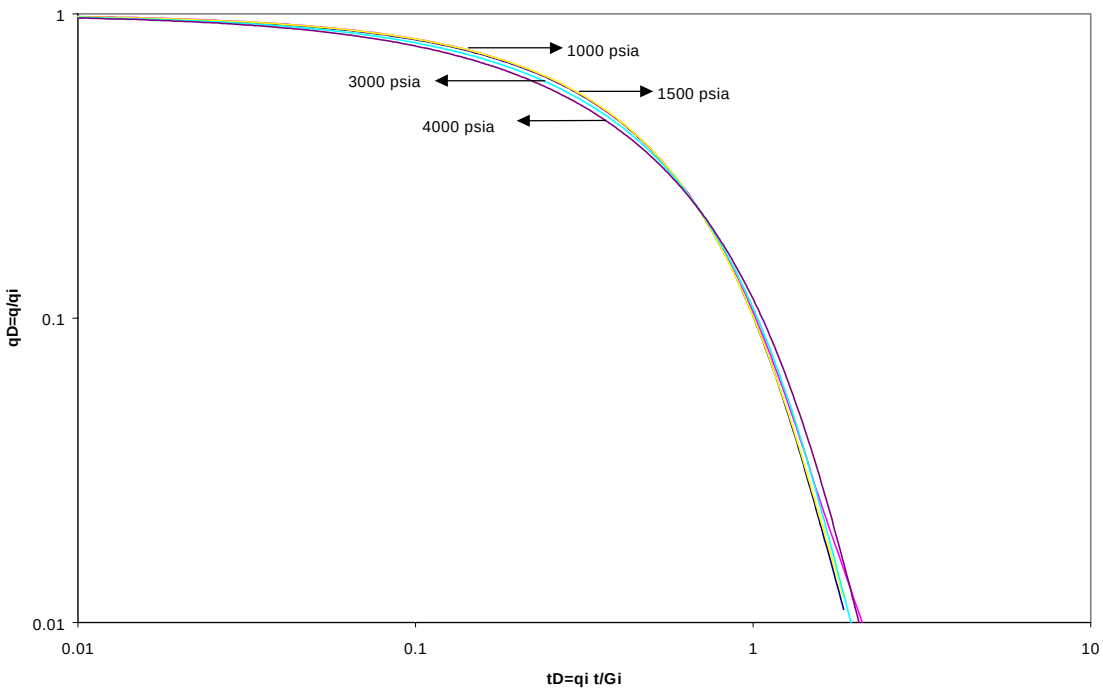


Figure 2.5 Effect of Pi on type curves

left side due to shorter gas production and production time. It is also observed that values of F_{NDi}, larger than 10 do not result in significant variations in the shape of the type curve.

Figure 2.5 illustrates type curves with X_i=1.815 and F_{NDi}=1.76 generated for various values of initial pressure *Pi*. These sets can be obtained either by adjusting reservoir permeability or skin factor to keep constant the F_{NDi} values. As the figure shows, the initial pressure influences the type curve only slightly when the non-Darcy effects are kept constant[7]. These changes are the result of variations in *FtaD* and *L* given by equations 2.21 and 2.24.

Also sets of cumulative production type curve were generated as shown in figure 2.6, where the dimensionless cumulative production G_D is defined as of the gas cumulative production divided by the initial gas in place as follows,

$$G_D = \frac{G_p}{G_i} \qquad (2.27)$$

Aminian et al performed many simulation runs to study the effect of various reservoir parameters on the shape of the type curves. As a result, the formation permeability, the skin factor and the shape factor were found to have some effect on the curves. The effect of permeability was found to be relatively small and it is recommended that for different ranges of permeability, the type curves are generated separately[9]. The effect of skin factor is shown in figure 2.7 with insignificant effects at small dimensionless time values. At larger dimensionless time values skin factor

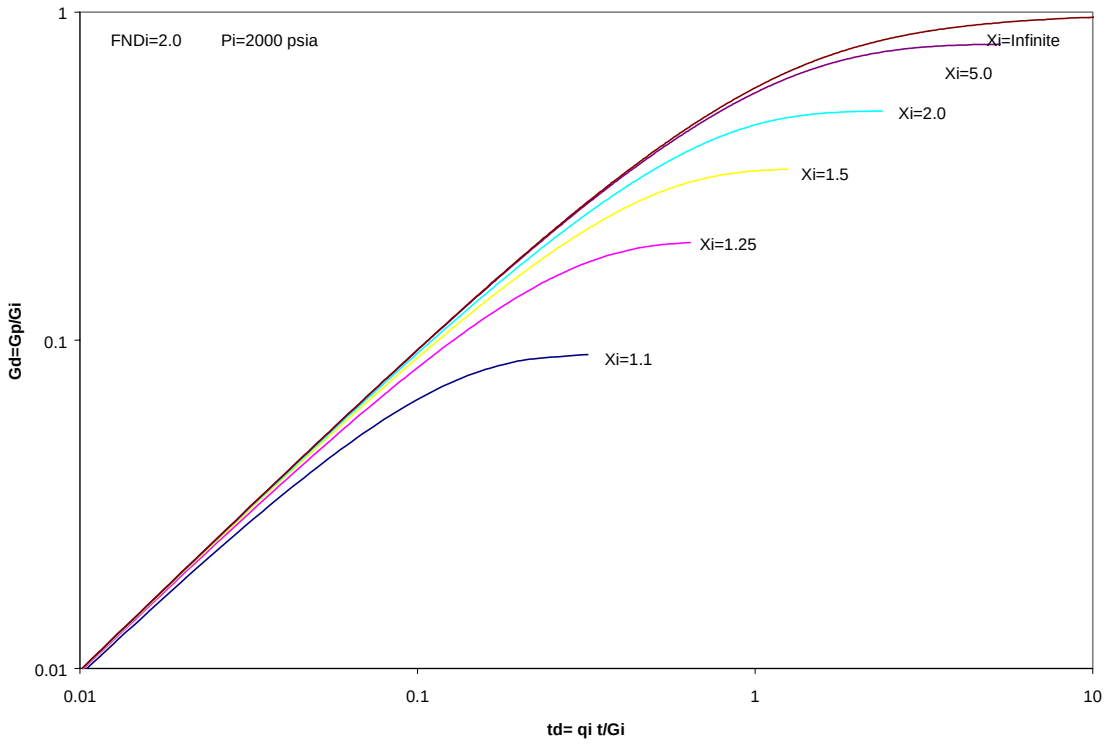


Figure 2.6 Cumulative-production type curve for dry gas wells producing against constant back-pressure.

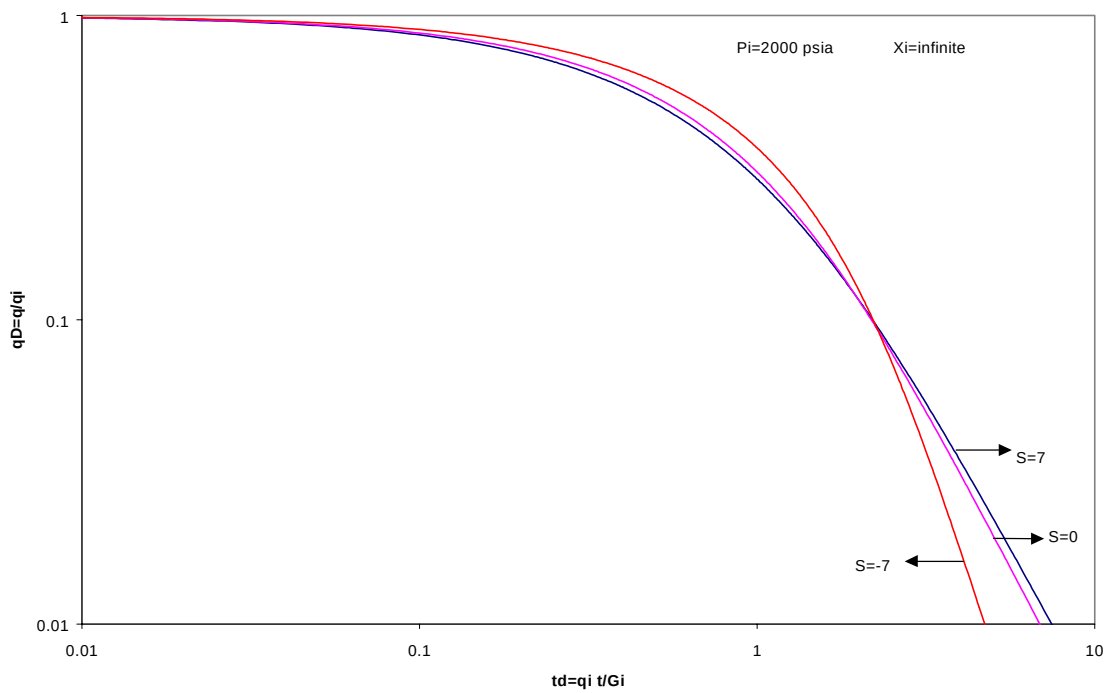


Figure 2.7 Effect of skin factor on the shape of the type curves

makes significant change between curves. These changes are the result of Non-Darcy effects, $F_{NDi.}$ Therefore, they are accounted for in the type curves. The effect of the shape factor was also found very similar to that of skin factor[9].

2.2.2.1 Type Curve Utilization

To analyze the past production data, a log-log plot of actual production rate versus time is overlaid on different sets of type curve. The closest type curve to the production history is chosen as the match for it. As a result of these match the value of *Xi*, *Pi*, and F_{NDi} are directly obtained from the type curve. As is seen in Figure 2.8, the matched type curve differs from the plot of actual data only by a shift in coordinates. Hence, an arbitrary match point should be selected, and the two sets of coordinates are used to evaluate q_i and *Gi* as defined by equation 2.28 and 2.29.

$$q_i = \left(\frac{q}{q_D}\right)_{match} \qquad (2.28)$$

$$G_i = q\left(\frac{t}{t_D}\right)_{match} \qquad (2.29)$$

As *Pi* and X_i are read from the matched type curve, the value of *Pwf* is obtained from X_i relation. Knowing *Pwf*, the values of non-Darcy coefficient *b*, and Darcy coefficient *a* of the quadratic gas flow equation defined by equation 2.13 are obtained by equations 2.30 and 2.31.

$$a = \frac{\left[P_p(P_i) - P_p(Pwf)\right]}{q_i F_{NDi}} \qquad (2.30)$$

$$b = \frac{(F_{NDi} - 1)a}{q_i} \tag{2.31}$$

Thus, with this information gas deliverability can be calculated by substituting either *Pwf* or *q* into the quadratic equation. Gas reserves and times of production are obtained by using the material balance equation.

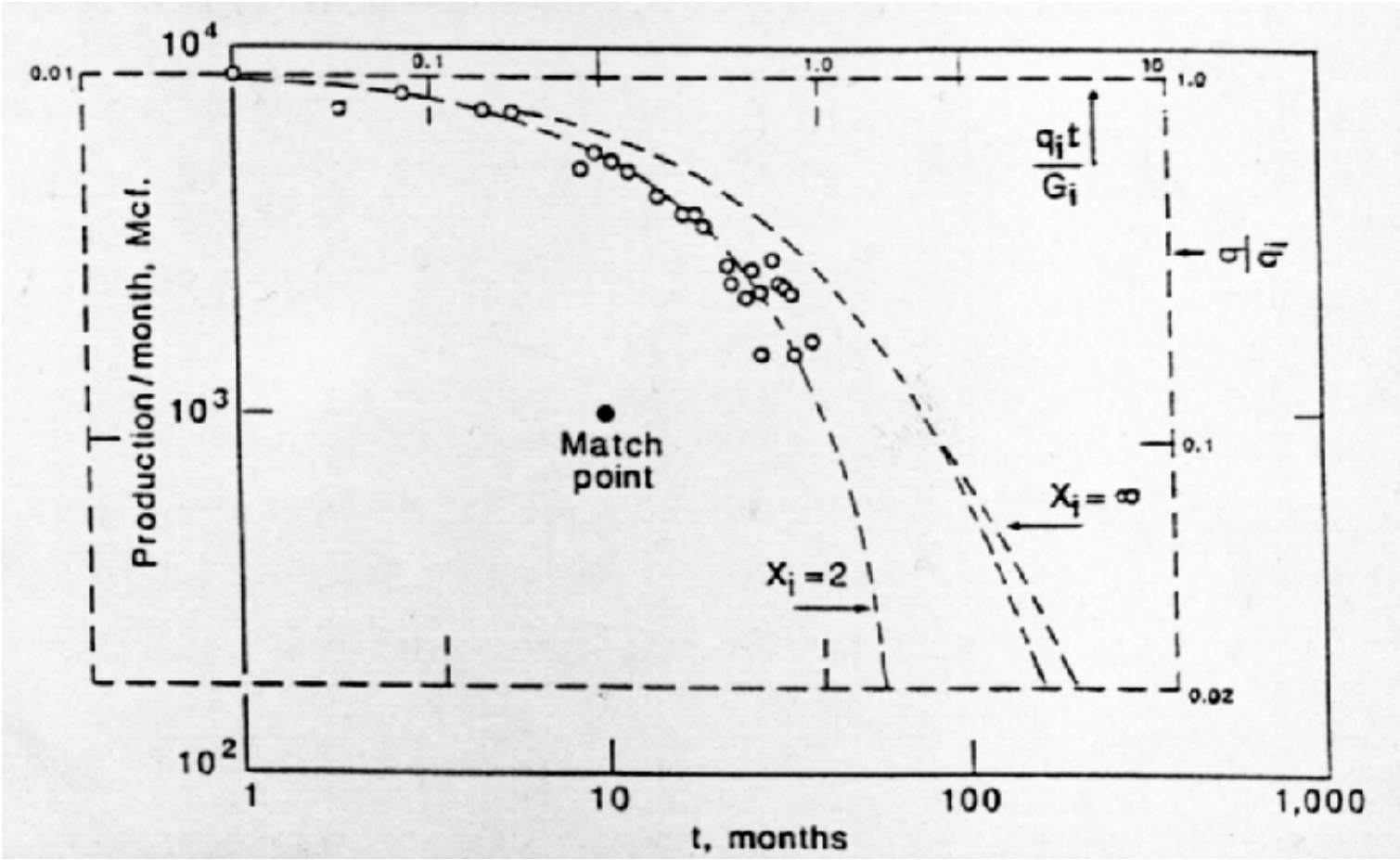


Figure 2.8 Graphic example of the type curve matching

CHAPTER 3

METHODOLOGY

This chapter discusses the procedure followed by the computer program in order to perform automatic type curve matching. The computer program consists of three general steps to achieve this objective. The first step is the generation of type curves where the number of the generated type curves changes whether high or low permeability reservoirs are being analyzed. The second step is an interpolation process to find the corresponding flow rates on the type curve for the history production. The last step is a comparison process using least square method to find the best possible match.

3.1 Type Curve Generation

In order to generate a single type curve gas properties must be defined at every point of the proposed gas declines. As it was mentioned in chapter 2, X_i, F_{NDi}, and initial gas in place G_i are required to generate an individual type curve. As this information is not available to initiate type curve matching, the program iterates on these three parameters by proposing a range of permeability, flowing pressure and initial gas in place to initiate the search. It is assumed that usual information as initial pressure, gas gravity, and reservoir temperature is known. Thus, varying *Pwf* covers the range of iteration on X_i. Varying permeability covers the range of iteration on F_{NDi},

and the variation on in *Gi* is covered as its expression is modified. Gas properties such as gas deviation factor, gas compressibility, gas viscosity and pseudopressure are computed for every pressure between the initial reservoir pressure *Pi* and *Pwf*. The next step in the type curve generation is the calculation of the coefficients of the quadratic deliverability equation *a* and *b*. As is seen in equations 2.18 and 2.19, these expressions include reservoir parameters such as reservoir area, shape factor, reservoir thickness and skin factor. These parameters must be entered to execute the type curve calculation and can be assumed as long as an iteration on F_{NDi} is performed. These parameters do not have direct influence on the final match since the iteration on F_{NDi} is done by varying the value of permeability, and F_{NDi} will be the variable that defines type curve matching as well as *Pwf* and *Gi*.

A pressure step of five psia was considered to generate type curves, since it offers great accuracy in the process of interpolation and curve comparison. Once *a*, and *b* coefficients are identified, gas flow rate is obtained by solving the quadratic gas flow equation given by equation 2.13 as show in equation 3.1.

$$q = \frac{-a + \sqrt{a^2 + 4a\left(P_p\left(P_i\right) - P_p\left(P_{wf}\right)\right)}}{2b} \qquad (3.1)$$

The initial gas flow rate q_i is obtained by substituting the conditions at initial pressure into equation 3.1. At this point F_{NDi} and X_i are defined by equations 2.17 and 2.25. As also mentioned before, in order to generate any type curve, F_{taD} needs to be determined for point of the curve. This is achieved by utilizing a stepwise method of

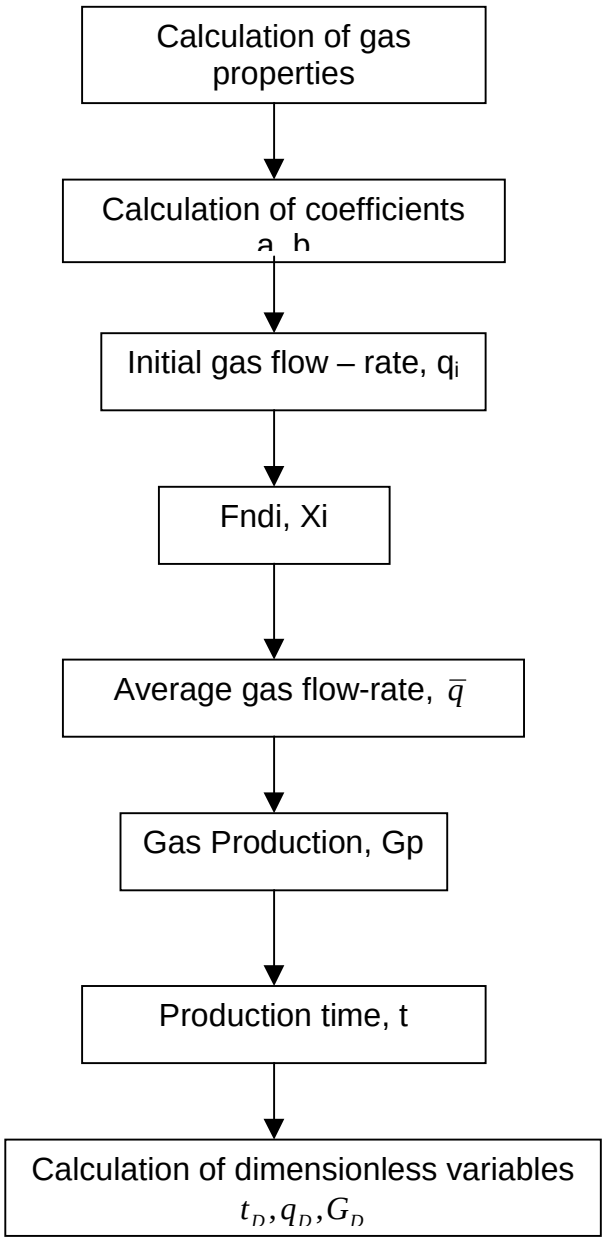


Figure 3.1 Procedure to generate Aminian et al Type Curves

solving material balance and deliverability equations simultaneously to determine rate versus time and converts the results to dimensionless rate and time. Thus, for every step of time and average rate $\bar{q}$ is calculated with respect to the initial flow rate. Time of gas production is calculated as shown in equation 3.2 dividing the amount of gas produced *Gp* given by the material balance equation into the average gas flow rate $\bar{q}$.

$$t = \frac{G_i}{\bar{q}}\left(\frac{B_{gf} - B_{gi}}{B_{gf}}\right)$$

(*3.2)*

After time and gas flow rates are obtained, dimensionless variables t_D, q_D, and G_D, are calculated by equations 2.23, 2.16, and 2.27. Figure 3.1 illustrates the procedure to generate Aminian et al type curves.

3.2 Approach to the Matched Curve

As it was mentioned in section 3.1, the program varies *K*, *Pwf*, and *Gi* to find the best possible type curve for the production history. Basically, the type curve matching is achieved using two stages of search. During the first stage, three ranges are defined for the search. For permeability the first range of search is defined between 1 md to 100 md, for *Pwf* between 100 psia to 1100 psia, and for *Gi* between 0.1 Bcf to 20 Bcf. Each of these ranges is divided in 50 steps. Thus, the first value of permeability is combined with the first value of *Pwf*, and the first value of *Gi* to generate the first type curve for comparison with the available production history. The process is repeated combined all the proposed permeabilities with all the proposed values of flowing

pressure and initial gas in place. As a result 125,000 type curves are generated during the first stage of search. The best combination of these three parameters defined by the least average square difference will be the reference to iterate on in the second stage of search. A mechanism of checking was set to compare every generated type curve. In order to be candidate for comparison the initial flow rate and time of the type curve must be in a range not higher or lesser than 6 percent of the initial flow rate and time of the production history. Consequently, if these conditions are not fulfilled the type curve is discarded from analysis. The second and final search generates ranges between 10 percent of each of the values selected as the best combination from the first stage. These final ranges are divided in 30 steps, which also combine each other to generate another 27,000 type curves. As a result the best combination of this stage yields the closest match for production history. Figure 3.2 depicts the procedure followed to match history productions.

3.3 Method of Comparison

Once a type curve is generated, the available production history is interpolated on the production decline curve obtained from the assumed values for F_{NDi}, X_i, *and Gi*. Thus, each production time of the production history is interpolated among its two most closed values on the decline curve to find its respective gas flow rate. Equation 3.3 shows the linear interpolation relation used in this process.

$$q_{typeCurve} = \frac{(t_{Production} - t_1)(q_2 - q_1)}{(t_2 - t_1)} + q_1 \qquad (3.3)$$

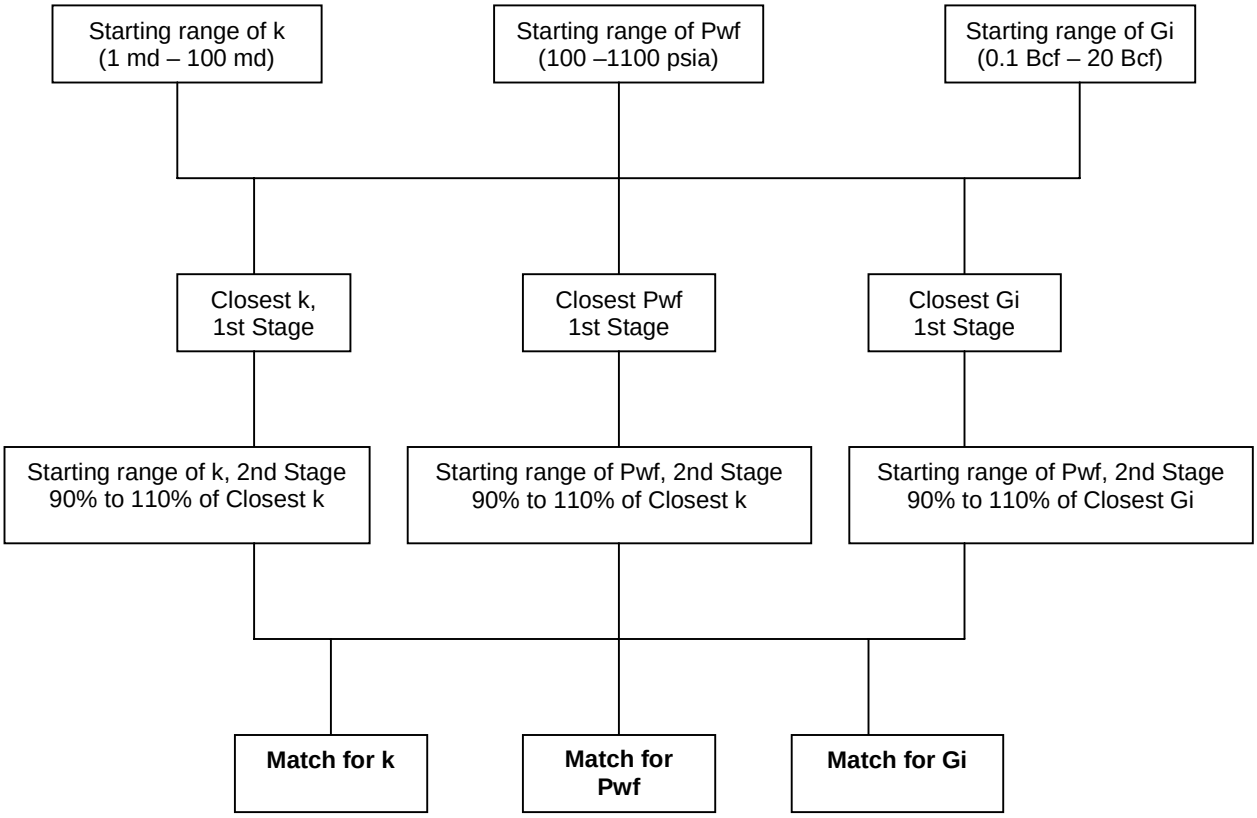


Figure 3.2 Approach to find type curve match

Where t_1 is the time production immediately less than the production time on the type curve, t_2 is the time immediately larger than the production time on the type curve, q_i is the flow rate at t_1, and q_2 is the flow rate at t_2. Once the interpolation is done for all the times of the production history, flow rates from type curve and history production are compare using the method of least squares shown by equation 3.4.

$$ALSD = \frac{\sum_{i=1}^{n}\left(\frac{q_{production_i} - q_{typecurve_i}}{q_{production_i}}\right)^2}{n} \qquad (3.4)$$

Where *ALSD* is the average least square difference, and *n* is the number of time points of the production history. As a result, the closer is *ALSD* to 0, the more accurate is the type curve being compare to the production history. Values of *ALSD* close to 1 or higher that it will result in erroneous matches. Figure 3.3 shows a squematic of the comparison process.

3.4 Low Permeability Cases

For the analysis of wells with reservoir permeabilities less than 5 md a denser search was designed. Generally the first stage of iterations is not enough to find parameters of search for *K, Pwf*, and *Gi*. Thus, if an initial match is not found in the first proposed stage, that is a sign that a low permeability reservoir is being analyzed. As a result, denser range of 270,000 curves is proposed by analyzing a range of permeability between 0.35 to 10 md in 45 steps, for *Pwf* between 100 psia to 1100 psia in 60 steps, and for *Gi* between 0.1 Bcf to 10 Bcf in 100 steps. Likewise, a second stage will be yielded based on ranges of 10% of every parameter to analyze another

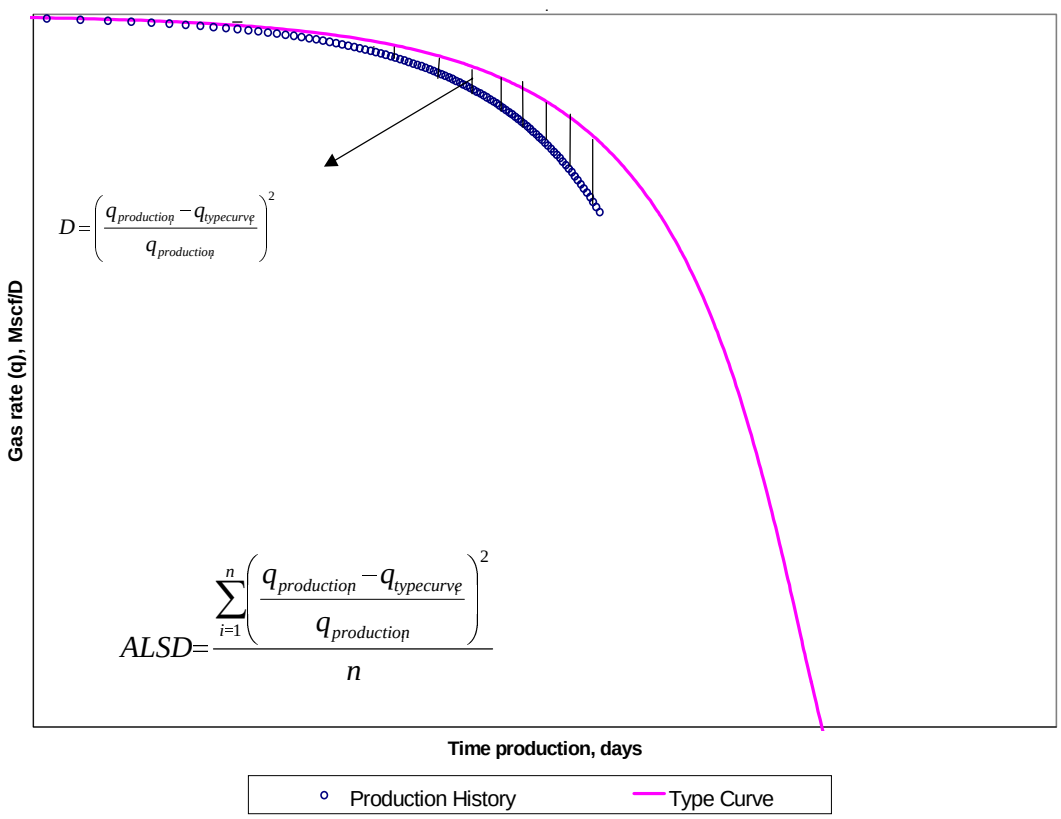
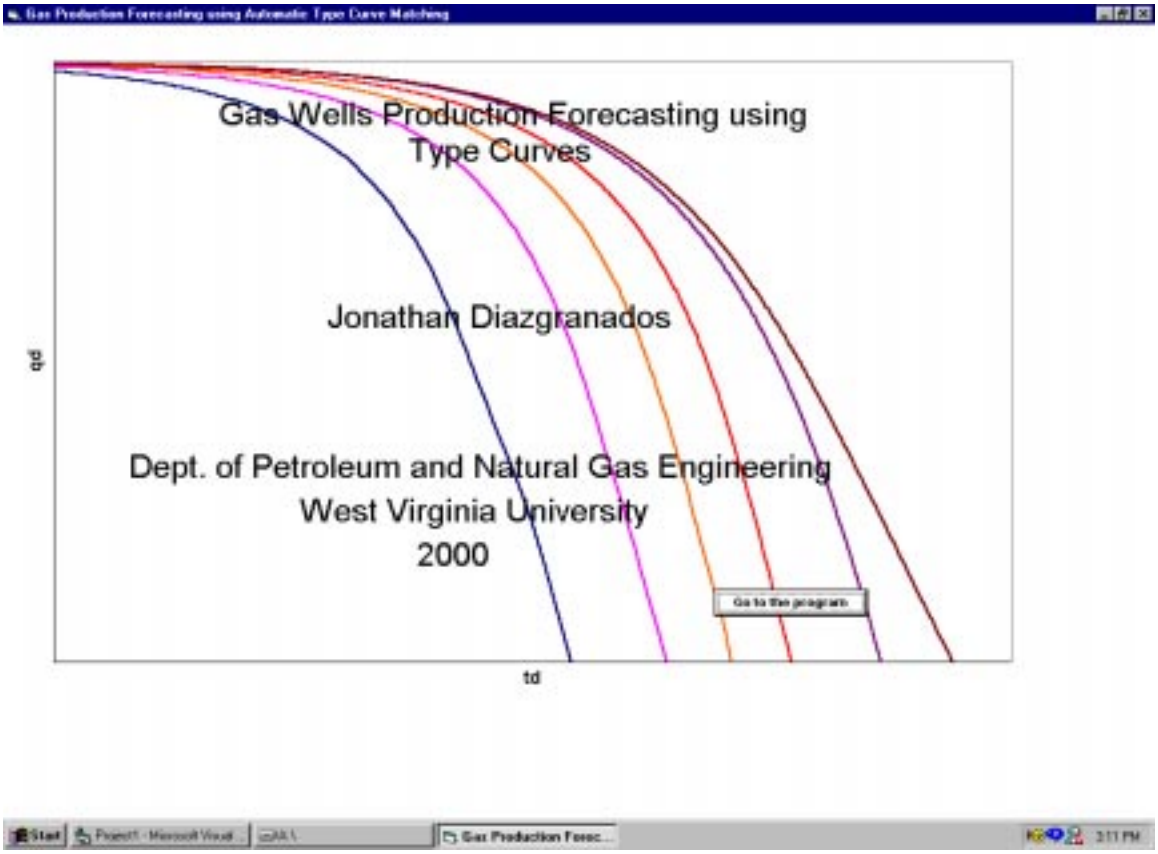


Figure 3.3. Comparison process between Production History and Type Curves.

27,000 type curves. As a result an extensive search of 422,000 curves is designed to find the closest type curve for low permeability reservoirs. Figure 3.3 depicts the procedure followed to match history productions.

3. 5 Computer Program

As mentioned before, the computer program to perform automatic type curve matching was developed in Visual basic 6.0 SP 3 programming language. In order to obtain the matched type curve three user-interfaces were developed as shown in figures 3.4, 3.5 and 3.6. Figure 3.3 shows the initial window of the program, which allows the user to access the three main windows. Figure 3.4 shows the first interface to set production history and gas characteristics. The interface allows the introduction of the production history by clicking the command button for this function. The data contained in the production history must be previously stored in a file with a *txt* extension in order to be read by the program. It is advisable to disregard the first point of the production in the *txt* file to get more accurate results. However, the coordinates of this first point are requested to be entered as initial time and initial flow-rate at the bottom of the attached table. Also, the program requests a specified number of data. The specific number will be the same as the number of data read by the program if the user is analyzing the complete production history. If the total productive life is stored in the file and a determined percentage of it is analyzed a specified number of data must be defined.



3.4 Presentation window of the computer program

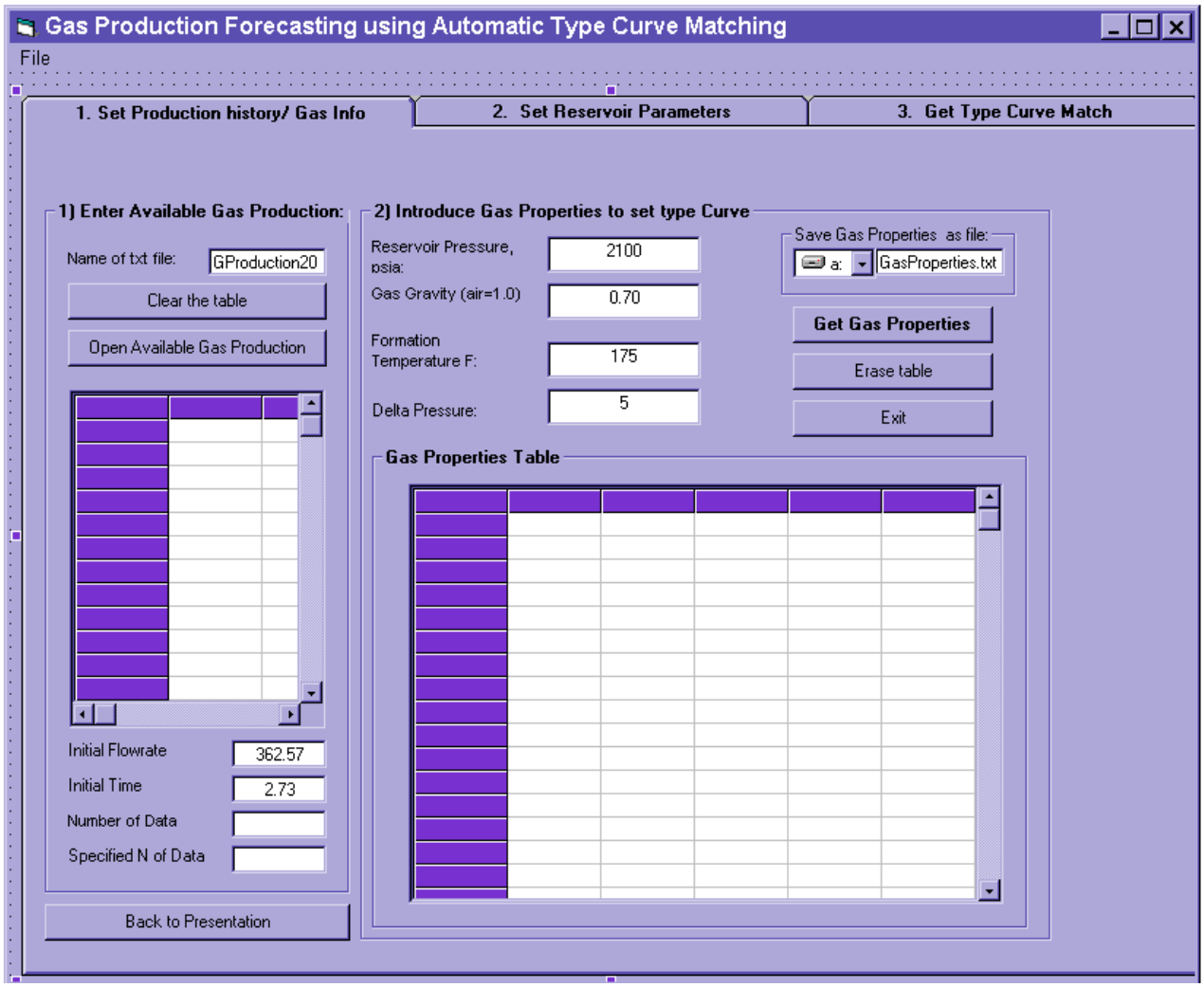


Figure 3.5 Interface for production history entry and gas data settings

A second frame in this interface allows the user to introduce values of initial pressure, gas gravity, formation temperature and the step of pressure to generate the type curve. By clicking on the command button “ Get Gas Properties” the program will show these results in the attached table. The program also allows obtaining a file of the properties by selecting the desired drive to look for the default file Gas Properties.txt. Once the properties values for the production history have been generated the second step is to set up the reservoir parameters. Thus, the second tab should be clicked to get the second interface as shown in figure 3.5. In this interface two options are given to the user. The first one is the generation of a single type curve if all the needed reservoir parameters to generate one are available. By choosing this option, entering the reservoir parameters and clicking the command button “ Get type curve”; dimensionless values for the type are obtained in the attached table. As in interface one, these results can be stored in the file TypeCurve.txt. The second option of the interface allows entering values of skin factor, reservoir area, shape factor, formation thickness, and wellbore diameter to initiate type curve matching for the available production history. The third option allows the user to change one of the previous options if a mistake has occurred in its selection. Once this procedure is finished, the third and last tab should be clicked to get the type curve-matching interface. In this interface the user is allowed to enter the desired ranges of search for permeability, flowing pressure and initial gas in place. Also, a scale to see the final match should be selected before the iteration process starts. Since 125,000 type curve are being analyzed during the first stage of search, this process will take

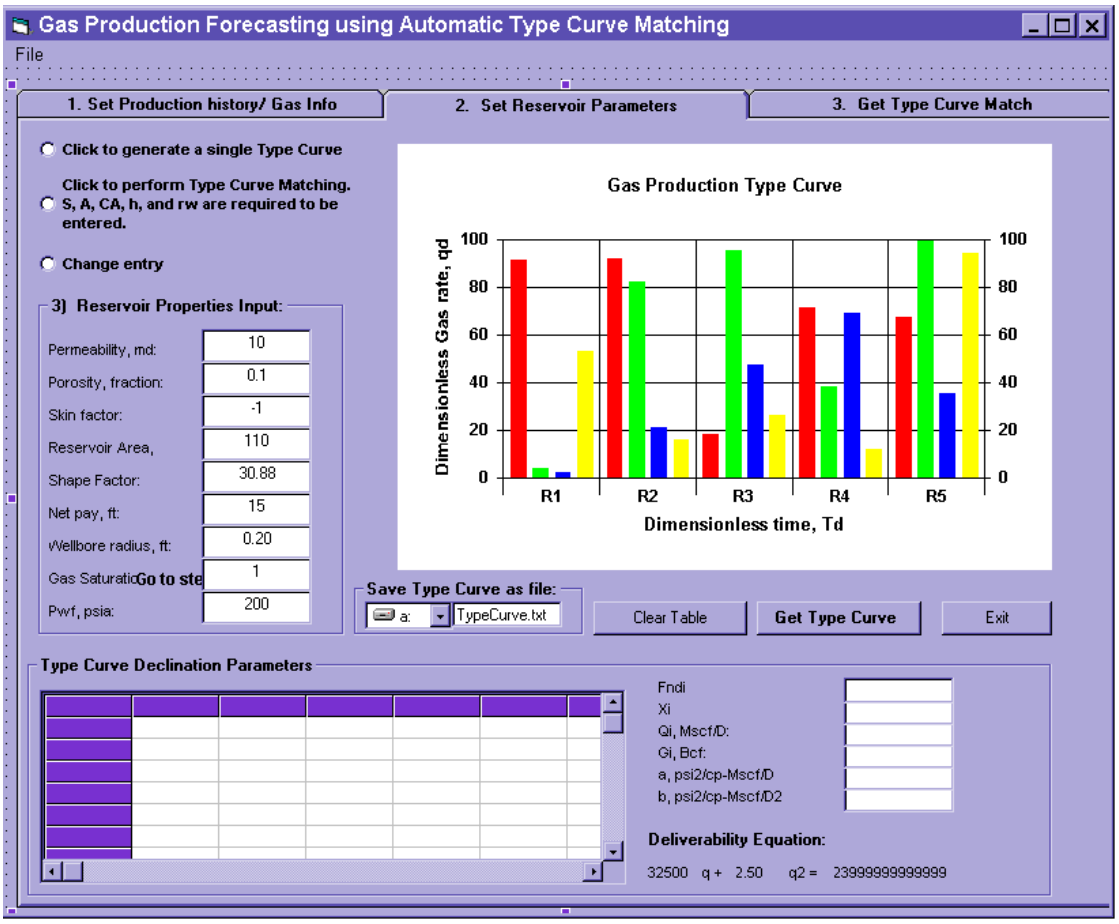


Figure 3.6 Interface for type curve generation and reservoir parameters set up

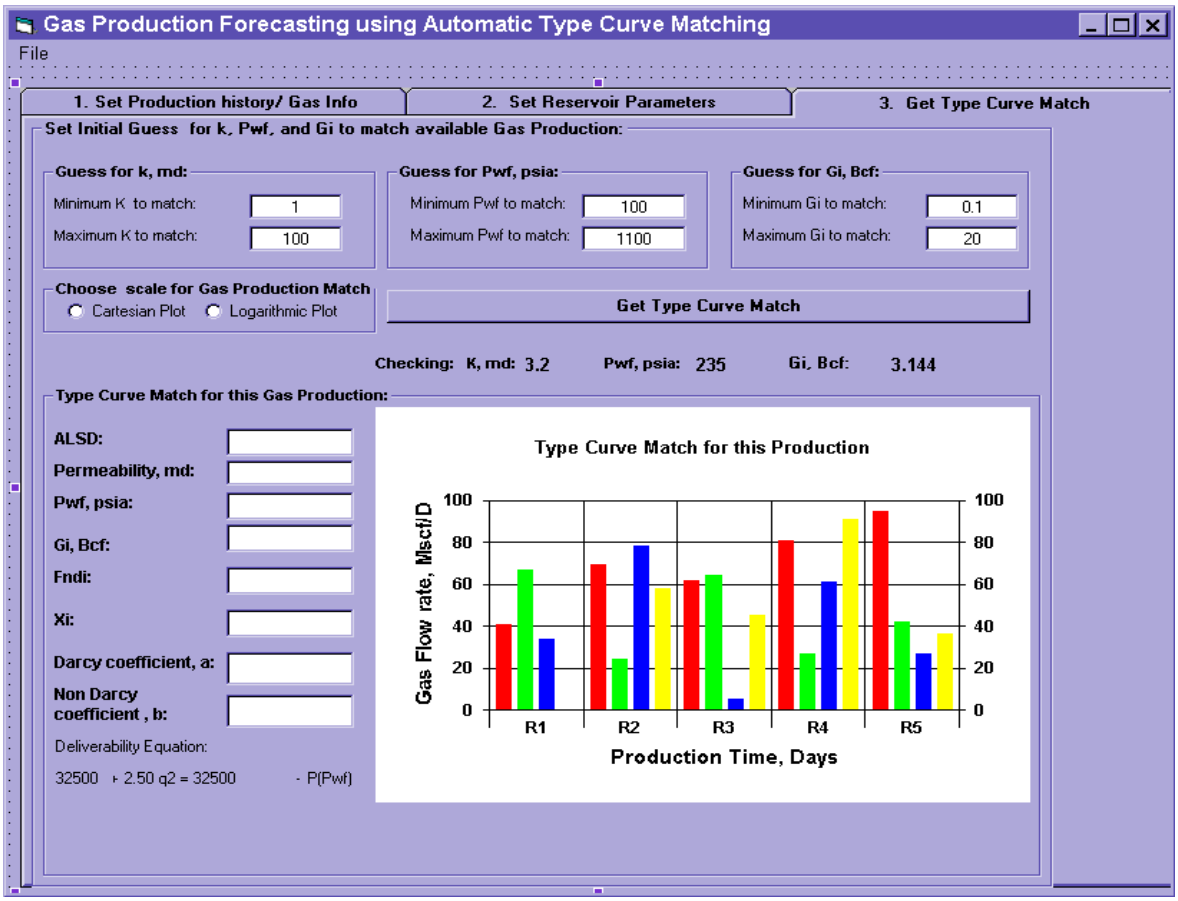


Figure 3.7 Interface to get type curve match

approximately six minutes to yield the reference parameters to iterate in the second stage. During this process the program will show the current values of *K*, *Pwf*, and *Gi* being analyzed. Finally, the program will yield a graphic type curve match with the single results for average least square difference, *K*, *Pwf*, *Gi*, *Fndi*, *Xi*, Darcy coefficient *a*, non-Darcy coefficient *b*, and the general deliverability equation for this match.

3.6 Methodology

In order to verify the accuracy and consistency of the predictions, complete production histories were initially generated to be compared with their predictions. Thus, four different scenarios were considered to evaluate the accuracy of the predictions for gas reservoirs with ranges of permeability from 1 md to 100 md, and for tight gas reservoirs with permeabilities less than 1 md. The first scenario evaluates gas predictions when complete production history is available to initiate a type curve match. Since in real case no prediction is undertake when the total history is known, this scenario only allows evaluating the correct performance of the program. The second scenario assumes that 75% of the production history is known to predict future gas production. The third scenario evaluates the prediction performance when 50% of the production history is available to initiate a prediction. Finally, 25% of the total gas production is also analyzed to predict future gas deliverabilities.

CHAPTER 4

RESULTS

This chapter presents the results obtained to predict long – term gas production based on the available gas production history. Two cases are discussed in this chapter to analyze the four proposed scenarios. Also, results for a set of 12 different cases are illustrated in tables. Graphic results and gas deliverability performance for cases using 50% and 25% of the total production history are presented in appendices A and B.

4.1 Moderate permeability gas reservoir

This case has a production history of 720 days (1.97 years). The initial gas in place is 9.588 Bcf; the reservoir permeability is 50 md. The well was produced under a constant pressure of 500 psia, with an initial reservoir pressure of 3500 psia. First of all, the complete history production was introduced to the program for prediction. As shown in Table 4.1, the matched parameters are almost the same as the actual parameters of the well.

Table 4.1 Predicted parameters for a moderate permeability gas reservoir using complete production history.

Parameter	Actual	Matched	Error difference, %
K, md	50	49.66	0.68
Pwf, psia	500	516.37	3.27
Gi, Bcf	9.588	9.609	0.22
Fndi	2.89	2.89	0
Xi	7.85	7.59	3.31

Table 4.2 presents the error differences between the actual flow rates and the predicted rates. As shown, the differences are minimal with a maximum error difference of 1.67% for the last point of the production history at 720 days. Figures 4.1 and 4.2 present the results for the production history and its matched curve utilizing Cartesian and logarithmic scales. As also seen, the curves match perfectly and it is difficult to see differences between actual data and predicted data.

Table 4.2 Predicted gas flow – rates for a moderate permeability gas reservoir using complete production history

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error difference, %
0.26	74143.16	73760.53	0.52
2.84	71942.50	71581.36	0.50
5.91	69485.73	69146.22	0.49
9.04	67124.71	66809.41	0.47
12.41	64741.45	64451.82	0.45
16.04	62337.07	62070.66	0.43
19.95	59912.99	59668.91	0.41
24.18	57469.37	57240.96	0.40
28.74	55007.75	54800.67	0.38
33.68	52528.54	52337.71	0.36
39.02	50034.04	49860.99	0.35
44.80	47525.47	47372.17	0.32
51.07	45004.99	44868.39	0.30
57.87	42474.05	42354.23	0.28
65.25	39935.02	39831.53	0.26
73.27	37390.08	37300.71	0.24
81.98	34841.86	34767.03	0.21
91.46	32292.02	32231.50	0.19
101.80	29743.38	29694.50	0.16
113.09	27197.46	27161.68	0.13
125.48	24656.41	24631.25	0.10
126.13	24529.45	24504.91	0.10
139.86	21995.48	21980.64	0.07
155.12	19469.75	19463.07	0.03
172.28	16953.39	16952.75	0.00
191.87	14447.75	14452.04	0.03
214.75	11953.71	11960.14	0.05
240.88	9596.07	9600.75	0.05
275.67	7127.50	7127.45	0.00
324.25	4673.78	4665.00	0.19
408.12	2236.73	2219.17	0.79
720.81	180.64	183.65	1.67

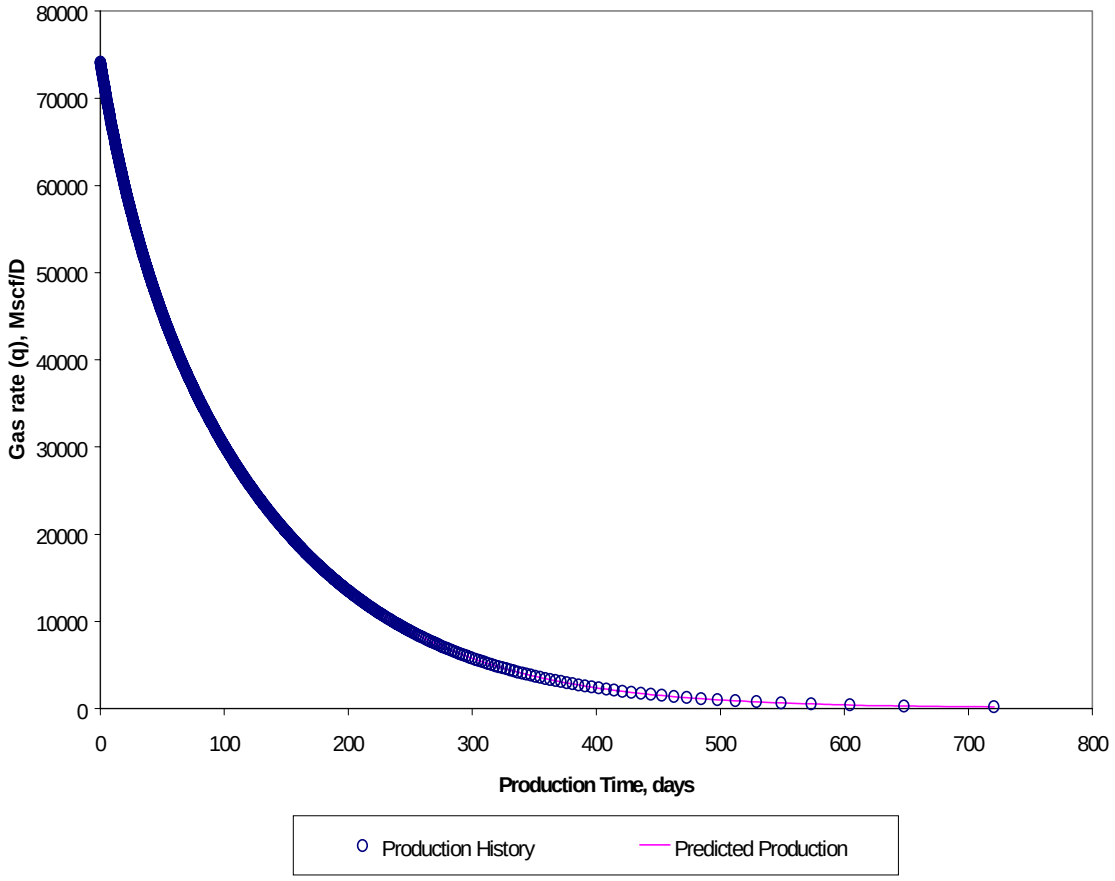


Figure 4.1 Gas well production forecast using complete production history for a moderate permeability gas reservoir (50 md)

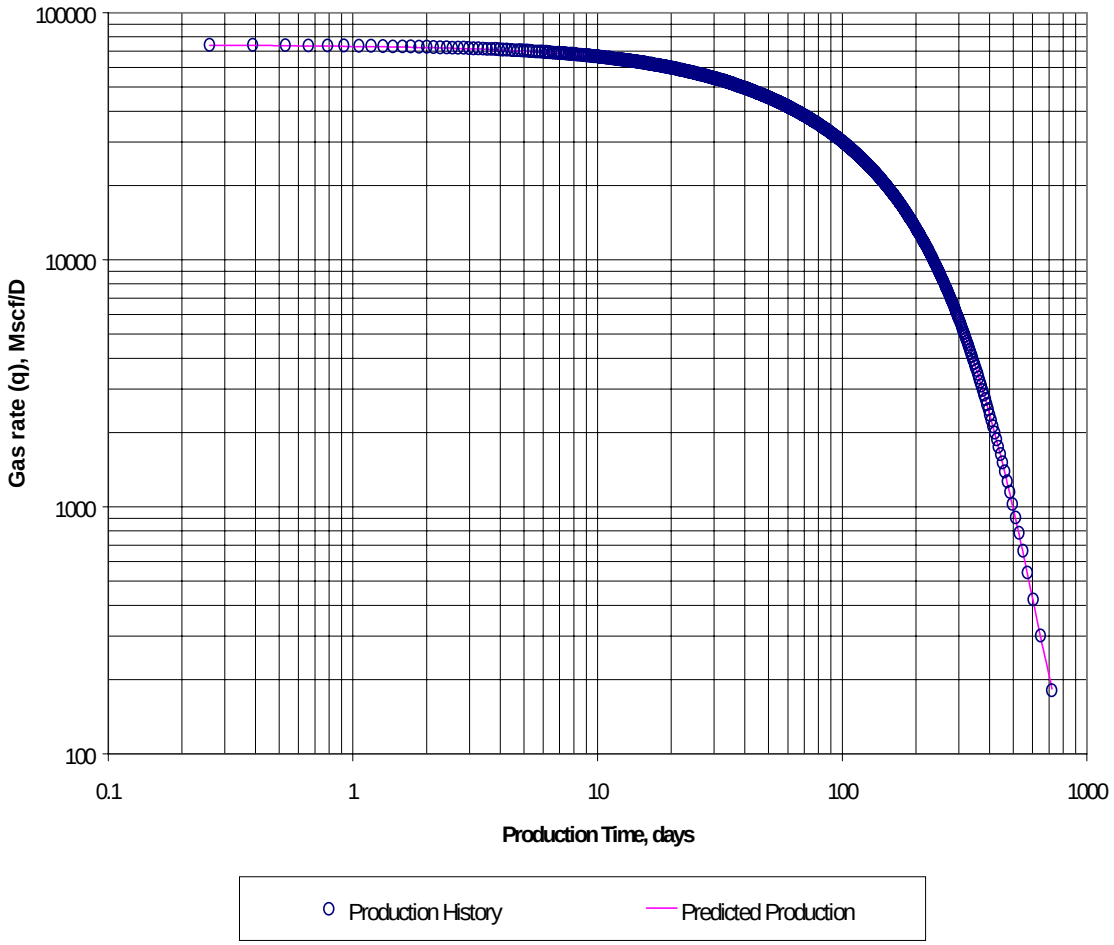


Figure 4.2 Gas well production forecast using complete production history for a moderate permeability gas reservoir (50 md), logarithmic scale.

A second scenario was analyzed when 75% of the total production history is known to predict future performance. It is important to highlight that 75% of the total production means 75% of the initial gas in place already produced by the well. Likewise, this concept applies to 50% and 25% of the total production. As a result, 232 days (0.63 years) of production were introduced to the computer program to forecast gas deliverability to 720 days. Table 4.3 shows the comparison between actual data and predicted data.

Table 4.3 Predicted results for a moderate permeability gas reservoir using 75% of the history production

Parameter	Actual	Matched	Error difference, %
K, md	50	49.98	0.04
Pwf, psia	500	496.01	0.80
Gi, Bcf	9.588	9.581	0.07
Fndi	2.89	2.90	0.35
Xi	7.85	7.92	0.89

As seen, excellent results were obtained with error differences less than 1% for the parameters in study. Table 4.4 shows minimal error differences for the predicted flow rates with a maximum flow rate difference of 6.33% at 720 days. Figure 4.3 shows the graphic comparison between actual data (production history) and the matched type curve. Figure 4.4 shows the graphic verification plotting the total production history and the matched curve. As seen, the matched curve fits production history very well. The logarithmic scale is preferred to show the results; since, this scale allows visualizing better differences between actual and predicted rates.

Table 4.4 Predicted gas flow-rates for a moderate permeability gas reservoir using 75% of the production history

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error difference, %
232.05	10339.31	10348.10	0.08
236.39	9967.54	9976.60	0.09
240.88	9596.07	9605.17	0.09
245.53	9224.87	9234.24	0.10
250.35	8854.01	8864.15	0.11
255.37	8483.47	8493.38	0.12
260.59	8113.24	8123.48	0.13
266.03	7743.30	7754.36	0.14
271.73	7373.72	7384.57	0.15
277.69	7004.46	7016.03	0.17
283.96	6635.54	6647.23	0.18
290.56	6266.94	6279.15	0.19
297.54	5898.70	5911.17	0.21
304.95	5530.80	5543.37	0.23
312.84	5163.27	5176.16	0.25
321.29	4796.09	4809.08	0.27
330.39	4429.29	4442.23	0.29
340.24	4062.86	4076.00	0.32
350.99	3696.82	3710.15	0.36
362.84	3331.17	3344.47	0.40
376.06	2965.93	2979.19	0.45
390.90	2601.11	2614.45	0.51
408.12	2236.73	2249.58	0.57
421.18	1994.05	2006.79	0.64
435.96	1751.57	1763.90	0.70
452.97	1509.29	1521.28	0.79
473.06	1267.22	1278.64	0.90
484.63	1146.27	1157.46	0.98
497.56	1025.37	1036.16	1.05
512.19	904.52	914.95	1.15
529.05	783.73	793.85	1.29
548.97	663.00	672.63	1.45
573.26	542.32	551.69	1.73
604.49	421.71	430.72	2.14
648.11	301.15	310.48	3.10
720.81	180.64	192.07	6.33

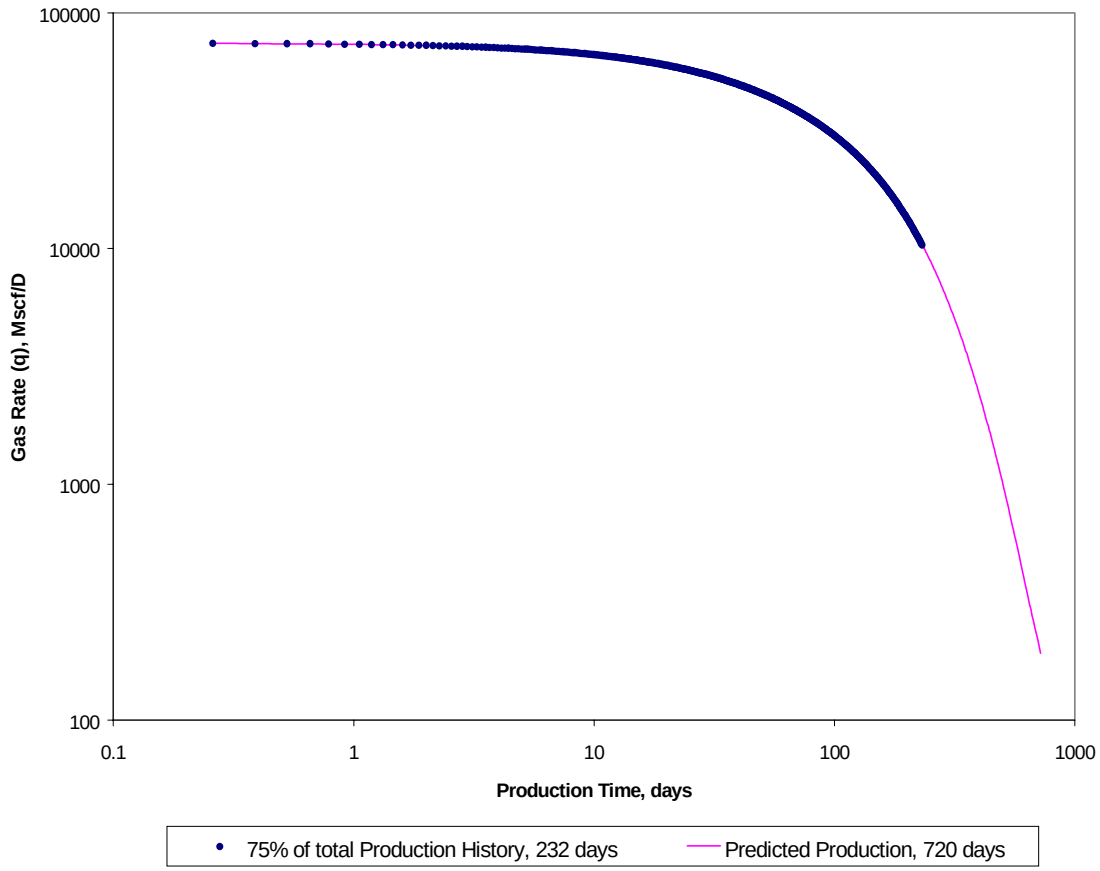


Figure 4.3 Gas well production forecast using 75% of the production history for a moderate permeability gas reservoir (50 md)

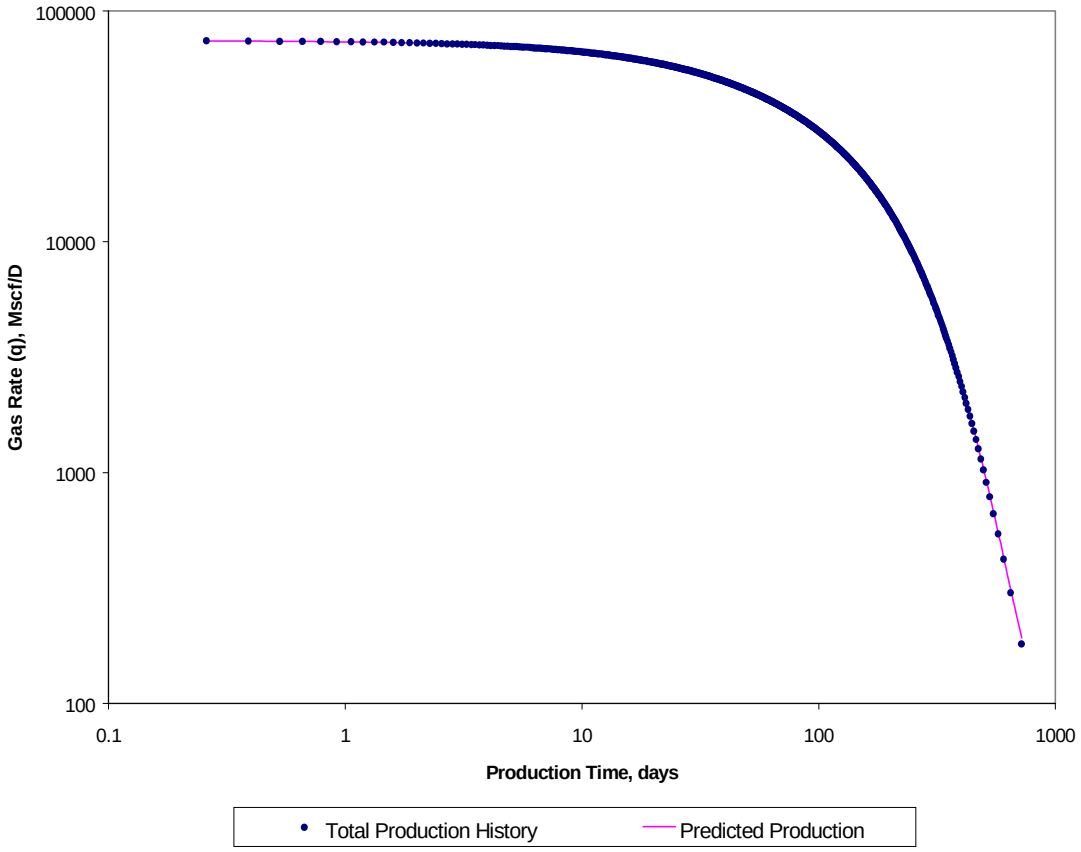


Figure 4.4 Graphic verification for a Gas well production forecast using 75% of the production history

The third scenario was analyzed with 50% of the total production to predict future gas deliverability. Thus, 101 days (0.28 years) of production were matched to forecast gas deliverability to 720 days.

Table 4.5 Predicted results for a moderate permeability gas reservoir using 50% of the history production

Parameter	Actual	Matched	Error difference, %
K, md	50	50.33	0.66
Pwf, psia	500	585.72	17.14
Gi, Bcf	9.588	9.715	1.32
Fndi	2.89	2.89	0.00
Xi	7.85	6.62	15.67

As is seen in Table 4.5 good error differences are obtained between actual and forecasted parameters. As shown, *Pwf* is the most critical parameter in the prediction. According to the accuracy of its prediction the length of an accurate forecast will vary. As shown in table 4.6 the prediction is able to forecast 84.07% of the *Gi* within a flow rate difference less than 10%. For the last value of the production history an error difference of 20.15% is obtained. Figure 4.5 shows the graphic comparison between available production history and the matched curve. Figure 4.6 shows the graphic verification using the total production history against the predicted curve. It is seen that the predicted values are slightly smaller than the actual ones.

Table 4.6 Predicted gas flow-rates for a moderate permeability gas reservoir using 50% of the production history

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	% of Gi Produced	Error difference, %
101.80	29743.38	29696.79	50.10	0.16
105.08	28979.00	28928.38	51.11	0.17
109.03	28087.97	28030.10	52.28	0.21
113.09	27197.46	27135.94	53.45	0.23
117.30	26307.36	26238.72	54.62	0.26
121.64	25418.20	25344.03	55.79	0.29
126.13	24529.45	24449.30	56.95	0.33
130.78	23641.75	23554.39	58.12	0.37
135.60	22754.87	22659.55	59.28	0.42
140.58	21869.00	21768.30	60.44	0.46
145.76	20984.08	20875.91	61.59	0.52
151.15	20100.38	19982.76	62.74	0.59
156.75	19217.62	19092.11	63.89	0.65
162.58	18336.18	18202.70	65.02	0.73
168.67	17455.81	17313.95	66.16	0.81
175.04	16576.84	16426.14	67.28	0.91
181.73	15699.22	15537.50	68.40	1.03
188.75	14822.85	14652.24	69.52	1.15
196.15	13947.99	13766.82	70.62	1.30
203.97	13074.54	12883.29	71.72	1.46
212.28	12202.55	11999.78	72.81	1.66
221.14	11332.17	11118.08	73.89	1.89
230.64	10463.32	10237.23	74.96	2.16
240.88	9596.07	9358.21	76.03	2.48
252.00	8730.46	8481.22	77.08	2.85
264.19	7866.59	7605.82	78.13	3.31
277.69	7004.46	6732.61	79.17	3.88
292.85	6144.17	5862.88	80.19	4.58
310.16	5285.74	4996.97	81.21	5.46
333.58	4307.10	4015.10	82.36	6.78
362.84	3331.17	3044.39	83.51	8.61
380.82	2844.27	2564.06	84.07	9.85
421.18	1994.05	1741.15	85.05	12.68
720.81	180.64	144.24	87.13	20.15

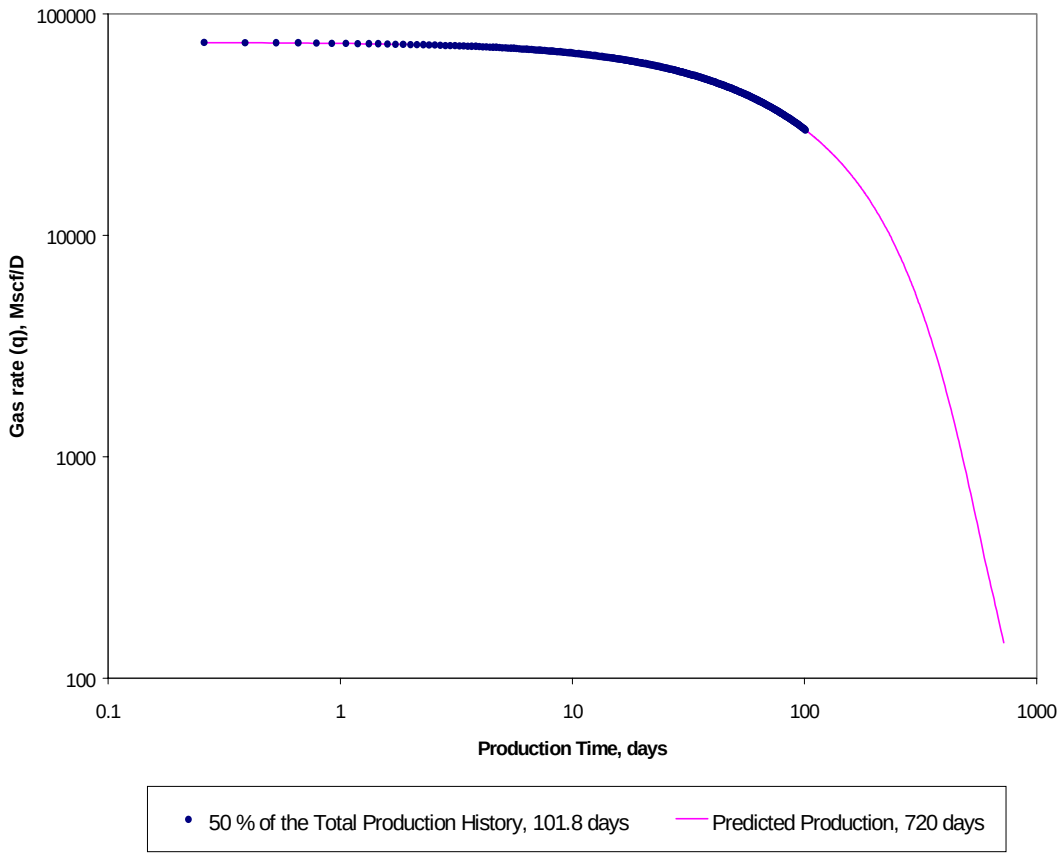


Figure 4.5 Gas well production forecast using 50% of the production history for a moderate permeability gas reservoir (50 md).

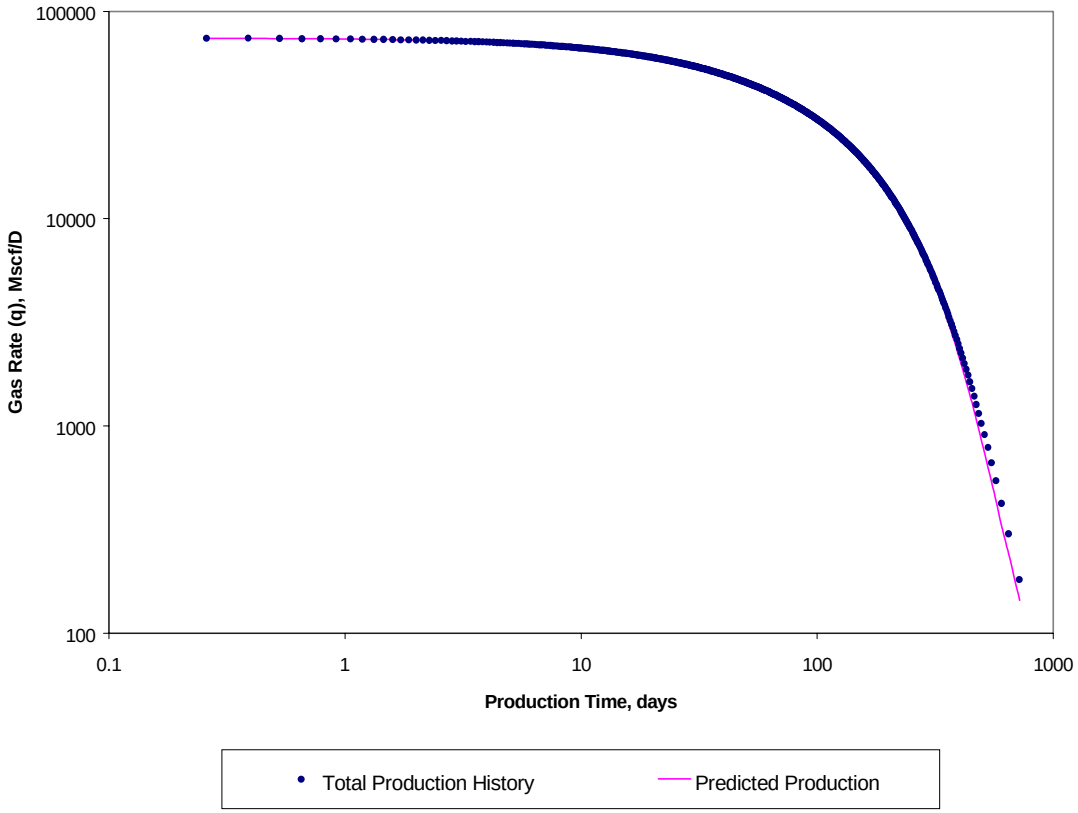


Figure 4.6 Graphic verification for a Gas well production forecast using 50% of the production history.

For the final scenario, 25% of the total production history is accounted to predict future gas deliverability. Thus, 39 days (0.11 years) of production were matched to forecast gas deliverability to 720 days.

Table 4.7 Predicted results for a moderate permeability gas reservoir using 25% of the history production

Parameter	Actual	Matched	Error difference, %
K, md	50	50.33	0.66
Pwf, psia	500	589.28	17.86
Gi, Bcf	9.588	9.715	1.32
Fndi	2.89	2.89	0.00
Xi	7.85	6.58	16.18

As shown in table 4.7, similar error differences were obtained as in 50% scenario. Again, *Pwf* is the most critical parameter to predict with an error difference of 17.86%. Table 4.8 shows that the prediction is able to forecast until 84% of the *Gi* recovered within an error difference in flow-rate less than 10%. For the last value of the production history an error difference in flow-rate of 11.32% is obtained. Figure 4.7 shows the graphic comparison between available production history and the matched curve. Figure 4.8 shows the graphic verification using the total production history against the predicted curve. It is shown that the predicted values are slightly smaller than the actual ones.

Table 4.8 Predicted gas flow-rates for a moderate permeability gas reservoir using 25% of the production history

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	% of Gi produced	Error difference, %
39.57	49783.74	49795.05	25.03	0.02
43.02	48279.38	48285.54	26.78	0.01
46.63	46770.45	46774.81	28.57	0.01
50.42	45257.41	45258.63	30.39	0.00
54.40	43740.73	43738.12	32.23	0.01
58.58	42220.37	42213.97	34.11	0.02
62.97	40697.58	40686.21	36.00	0.03
67.59	39171.90	39153.31	37.92	0.05
72.44	37644.77	37619.86	39.86	0.07
77.54	36116.45	36083.70	41.82	0.09
82.90	34586.82	34547.15	43.79	0.11
88.54	33057.04	33009.62	45.77	0.14
94.47	31527.21	31473.14	47.77	0.17
100.73	29997.88	29934.29	49.77	0.21
107.32	28469.86	28397.33	51.78	0.25
114.28	26942.98	26861.20	53.78	0.30
121.64	25418.20	25325.58	55.79	0.36
129.44	23895.36	23790.39	57.79	0.44
137.71	22375.21	22259.02	59.78	0.52
146.52	20857.77	20728.78	61.76	0.62
155.93	19343.68	19201.03	63.72	0.74
166.03	17832.96	17674.83	65.67	0.89
177.86	16200.54	16026.56	67.76	1.07
189.78	14697.75	14506.12	69.67	1.30
202.83	13199.23	12988.63	71.56	1.60
217.27	11704.97	11475.68	73.43	1.96
233.48	10215.33	9965.80	75.27	2.44
252.00	8730.46	8461.12	77.08	3.09
273.68	7250.59	6962.10	78.87	3.98
299.97	5776.04	5471.75	80.63	5.27
333.58	4307.10	3997.00	82.36	7.20
380.82	2844.27	2549.12	84.07	10.38
462.56	1388.23	1162.44	85.75	16.26
720.81	180.64	160.19	87.13	11.32

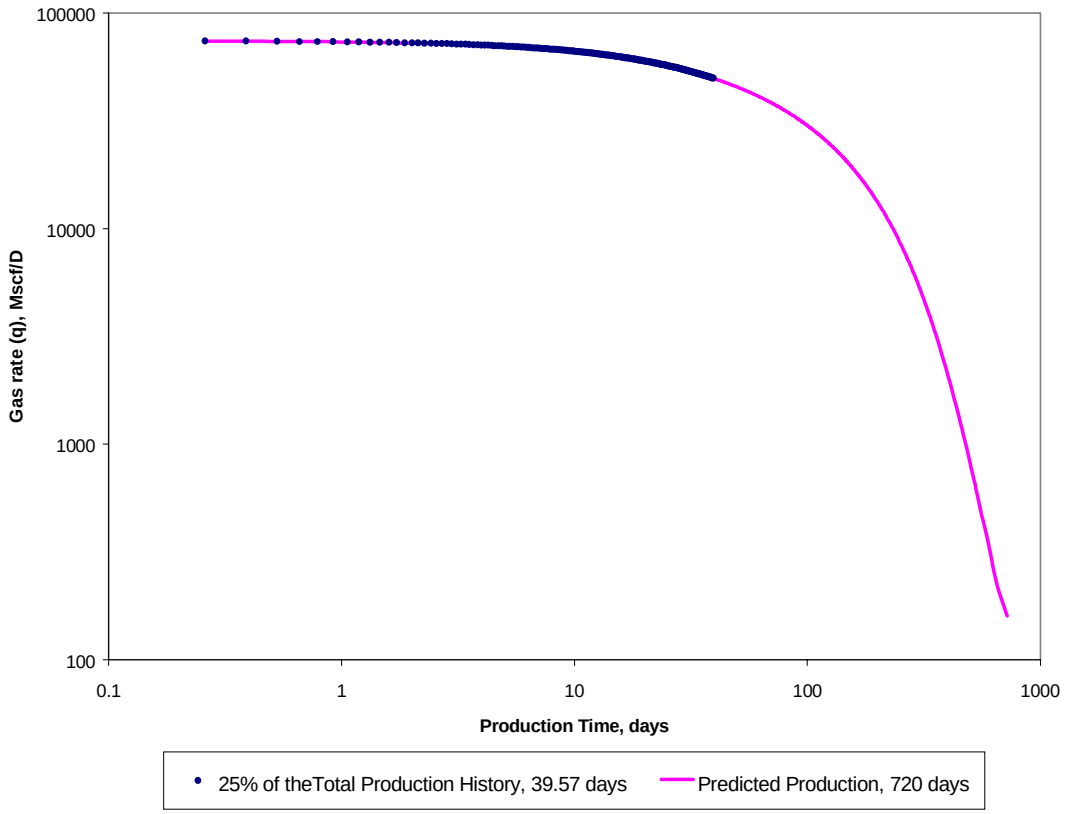


Figure 4.7 Gas well production forecast using 25% of the production history for a moderate permeability gas reservoir (50 md).

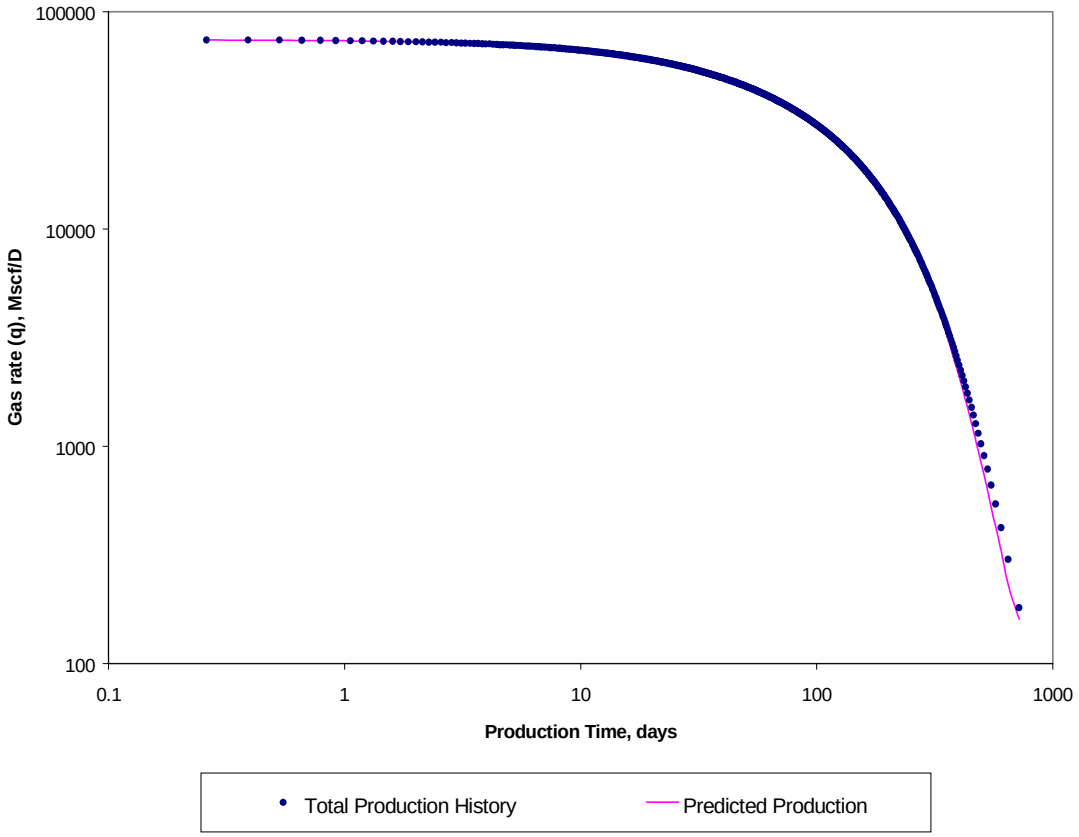


Figure 4.8 Graphic verification for a Gas well production forecast using 25% of the production history.

4.2 Low Permeability Gas Reservoir

This gas production history lasts up to 12285.24 days (33.6 years). The initial gas in place is 0.849 Bcf, the reservoir permeability is 0.68 md. The well produced under a constant pressure of 600 psia, with an initial reservoir pressure of 1900 psia. As the gas production for moderate permeability, the same four scenarios were analyzed for this production. Table 4.9 shows the comparison between the actual values for K, Pwf, Gi, Fndi, and Xi with the predicted ones using the complete production history to match itself.

Table 4.9 Predicted results for a low permeability gas reservoir using complete production history

Parameter	Actual	Matched	Error difference, %
K, md	0.68	0.68	0.00
Pwf, psia	600	620.67	3.44
Gi, Bcf	0.849	0.86	1.30
Fndi	1.04	1.04	0.00
Xi	3.54	3.42	3.39

As is observed an excellent general match was obtained with no difference in permeability and non-darcy effects. Table 4.10 shows the comparison between actual values and predicted values for flowrates. As seen, the error differences are less than 1% with an error of 0.36% at 12285.24 days. Figure 4.9 shows the graphic comparison for this match.

Table 4.10 Predicted gas flow-rates for a low permeability gas reservoir using complete production history

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %
11.44	420.52	417.25	0.78
52.52	405.11	402.13	0.74
95.31	389.85	387.15	0.69
139.87	374.77	372.32	0.65
186.29	359.84	357.66	0.61
241.84	343.01	341.09	0.56
300.22	326.41	324.73	0.51
361.62	310.05	308.61	0.46
426.32	293.95	292.74	0.41
494.6	278.11	277.10	0.36
566.78	262.54	261.72	0.31
633.44	249.15	248.47	0.27
703.60	235.98	235.45	0.23
777.62	223.04	222.63	0.18
855.86	210.33	210.03	0.14
938.69	197.85	197.67	0.09
1026.64	185.63	185.53	0.06
1134.10	171.96	171.95	0.01
1234.90	160.27	160.33	0.03
1358.89	147.24	147.35	0.08
1493.60	134.55	134.72	0.13
1640.73	122.23	122.43	0.16
1781.32	111.74	111.96	0.20
1934.85	101.54	101.77	0.23
2129.08	90.24	90.47	0.25
2347.55	79.33	79.54	0.26
2596.34	68.80	68.99	0.27
2883.81	58.68	58.83	0.26
3222.49	48.97	49.08	0.22
3631.99	39.67	39.74	0.17
4074.38	31.87	31.89	0.07
4635.61	24.41	24.39	0.08
5395.86	17.26	17.21	0.27
6557.22	10.46	10.38	0.73
8008.91	5.80	5.73	1.20
12285.24	1.31	1.31	0.36

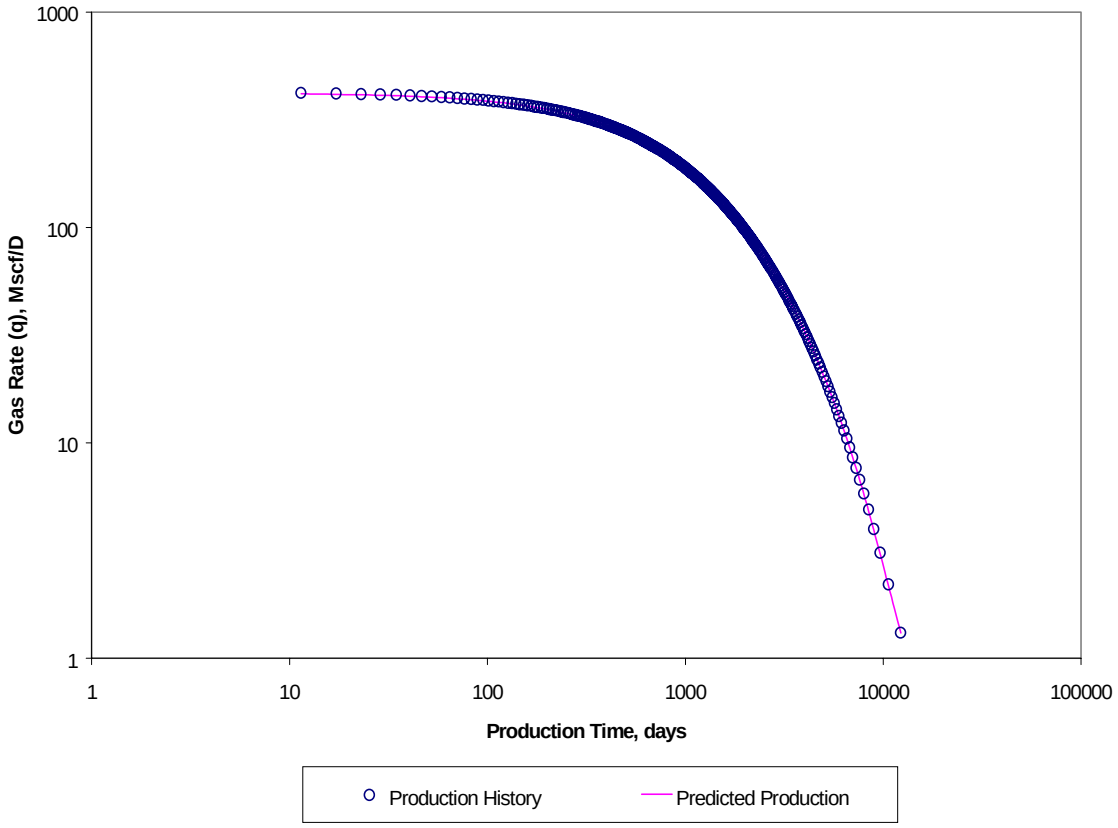


Figure 4.9 Gas well production forecast using complete production history for a low permeability gas reservoir (0.68 md).

Table 4.11 shows the comparison between actual values and predicted values for *k, Pwf, Gi, Fndi, and Xi* when 75% of the total production history is available to initiate the prediction.

Table 4.11 Predicted results for a low permeability gas reservoir using 75% of the total production history

Parameter	Actual	Matched	Error difference, %
K, md	0.68	0.68	0.00
Pwf, psia	600	623.89	3.98
Gi, Bcf	0.849	0.86	1.30
Fndi	1.04	1.04	0.00
Xi	3.54	3.4	3.95

Thus, the production history for the first 2467 days was used for history matching, and the remaining data were used for comparison with predicted rates as shown in table 4.12. As mentioned before, *Pwf* is the variable with larger error difference but with no incidence in the results. In general the error in predicting rates is less than 2% with predicted values slightly less than the actual ones. The maximum error difference occurs at the last point of the total production history with 5.13%. Figure 4.10 shows the graphic verification using the complete production history to be compared with the predicted values. The curves fit very well each other.

Table 4.12 Predicted gas flow-rates for a low permeability gas reservoir using 75% of data

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
2467.73	74.02	74.05	0.03	54.35
2530.86	71.40	71.43	0.04	54.88
2629.90	67.52	67.54	0.03	55.68
2699.00	64.96	64.98	0.03	56.22
2770.73	62.43	62.44	0.02	56.75
2883.81	58.68	58.68	0.01	57.55
3003.96	54.99	54.99	0.01	58.34
3132.06	51.36	51.34	0.03	59.13
3222.49	48.97	48.94	0.06	59.66
3317.26	46.61	46.57	0.08	60.19
3468.48	43.11	43.06	0.12	60.98
3575.98	40.81	40.75	0.14	61.50
3689.58	38.54	38.47	0.18	62.02
3872.86	35.18	35.10	0.24	62.81
4074.38	31.87	31.78	0.29	63.59
4297.05	28.63	28.52	0.37	64.37
4459.65	26.51	26.39	0.45	64.88
4635.61	24.41	24.28	0.52	65.40
4827.18	22.33	22.20	0.57	65.91
5037.37	20.29	20.15	0.71	66.43
5269.93	18.26	18.12	0.78	66.94
5529.50	16.27	16.12	0.90	67.45
5985.83	13.33	13.19	1.08	68.22
6557.22	10.46	10.31	1.39	68.98
7035.77	8.57	8.44	1.50	69.49
8008.91	5.80	5.69	1.83	70.25
8448.43	4.89	4.80	1.90	70.51
8987.08	3.98	3.91	1.72	70.76
9681.47	3.09	3.04	1.62	71.01
10656.26	2.20	2.19	0.56	71.26
12285.24	1.31	1.38	5.13	71.51

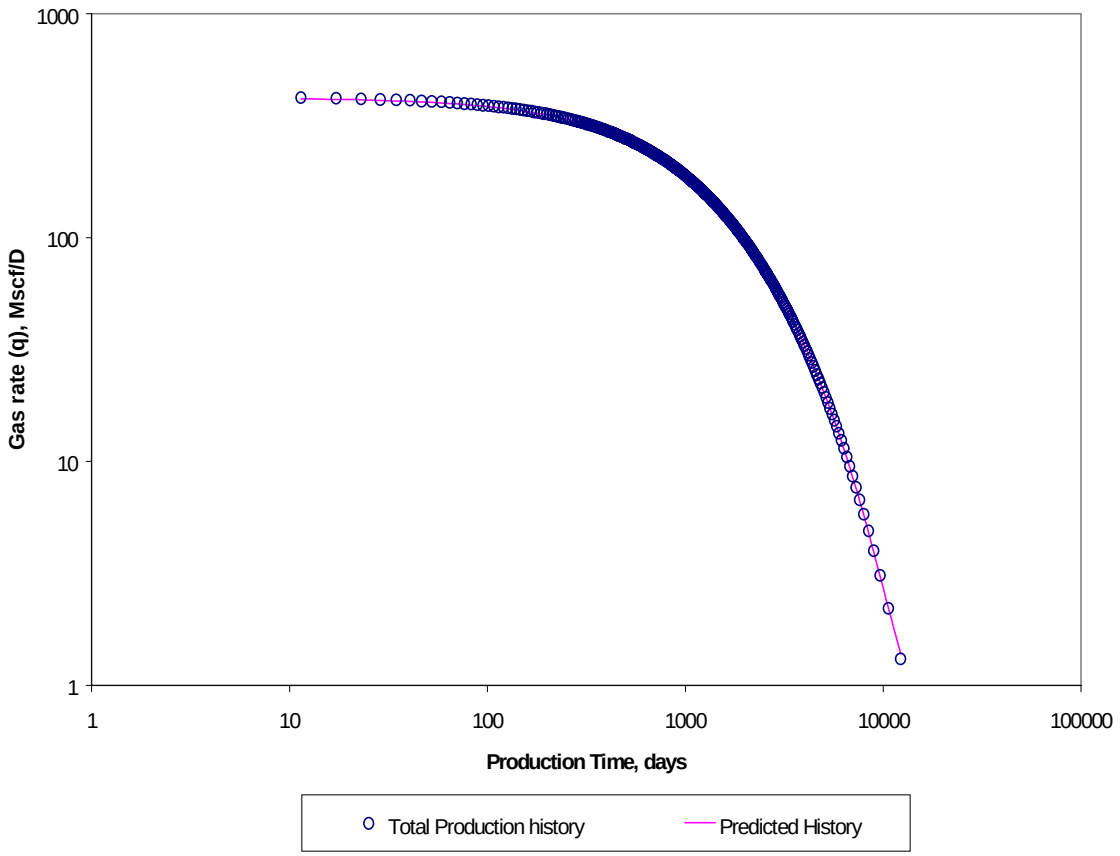


Figure 4.10 Gas well production forecast using 75% of total production history for a low permeability gas reservoir (0.68 md).

Table 4.13 shows the comparison between actual parameters and predicted values when 50% of the total data (1148 days) is available to initiate the prediction.

Table 4.13 Predicted results for a low permeability gas reservoir 50% of the total data

Parameter	Actual	Matched	Error difference, %
K, md	0.68	0.71	4.41
Pwf, psia	600	690.16	15.03
Gi, Bcf	0.849	0.891	4.95
Fndi	1.04	1.04	0.00
Xi	3.54	3.05	13.84

As shown, fair estimations were obtained showing *Pwf* as the variable with largest error percentage. As a result the prediction is able to estimate gas deliverabilities until 5823.28 days (15,95 years) in a range less than 10% in flow rates difference. As also shown in table 4.14 the maximum flow rate error occurs at last point of the total production history (12285 days) with 16.32%. Figure 4.11 shows the graphic verification using complete production history for this purpose. As shown, predicted values show a slight deviation from actual ones at the end of the production.

Table 4.14 Predicted gas flow-rates for a low permeability gas reservoir using 50% of data

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
1148.09	170.27	170.55	0.16	36.76
1205.40	163.58	163.77	0.11	37.88
1264.95	156.98	157.07	0.06	39.00
1342.84	148.85	148.82	0.02	40.40
1408.06	142.44	142.32	0.08	41.51
1493.60	134.55	134.32	0.17	42.89
1565.49	128.35	128.02	0.26	44.00
1640.73	122.23	121.80	0.35	45.10
1739.92	114.71	114.17	0.47	46.48
1845.42	107.34	106.68	0.62	47.85
1958.01	100.11	99.33	0.78	49.21
2053.69	94.43	93.57	0.92	50.30
2154.96	88.85	87.90	1.07	51.38
2262.44	83.37	82.33	1.25	52.46
2376.85	77.99	76.85	1.46	53.54
2499.02	72.70	71.49	1.67	54.61
2629.90	67.52	66.22	1.92	55.68
2807.71	61.18	59.78	2.28	57.02
2963.05	56.22	54.76	2.60	58.08
3132.06	51.36	49.84	2.96	59.13
3317.26	46.61	45.03	3.39	60.19
3575.98	40.81	39.18	3.99	61.50
3872.86	35.18	33.52	4.73	62.81
4146.02	30.79	29.11	5.44	63.85
4459.65	26.51	24.85	6.28	64.88
4827.18	22.33	20.71	7.25	65.91
5269.93	18.26	16.71	8.47	66.94
5823.28	14.31	12.88	10.00	67.97
6784.37	9.51	8.32	12.56	69.24
7035.77	8.57	7.45	13.13	69.49
7317.86	7.64	6.58	13.86	69.75
7638.01	6.72	5.72	14.85	70.00
8008.91	5.80	4.90	15.52	70.25
8448.43	4.89	4.11	15.97	70.51
8987.08	3.98	3.33	16.42	70.76
9681.47	3.09	2.53	18.05	71.01
10656.26	2.20	1.84	16.32	71.26

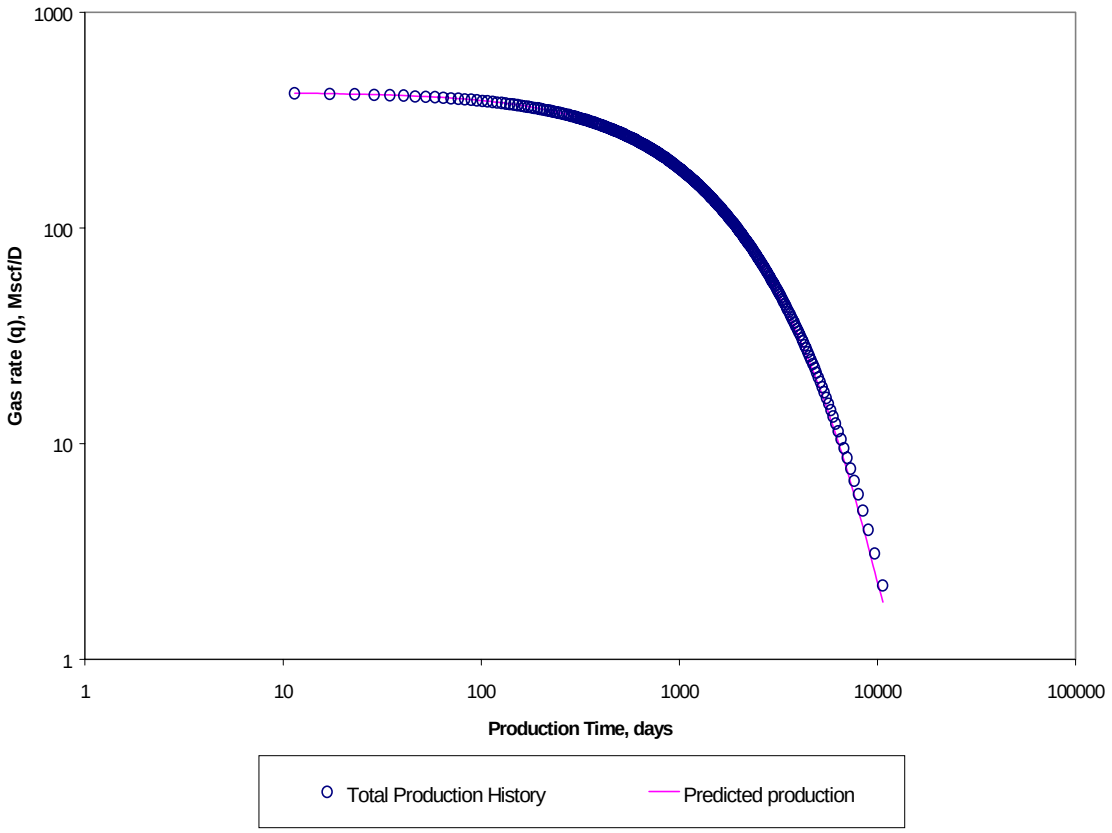


Figure 4.11 Gas well production forecast using 50% of total production history for a low permeability gas reservoir (0.68 md).

Table 4.15 shows the last analyzed scenario using the 25% of the data, (451,51 days, 1.23 years) to predict future deliverability at 12285 days.

Table 4.15 Predicted results for a low permeability gas reservoir using 25% of the total data

Parameter	Actual	Matched	Error difference, %
K, md	0.68	0.71	4.41
Pwf, psia	600	700.16	16.69
Gi, Bcf	0.849	0.884	4.12
Fndi	1.04	1.04	0.00
Xi	3.54	3	15.25

Table 4.16 shows the relation of predicted flow rates and flow rates for actual data. As is seen the prediction allows forecasting until 4827 days with an error difference in flow rates less than 10%. For the last point of the prediction 10656.26 days error difference is 21.78%. Figure 4.12 shows graphic verification for the prediction using the complete production history.

Table 4.16 Predicted gas flow-rates for a low permeability gas reservoir using 25% of data

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
443.06	289.96	289.33	0.22	18.30
485.89	280.07	279.37	0.25	19.73
530.21	270.29	269.51	0.29	21.16
576.11	260.62	259.76	0.33	22.59
633.44	249.15	248.21	0.38	24.30
693.34	237.85	236.82	0.43	26.01
756.06	226.71	225.59	0.49	27.72
821.78	215.75	214.53	0.57	29.43
890.77	204.95	203.64	0.64	31.13
950.93	196.09	194.70	0.71	32.54
1013.74	187.36	185.89	0.79	33.95
1079.38	178.75	177.20	0.87	35.36
1148.09	170.27	168.64	0.96	36.76
1220.08	161.93	160.21	1.06	38.16
1295.63	153.71	151.92	1.16	39.56
1375.10	145.63	143.77	1.28	40.95
1458.85	137.69	135.74	1.41	42.34
1547.20	129.89	127.87	1.56	43.72
1660.08	120.71	118.60	1.75	45.38
1760.50	113.22	111.04	1.92	46.75
1867.36	105.88	103.62	2.13	48.12
1981.43	98.68	96.36	2.35	49.48
2103.57	91.63	89.26	2.59	50.84
2234.98	84.73	82.30	2.87	52.19
2376.85	77.99	75.50	3.19	53.54
2530.86	71.40	68.87	3.54	54.88
2699.00	64.96	62.40	3.94	56.22
2883.81	58.68	56.10	4.40	57.55
3132.06	51.36	48.76	5.06	59.13
3416.76	44.27	41.68	5.86	60.71
3689.58	38.54	35.98	6.64	62.02
4004.78	32.97	30.47	7.59	63.33
4376.80	27.57	25.16	8.75	64.62
4827.18	22.33	20.06	10.15	65.91
5395.86	17.26	15.19	11.97	67.20
6161.11	12.37	10.59	14.42	68.48
10656.26	2.20	1.72	21.78	71.26

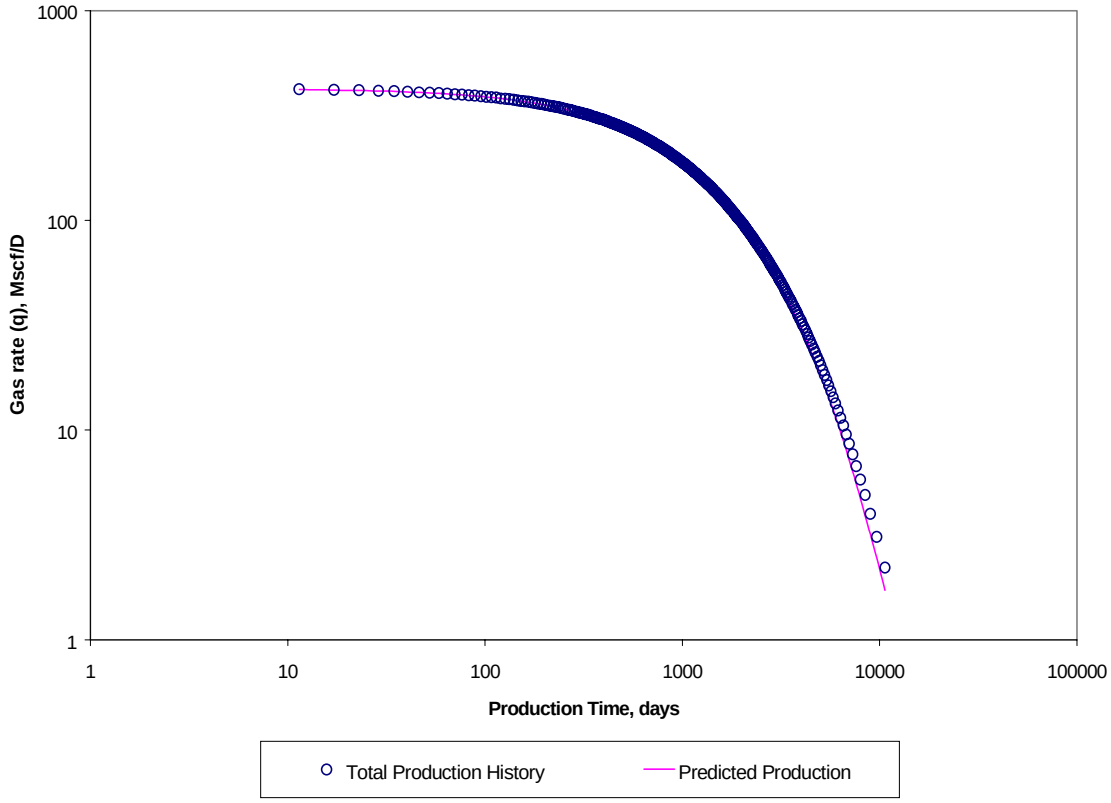


Figure 4.12 Gas well production forecast using 25% of total production history for a low permeability gas reservoir (0.68 md).

4.3 Summary of results

Tables 4.18, 4.19, 4.20, and 4.21 shows the results obtained for 12 different cases utilizing 100%, 75%, 50% and 25% of their total production history. As is seen, the difference in error percentage between actual parameters and predicted parameters were computed. Also an average error is calculated for the five parameters in study. Table 4.17 shows a comparison of the obtained average error for the four scenarios.

Table 4.17 Summary of average error differences between actual parameters and predicted parameters for 4 different scenarios

Percentage of Total Production History	Avg Error % for K	Avg Error % for Pwf	Avg Error % for Gi	Avg Error % for Fndi	Avg Error % for Xi
100	0.84	2.09	0.54	0.13	2.12
75	0.88	2.40	0.91	0.25	2.58
50	1.36	11.63	1.60	0.05	10.74
25	2.92	17.03	2.54	0.34	14.39

Table 4.18 Predicted Results for 12 Gas well production cases using 100% of the production history.

case #	Actua K,	Pred/ K, md	Error %	Actual Pwf	Predicted Pwf	Error %	Actual Gi	Predicted Gi	Error %	Actual Fndi	Predicted Fndi	Error %	Actual Xi	Predicted Xi	Error %
1	90	90.21	0.23	315	309.24	1.83	11.467	11.432	0.31	2.04	2.05	0.49	5.96	6.06	1.68
2	75	75.51	0.68	300	294.64	1.79	5.469	5.472	0.05	3.17	3.18	0.32	12.11	12.34	1.90
3	50	49.66	0.68	500	516.37	3.27	9.588	9.609	0.22	2.89	2.89	0.00	7.85	7.59	3.31
4	38	37.75	0.66	440	445.7	1.30	16.178	16.176	0.01	1.98	1.98	0.00	7.66	7.56	1.31
5	10	10.03	0.30	280	279.52	0.17	5.154	5.146	0.16	1.29	1.3	0.78	8.75	8.77	0.23
6	7.5	7.48	0.27	500	509.92	1.98	6.122	6.125	0.05	1.54	1.54	0.00	7.53	7.38	1.99
7	4	4.02	0.50	260	264.85	1.87	2.164	2.177	0.60	1.14	1.14	0.00	7.37	7.23	1.90
8	3.3	3.29	0.30	275	279.72	1.72	1.303	1.304	0.08	1.12	1.12	0.00	7.51	7.38	1.73
9	2.41	2.44	1.24	250	240.51	3.80	0.512	0.505	1.37	1.08	1.08	0.00	6.56	6.82	3.96
10	0.68	0.68	0.00	600	620.67	3.44	0.849	0.86	1.30	1.04	1.04	0.00	3.54	3.42	3.39
11	0.5	0.5	0.00	400	389.66	2.58	0.398	0.396	0.50	1.05	1.05	0.00	5.96	6.12	2.68
12	0.38	0.37	2.63	545	552.5	1.38	0.485	0.476	1.86	1.04	1.04	0.00	3.65	3.6	1.37
Avg			0.62			2.09			0.54			0.13			2.12

Table 4.19 Predicted Results for 12 Gas well production cases using 75% of the production history.

case #	Actua K,	Pred/ K, md	Error %	Actual Pwf	Predicted Pwf	Error %	Actual Gi	Predicted Gi	Error %	Actual Fndi	Predicted Fndi	Error %	Actual Xi	Predicted Xi	Error %
1	90	90.06	0.07	315	321.83	2.17	11.467	11.484	0.15	2.04	2.04	0.00	5.96	5.87	1.51
2	75	74.15	1.13	300	288.5	3.83	5.469	5.38	1.63	3.17	3.16	0.32	12.11	12.61	4.13
3	50	49.98	0.04	500	496.01	0.80	9.588	9.581	0.07	2.89	2.9	0.35	7.85	7.92	0.89
4	38	35.85	5.66	440	421.98	4.10	16.178	15.561	3.81	1.98	1.95	1.52	7.66	8	4.44
5	10	9.97	0.30	280	250.83	10.42	5.154	5.118	0.70	1.29	1.3	0.78	8.75	9.81	12.11
6	7.5	7.51	0.13	500	499.29	0.14	6.122	6.123	0.02	1.54	1.54	0.00	7.53	7.55	0.27
7	4	3.99	0.25	260	257.8	0.85	2.164	2.162	0.09	1.14	1.14	0.00	7.37	7.44	0.95
8	3.3	3.29	0.30	275	277.86	1.04	1.303	1.304	0.08	1.12	1.12	0.00	7.51	7.43	1.07
9	2.41	2.41	0.00	250	249.22	0.31	0.512	0.512	0.00	1.08	1.08	0.00	6.56	6.58	0.30
10	0.68	0.68	0.00	600	623.89	3.98	0.849	0.860	1.30	1.04	1.04	0.00	3.54	3.4	3.95
11	0.5	0.5	0.00	400	402.86	0.72	0.398	0.399	0.25	1.05	1.05	0.00	5.96	5.91	0.84
12	0.38	0.37	2.63	545	542.54	0.45	0.485	0.471	2.89	1.04	1.04	0.00	3.65	3.67	0.55
Avg			0.88			2.40			0.91			0.25			2.58

Table 4.20 Predicted Results for 12 Gas well production cases using 50% of the production history.

case #	Actua K,	Pred/ K, md	Error %	Actual Pwf	Predicted Pwf	Error %	Actual Gi	Predicted Gi	Error %	Actual Fndi	Predicted Fndi	Error %	Actual Xi	Predicted Xi	Error %
1	90	90.06	0.07	315	319.75	1.51	11.467	11.484	0.15	2.04	2.04	0	5.96	5.87	1.51
2	75	74.97	0.04	300	262.02	12.66	5.469	5.435	0.62	3.17	3.17	0	12.11	13.93	15.03
3	50	50.33	0.66	500	585.72	17.14	9.588	9.715	1.32	2.89	2.89	0	7.85	6.62	15.67
4	38	37.38	1.63	440	438.03	0.45	16.178	16.001	1.09	1.98	1.98	0	7.66	7.7	0.52
5	10	10.03	0.30	280	304.82	8.86	5.154	5.182	0.35	1.29	1.29	0	8.75	8.01	8.46
6	7.5	7.3	2.67	500	551.54	10.31	6.122	6.036	1.40	1.54	1.53	0.65	7.53	6.8	9.69
7	4	4.05	1.25	260	329.14	26.59	2.164	2.208	2.03	1.14	1.14	0	7.37	5.79	21.44
8	3.3	3.29	0.30	275	251.84	8.42	1.303	1.296	0.54	1.12	1.12	0	7.51	8.22	9.45
9	2.41	2.42	0.41	250	281.7	12.68	0.512	0.516	0.78	1.08	1.08	0	6.56	5.8	11.59
10	0.68	0.71	4.41	600	690.16	15.03	0.849	0.891	4.95	1.04	1.04	0	3.54	3.05	13.84
11	0.5	0.51	2.00	400	501.86	25.47	0.398	0.41	3.02	1.05	1.05	0	5.96	4.7	21.14
12	0.38	0.37	2.63	545	55.54	0.45	0.485	0.471	2.89	1.04	1.04	0	3.65	3.67	0.55
Avg			1.36			11.63			1.60			0.05			10.74

Table 4.21 Predicted Results for 12 Gas well production cases using 25% of the production history.

case #	Actua K,	Pred/ K, md	Error %	Actual Pwf	Predicted Pwf	Error %	Actual Gi	Predicted Gi	Error %	Actual Fndi	Predicted Fndi	Error %	Actual Xi	Predicted Xi	Error %
1	90	90.06	0.07	315	321.83	2.17	11.467	11.484	0.15	2.04	2.04	0	5.96	5.83	2.18
2	75	75.49	0.65	300	401.82	33.94	5.469	5.509	0.73	3.17	3.16	0.32	12.11	8.94	26.18
3	50	50.33	0.66	500	589.28	17.86	9.588	9.715	1.32	2.89	2.89	0	7.85	6.58	16.18
4	38	35.85	5.66	440	421.98	4.10	16.178	15.561	3.81	1.98	1.95	1.52	7.66	8	4.44
5	10	10.76	7.60	280	317.8	13.50	5.154	5.398	4.73	1.29	1.31	1.55	8.75	7.66	12.46
6	7.5	7.75	3.33	500	616.4	23.28	6.122	6.433	5.08	1.54	1.53	0.65	7.53	6.04	19.79
7	4	4.05	1.25	260	321.25	23.56	2.164	2.192	1.29	1.14	1.14	0	7.37	5.94	19.40
8	3.3	3.29	0.30	275	266.71	3.01	1.303	1.304	0.08	1.12	1.12	0	7.51	7.75	3.20
9	2.41	2.47	2.49	250	336.74	34.70	0.512	0.526	2.73	1.08	1.08	0	6.56	4.83	26.37
10	0.68	0.71	4.41	600	700.16	16.69	0.849	0.884	4.12	1.04	1.04	0	3.54	3	15.25
11	0.5	0.53	6.00	400	503.28	25.82	0.398	0.418	5.03	1.05	1.05	0	5.96	4.68	21.48
12	0.38	0.37	2.63	545	576.1	5.71	0.485	0.478	1.44	1.04	1.04	0	3.65	3.44	5.75
Avg			2.92			17.03			2.54			0.34			14.39

CHAPTER 5

DISCUSSION

As observed in Chapter 4 and appendices A and B, satisfactory results were obtained. As a common trend, it is observed in Table 4.17 that the accuracy of the results improves as the amount of data available for the prediction increases. The first scenario allowed evaluating the correct performance of the program when the complete production history is predicted. Average errors less than 1 % in predicting permeability and initial gas in place were obtained. Error averaged less than 2.5% in *Pwf* and X_i were obtained. Similar results were obtained for prediction with 75% of the total production, where average errors for all the predicted parameters were less than 3%. In this case, it is noticeable that *Pwf* is the variable with major impact on the prediction. In general, the same trend was observed in the other scenarios. For the third scenario, 50% of the total production is assumed to be available to forecast future performance. The predictions for K and G_i are quite reasonable allowing reliable predictions for F_{NDi} and Gi. It is observed that the prediction of *Pwf* impacts the prediction. As shown in appendix A, the procedure is not able to predict the last point of some histories with less than 10% error. However, in general the predictions with 50% of total data are accurate to about 84% of the initial gas in place. These results

are satisfactory since in real cases gas recoveries greater than 90% are difficult to achieve due to geological and mechanical conditions of the reservoir and the well. Also, the amount of data contain in 50% and 25% of the total production history generally falls into the flat zone of the type curves where it is difficult to obtain a unique match. In this region, type curves do not bend and this can cause the type curves not close to the production history yield small average least square differences.

The same behavior is observed when 25% of the total history production is available for prediction. In these cases a slight deviation at the end of the predicted curve is observed. In some of the cases this deviation does not impact gas deliverabilities since at these stages the magnitudes of flow rates are small and the well is almost depleted. Also, satisfactory results were obtained since an average of 78% of the total Gi provides flow rates with less than 10% error.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

The following conclusions are drawn from this study:

- Non-Darcy effects, and the variation of gas viscosity and compressibility due to changes in pressure are accounted in the proposed type curves to estimate gas reserves and gas deliverabilities.

- A computer program has been developed to automatically match gas production histories with Aminian et al Type Curves.

- The program successfully iterates on values of flowing pressure, permeability, and gas in place to obtain a match with type curves.

- The consistency of the computer program has been verified by using gas production histories up to 25%, 50%, and 75% of the gas in place to forecast the remainder of production history.

- Reliable predictions were obtained for F_{NDi}, and *Gi* for the four proposed scenarios considered. The accuracy in the prediction of *Pwf* depends on the amount of data available.

- Excellent gas production forecasts are obtained if 75% of the gas in place of a well is available for history matching.

- If the available production history is approximately 50% of the gas in place, the production rates can be predicted with less than 10% error, up to 84% recovery.

- If the available production history is about 25% of the gas in place, gas production rates up to 78% recovery can be predicted with less than 10% error.

6.2 Recommendations

The following recommendations are suggested from this study:

- To implement a statistical method capable of differentiating between type curves, and production histories with better accuracy when the recovery is about 25% to 50%.

- To implement a more efficient algorithm to obtain a match in a reasonable time when gas-in-place is higher than 20 Bcf, and permeability is higher than 100 md.

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Appendix A

Sample runs using 50 % of the total production history

Case 1.

This case has a production history of 2704 days (7.41 years). The initial gas in place is 11.467 Bcf; the reservoir permeability is 90 md. The well was produced under a constant pressure of 315 psia, with an initial reservoir pressure of 1700 psia. The first 367 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table A.1 Predicted results using 50% of the total production history for case 1.

Parameter	Actual	Matched	Error difference, %
K, md	90	90.06	0.07
Pwf, psia	315	319.75	1.51
Gi, Bcf	11.467	11.484	0.15
Fndi	2.04	2.04	0.00
Xi	5.96	5.87	1.51

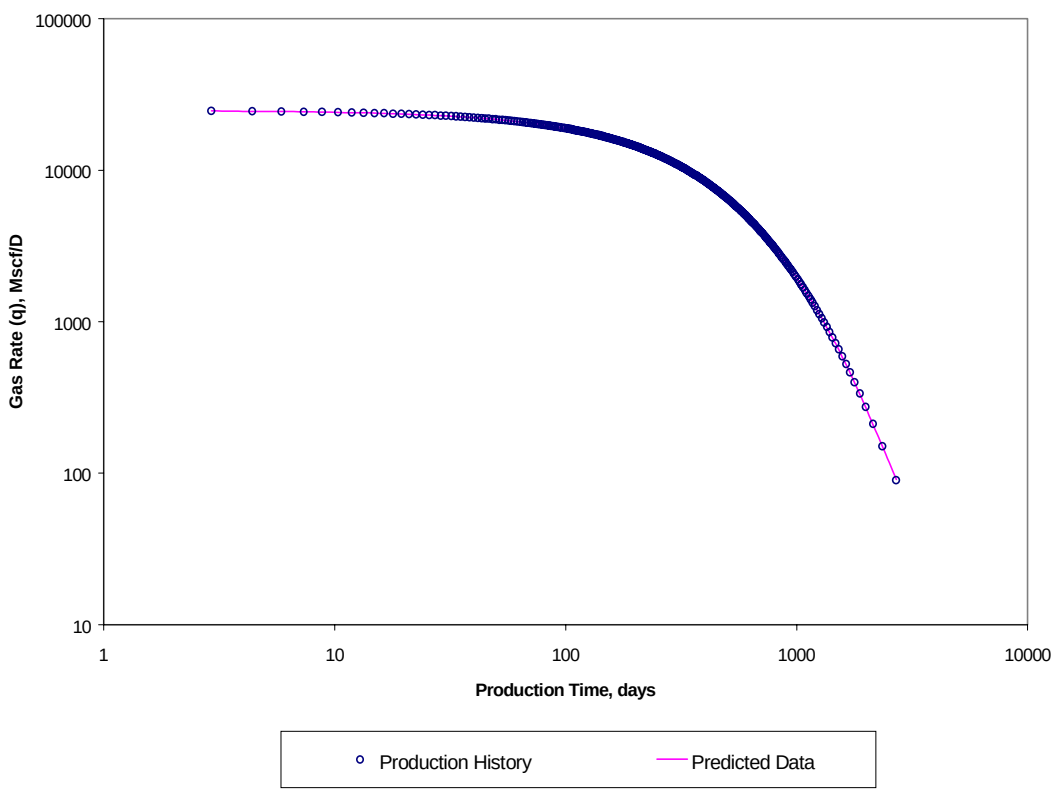

Figure A.1 Graphic verification for predicted gas production. Case 1

Table A.2 Predicted gas flow-rates using 50% of total production history. Case 1

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
367.49	9224.05	9223.00	0.01	50.17
382.74	8860.29	8858.97	0.01	51.37
398.58	8498.27	8496.93	0.02	52.56
415.07	8138.07	8136.51	0.02	53.75
432.28	7779.82	7777.85	0.03	54.94
450.24	7423.57	7421.34	0.03	56.12
469.03	7069.50	7067.17	0.03	57.30
488.74	6717.70	6715.07	0.04	58.48
509.45	6368.31	6365.42	0.05	59.65
531.28	6021.45	6018.15	0.05	60.83
554.34	5677.30	5673.62	0.06	61.99
578.76	5335.99	5332.10	0.07	63.16
604.74	4997.74	4993.42	0.09	64.32
639.68	4579.47	4574.68	0.10	65.76
677.82	4166.65	4161.44	0.12	67.20
728.71	3679.09	3673.32	0.16	68.92
776.36	3279.89	3273.61	0.19	70.35
818.72	2965.56	2958.91	0.22	71.49
865.69	2656.03	2649.03	0.26	72.62
918.34	2351.65	2344.38	0.31	73.75
994.42	1978.92	1971.33	0.38	75.16
1066.21	1687.44	1679.71	0.46	76.28
1151.43	1402.34	1394.63	0.55	77.40
1255.95	1124.09	1116.55	0.67	78.52
1390.29	853.17	846.090	0.83	79.63
1637.20	525.63	519.90	1.09	81.01
1994.81	273.16	269.69	1.27	82.11
2143.82	211.45	208.98	1.17	82.39
2353.53	150.31	149.16	0.77	82.66
2704.14	89.77	90.90	1.26	82.94

Case 2.

This case has a production history of 722.91 days (1,98 years). The initial gas in place is 5.469 Bcf; the reservoir permeability is 75 md. The well was produced under a constant pressure of 300 psia, with an initial reservoir pressure of 3180 psia. The first 77 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table A.3 Predicted results using 50% of the total production history for Case 2.

Parameter	Actual	Matched	Error difference, %
K, md	75	74.97	0.04
Pwf, psia	300	262.02	12.66
Gi, Bcf	5.469	5.435	0.62
Fndi	3.17	3.17	0.00
Xi	12.11	13.93	15.03

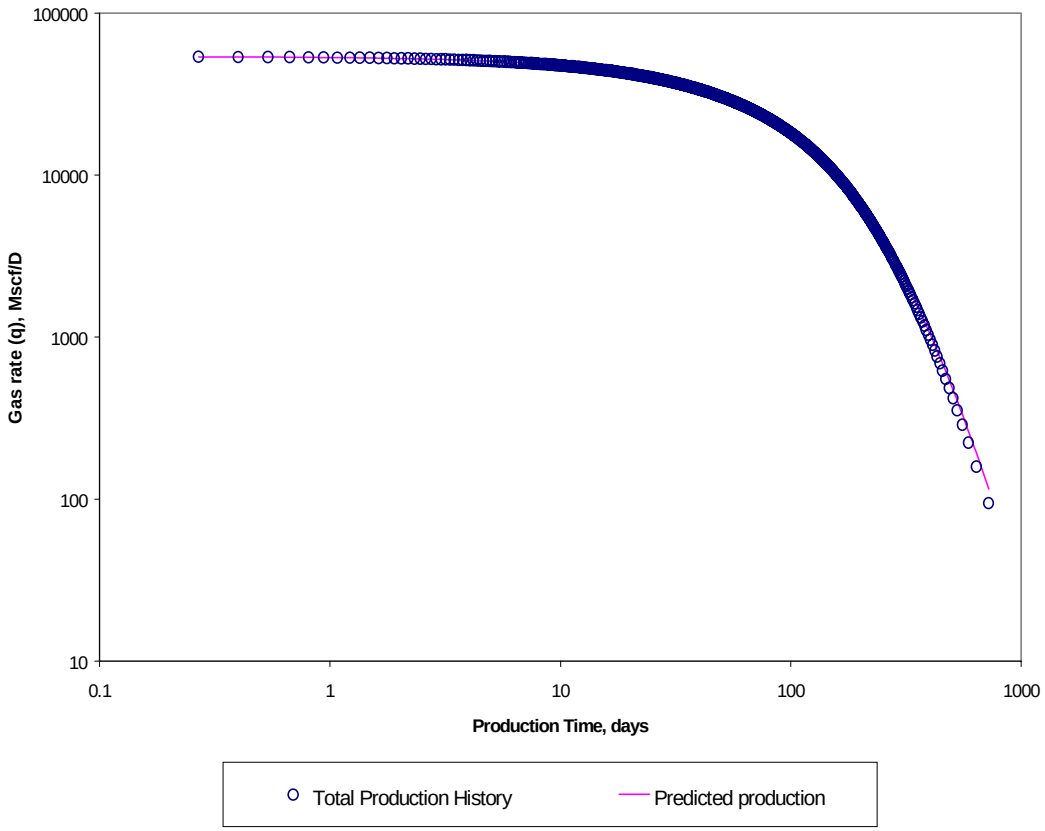

Figure A.2 Graphic verification for predicted gas production. Case 2.

Table A.4 Predicted gas flow-rates using 50% of total production history. Case 2

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
76.85	23021.61	22977.14	0.19	50.01
80.21	22244.27	22199.63	0.20	51.39
83.68	21468.47	21425.47	0.20	52.78
87.28	20694.07	20651.12	0.21	54.16
91.01	19921.33	19878.63	0.21	55.54
94.88	19150.36	19107.90	0.22	56.92
98.89	18381.44	18340.68	0.22	58.29
103.60	17518.79	17478.72	0.23	59.83
109.08	16563.68	16526.65	0.22	61.53
114.27	15707.50	15671.89	0.23	63.06
119.10	14949.18	14916.17	0.22	64.41
124.16	14193.84	14163.05	0.22	65.75
129.46	13441.65	13414.46	0.20	67.09
135.04	12692.84	12668.76	0.19	68.42
140.93	11947.78	11926.62	0.18	69.74
148.77	11022.15	11005.81	0.15	71.38
162.65	9556.03	9547.97	0.08	73.97
170.32	8830.73	8828.48	0.03	75.25
187.57	7398.71	7408.31	0.13	77.79
197.39	6693.33	6708.43	0.23	79.05
220.26	5308.30	5337.26	0.55	81.53
233.87	4630.91	4667.60	0.79	82.75
270.39	3233.40	3286.41	1.64	85.32
322.02	1984.72	2050.59	3.32	87.69
443.92	686.87	750.90	9.32	90.31
470.91	551.50	611.95	10.96	90.60
505.90	418.18	472.59	13.01	90.89
555.45	286.99	333.18	16.10	91.17
590.66	222.22	263.21	18.44	91.32
640.22	158.02	191.39	21.12	91.46
722.91	94.40	115.29	22.13	91.60

Case 3.

This case has a production history of 9203 days (25.2 years). The initial gas in place is 5.164 Bcf; the reservoir permeability is 10 md. The well was produced under a constant pressure of 280 psia, with an initial reservoir pressure of 2000 psia. The first 753 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table A.5 Predicted results using 50% of the total production history. Case 3

Parameter	Actual	Matched	Error difference, %
K, md	10	10.03	0.30
Pwf, psia	280	304.82	8.86
Gi, Bcf	5.164	5.182	0.35
Fndi	1.29	1.29	0.00
Xi	8.75	8.01	8.46

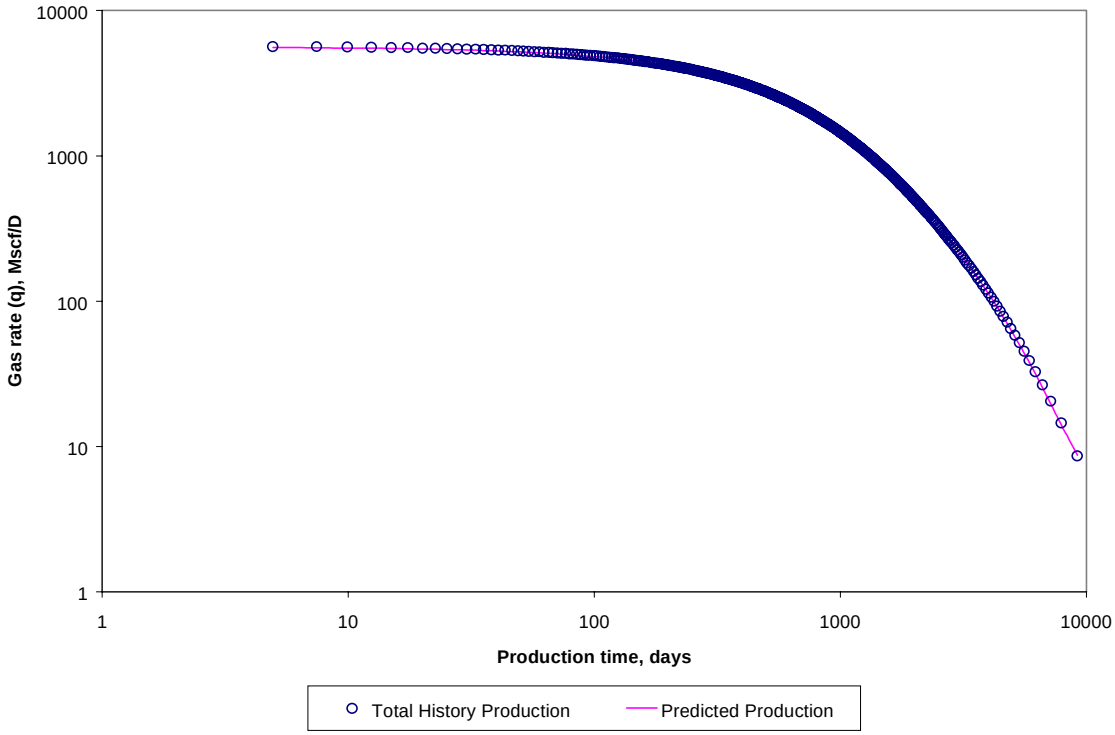

Figure A.3 Graphic verification for predicted gas production. Case 3

Table A.6 Predicted gas flow-rates using 50% of the total production history. Case 3

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
752.55	1977.00	1966.58	0.53	50.06
787.64	1890.63	1881.40	0.49	51.37
824.16	1805.46	1797.39	0.45	52.67
862.24	1721.52	1714.56	0.40	53.97
901.99	1638.86	1632.98	0.36	55.26
943.55	1557.51	1552.62	0.31	56.54
987.09	1477.50	1473.55	0.27	57.81
1032.75	1398.89	1395.83	0.22	59.08
1080.77	1321.71	1319.43	0.17	60.34
1131.34	1246.00	1244.47	0.12	61.59
1195.75	1157.15	1156.45	0.06	63.08
1264.75	1070.55	1070.53	0.00	64.56
1338.94	986.27	986.84	0.06	66.03
1419.05	904.40	905.44	0.11	67.49
1505.99	825.00	826.41	0.17	68.94
1600.84	748.15	749.83	0.22	70.38
1705.00	673.92	675.76	0.27	71.81
1820.21	602.39	604.31	0.32	73.22
1948.74	533.64	535.47	0.34	74.63
2093.42	467.75	469.40	0.35	76.02
2258.30	404.77	406.17	0.35	77.40
2415.07	354.57	355.70	0.32	78.54
2594.20	306.50	307.29	0.26	79.68
2801.98	260.59	260.99	0.15	80.81
3102.56	208.40	208.31	0.04	82.15
3413.60	167.38	166.88	0.30	83.26
3808.24	128.64	127.73	0.71	84.36
4339.15	92.22	90.96	1.37	85.45
5130.99	58.15	56.80	2.31	86.54
6630.13	26.47	25.52	3.59	87.62
7169.36	20.42	19.68	3.60	87.84
7928.88	14.47	14.05	2.91	88.05
9203.61	8.61	8.71	1.21	88.26

Case 4.

This case has a production history of 13,707 days (37.55 years). The initial gas in place is 0.485 Bcf; the reservoir permeability is 0.38 md. The well was produced under a constant pressure of 545 psia, with an initial reservoir pressure of 1800 psia. The first 2,167 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table A.7 Predicted results using 50% of the total production history. Case 4

Parameter	Actual	Matched	Error difference, %
K, md	0.38	0.37	2.63
Pwf, psia	545	542.54	0.45
Gi, Bcf	0.485	0.471	2.89
Fndi	1.04	1.04	0.00
Xi	3.65	3.67	0.55

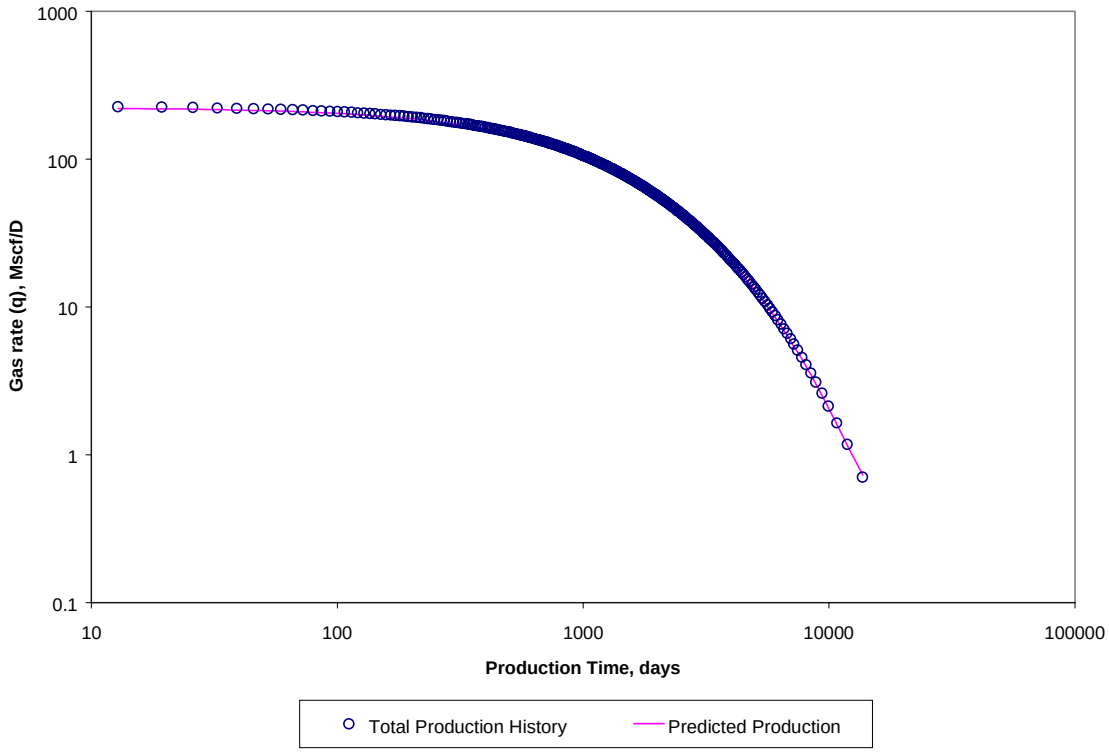

Figure A.4 Graphic verification for predicted gas production. Case 4.

Table A.8 Predicted gas flow-rates using 50% of the total production history. Case 4.

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
2167.33	51.50	49.96	2.98	50.04
2250.22	49.17	47.70	2.98	50.89
2336.99	46.88	45.48	3.00	51.75
2459.13	43.87	42.55	3.00	52.88
2556.12	41.66	40.40	3.02	53.72
2658.12	39.48	38.28	3.04	54.57
2802.85	36.62	35.51	3.04	55.69
2918.86	34.51	33.46	3.04	56.53
3041.72	32.44	31.45	3.05	57.37
3172.23	30.41	29.48	3.07	58.21
3311.53	28.41	27.53	3.09	59.04
3460.57	26.44	25.62	3.09	59.87
3676.92	23.87	23.13	3.10	60.98
3854.58	21.98	21.30	3.09	61.81
4047.64	20.13	19.50	3.11	62.63
4333.78	17.72	17.16	3.14	63.73
4574.60	15.95	15.45	3.14	64.55
4843.09	14.21	13.77	3.10	65.37
5145.96	12.52	12.12	3.16	66.18
5619.97	10.31	9.98	3.16	67.26
6046.99	8.69	8.42	3.10	68.07
6561.81	7.11	6.89	3.05	68.88
7207.40	5.57	5.40	3.03	69.69
8068.08	4.07	3.95	3.06	70.49
9960.61	2.12	2.06	2.62	71.56
10749.12	1.64	1.61	2.04	71.83
11855.35	1.17	1.16	1.07	72.09
13706.81	0.70	0.73	3.86	72.36

Case 5.

This case has a production history of 11,081 days (30.35 years). The initial gas in place is 0.398 Bcf; the reservoir permeability is 0.50 md. The well was produced under a constant pressure of 400 psia, with an initial reservoir pressure of 2100 psia. The first 1,034 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table A.9 Predicted results using 50% of the total production history. Case 5.

Parameter	Actual	Matched	Error difference, %
K, md	0.5	0.51	2.00
Pwf, psia	400	501.86	25.47
Gi, Bcf	0.398	0.41	3.02
Fndi	1.05	1.05	0.00
Xi	5.96	4.7	21.14

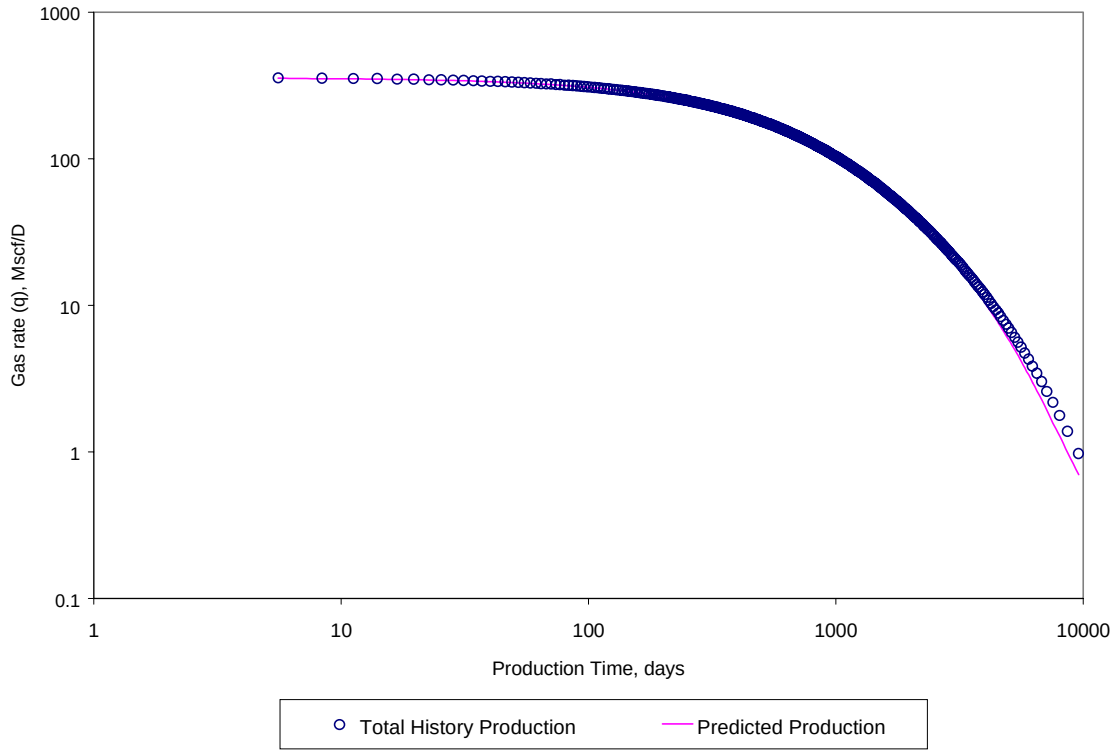

Figure A.5 Graphic verification for predicted gas production. Case 5.

Table A.10 Predicted gas flow-rates using 50% of the total production history. Case 5.

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
1034.10	99.81	98.66	1.16	50.02
1074.44	95.86	94.68	1.23	51.01
1116.37	91.96	90.77	1.30	51.99
1159.97	88.13	86.91	1.38	52.97
1205.42	84.36	83.12	1.47	53.95
1264.94	79.73	78.47	1.58	55.17
1327.79	75.21	73.91	1.72	56.39
1394.28	70.78	69.46	1.87	57.60
1464.75	66.45	65.11	2.02	58.80
1539.66	62.23	60.86	2.21	60.01
1603.10	58.93	57.53	2.37	60.97
1669.96	55.69	54.27	2.55	61.92
1740.59	52.52	51.08	2.74	62.87
1815.42	49.41	47.95	2.95	63.82
1894.70	46.38	44.90	3.19	64.77
2001.01	42.68	41.19	3.50	65.95
2116.32	39.09	37.58	3.87	67.12
2216.06	36.29	34.77	4.19	68.05
2323.35	33.57	32.04	4.57	68.99
2439.23	30.92	29.38	4.99	69.91
2565.01	28.33	26.79	5.45	70.84
2702.18	25.82	24.28	5.98	71.76
2852.78	23.38	21.84	6.58	72.68
3019.29	21.01	19.48	7.27	73.59
3204.83	18.72	17.20	8.09	74.51
3413.77	16.50	15.00	9.06	75.41
3589.16	14.88	13.41	9.85	76.09
3854.43	12.78	11.36	11.10	76.99
4165.87	10.76	9.41	12.59	77.89
4540.55	8.81	7.54	14.41	78.79
5007.46	6.94	5.77	16.82	79.68
5620.47	5.14	4.12	19.86	80.57
6500.64	3.42	2.60	23.93	81.45
6793.48	3.00	2.26	24.74	81.67
7133.30	2.58	1.91	25.78	81.89
7536.83	2.17	1.57	27.74	82.11
8032.05	1.77	1.28	27.87	82.33
8672.40	1.37	0.98	28.83	82.55
9573.20	0.97	0.70	27.50	82.77

Appendix B

Sample runs using 25% of the total production history

Case 1.

This case has a production history of 2704 days (7.41 years). The initial gas in place is 11.467 Bcf; the reservoir permeability is 90 md. The well was produced under a constant pressure of 315 psia, with an initial reservoir pressure of 1700 psia. The first 140 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table B.1 Predicted results for using 25% of the total production history. Case 1

Parameter	Actual	Matched	Error difference, %
K, md	90	90.06	0.07
Pwf, psia	315	321.83	2.17
Gi, Bcf	11.467	11.484	0.15
Fndi	2.04	2.04	0.00
Xi	5.96	5.83	2.18

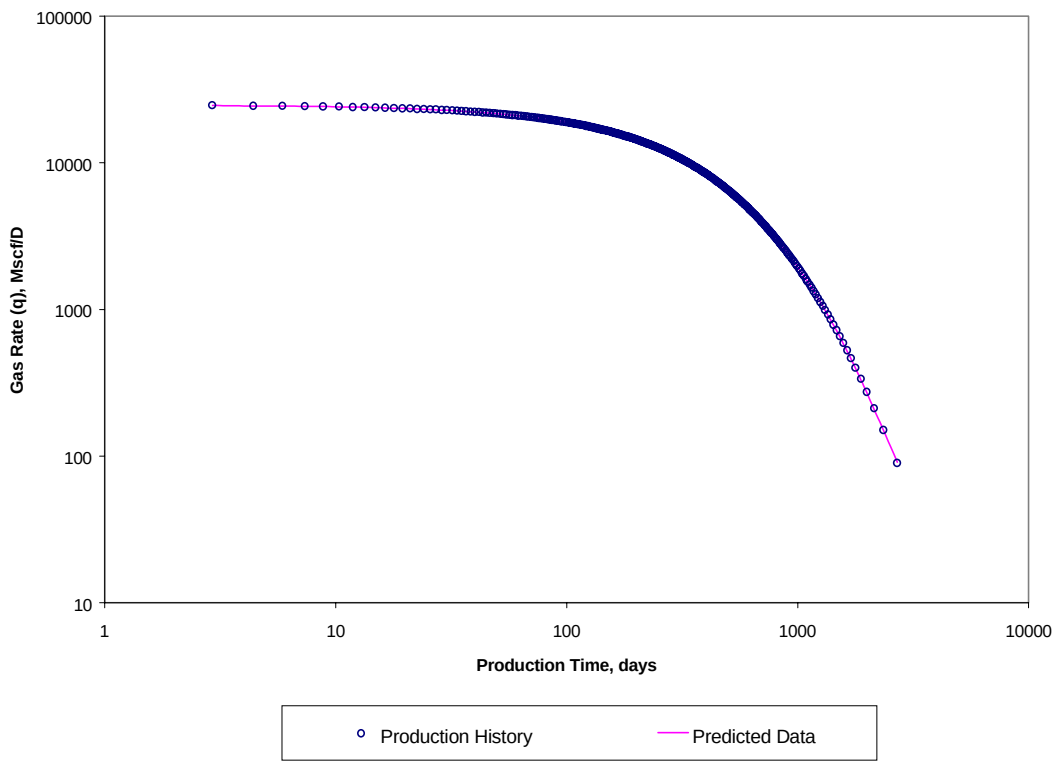

Figure B.1 Graphic verification for predicted gas production. Case 1

Table B.2 Predicted gas flow-rates using 25% of total production history. Case 1

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi Produced
139.90	16954.52	16946.87	0.05	25.09
152.78	16375.86	16368.30	0.05	26.95
166.09	15798.75	15791.4	0.05	28.82
179.87	15223.32	15216.16	0.05	30.67
194.15	14649.58	14642.36	0.05	32.53
208.96	14077.88	14070.75	0.05	34.38
224.34	13508.06	13501.25	0.05	36.22
240.35	12940.47	12933.55	0.05	38.06
257.03	12375.18	12368.24	0.06	39.89
274.44	11812.35	11805.16	0.06	41.72
295.77	11159.03	11151.72	0.07	43.85
318.28	10509.68	10502.22	0.07	45.97
342.13	9864.55	9856.98	0.08	48.07
363.77	9315.22	9307.40	0.08	49.88
386.64	8769.60	8761.60	0.09	51.67
410.89	8227.94	8219.54	0.10	53.46
436.69	7690.56	7681.92	0.11	55.24
464.25	7157.82	7148.83	0.13	57.01
493.83	6630.13	6620.59	0.14	58.78
531.28	6021.45	6011.47	0.17	60.83
566.37	5506.28	5495.85	0.19	62.57
604.74	4997.74	4986.78	0.22	64.32
647.03	4496.46	4485.04	0.25	66.05
694.11	4003.15	3991.18	0.30	67.78
747.13	3518.60	3506.15	0.35	69.49
807.73	3043.70	3030.73	0.43	71.20
878.27	2579.44	2566.08	0.52	72.91
962.41	2126.94	2113.33	0.64	74.60
1066.21	1687.44	1673.83	0.81	76.28
1200.79	1262.33	1249.13	1.05	77.96
1390.29	853.17	840.94	1.43	79.63
2353.53	150.31	148.38	1.28	82.66
2704.14	89.77	92.65	3.20	82.94

Case 2.

This case has a production history of 722.91 days (1,98 years). The initial gas in place is 5.469 Bcf; the reservoir permeability is 75 md. The well was produced under a constant pressure of 300 psia, with an initial reservoir pressure of 3180 psia. The first 31 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table B.3 Predicted results using 25% of the total production history. Case 2.

Parameter	Actual	Matched	Error difference, %
K, md	75	75.49	0.65
Pwf, psia	300	401.82	33.94
Gi, Bcf	5.469	5.509	0.73
Fndi	3.17	3.16	0.32
Xi	12.11	8.94	26.18

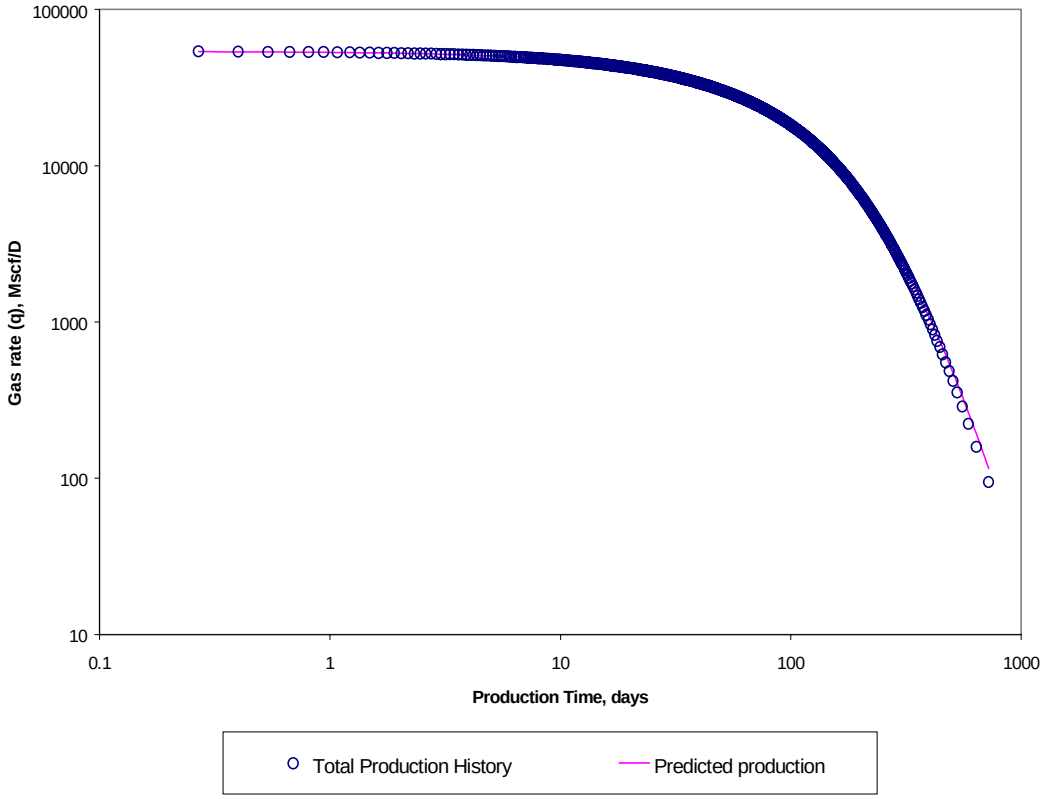

Figure B.2 Graphic verification for predicted gas production. Case 2.

Table B.4 Predicted gas-flow rates using 25% of total production history. Case 2.

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
30.55	37414.61	37403.45	0.03	25.03
33.46	36239.80	36224.59	0.04	26.99
36.50	35063.66	35043.59	0.06	28.97
39.95	33788.88	33761.03	0.08	31.13
43.56	32513.31	32479.54	0.10	33.32
47.34	31237.66	31199.19	0.12	35.52
51.31	29962.41	29917.48	0.15	37.74
55.15	28785.60	28734.45	0.18	39.79
59.17	27609.96	27551.68	0.21	41.86
63.38	26435.60	26369.22	0.25	43.94
67.79	25262.99	25188.79	0.29	46.02
72.41	24092.46	24011.58	0.34	48.10
77.26	22924.48	22836.24	0.38	50.18
82.37	21759.27	21661.24	0.45	52.26
88.20	20500.82	20394.51	0.52	54.51
94.38	19246.66	19131.23	0.60	56.75
100.44	18093.56	17966.94	0.70	58.81
107.41	16849.84	16712.11	0.82	61.02
114.27	15707.50	15559.89	0.94	63.06
121.60	14571.10	14412.75	1.09	65.08
129.46	13441.65	13272.47	1.26	67.09
137.95	12319.88	12137.53	1.48	69.08
147.16	11206.78	11011.62	1.74	71.05
157.23	10103.45	9895.16	2.06	73.00
168.35	9011.53	8789.34	2.47	74.93
180.77	7932.62	7695.87	2.98	76.84
196.11	6781.08	6528.22	3.73	78.89
214.06	5651.02	5382.27	4.76	80.91
233.87	4630.91	4349.53	6.08	82.75
258.29	3637.81	3346.93	8.00	84.57
278.37	2993.74	2701.02	9.78	85.77
317.97	2060.46	1776.74	13.77	87.54
590.66	222.22	144.51	34.97	91.32

Case 3

This case has a production history of 9,203 days (25.2 years). The initial gas in place is 5.154 Bcf; the reservoir permeability is 10 md. The well was produced under a constant pressure of 280 psia, with an initial reservoir pressure of 2,000 psia. The first 281 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table B.5 Predicted results using 25% of the total production history. Case 3.

Parameter	Actual	Matched	Error difference, %
K, md	10	10.76	7.60
Pwf, psia	280	317.8	13.50
Gi, Bcf	5.154	5.398	4.73
Fndi	1.29	1.31	1.55
Xi	8.75	7.66	12.46

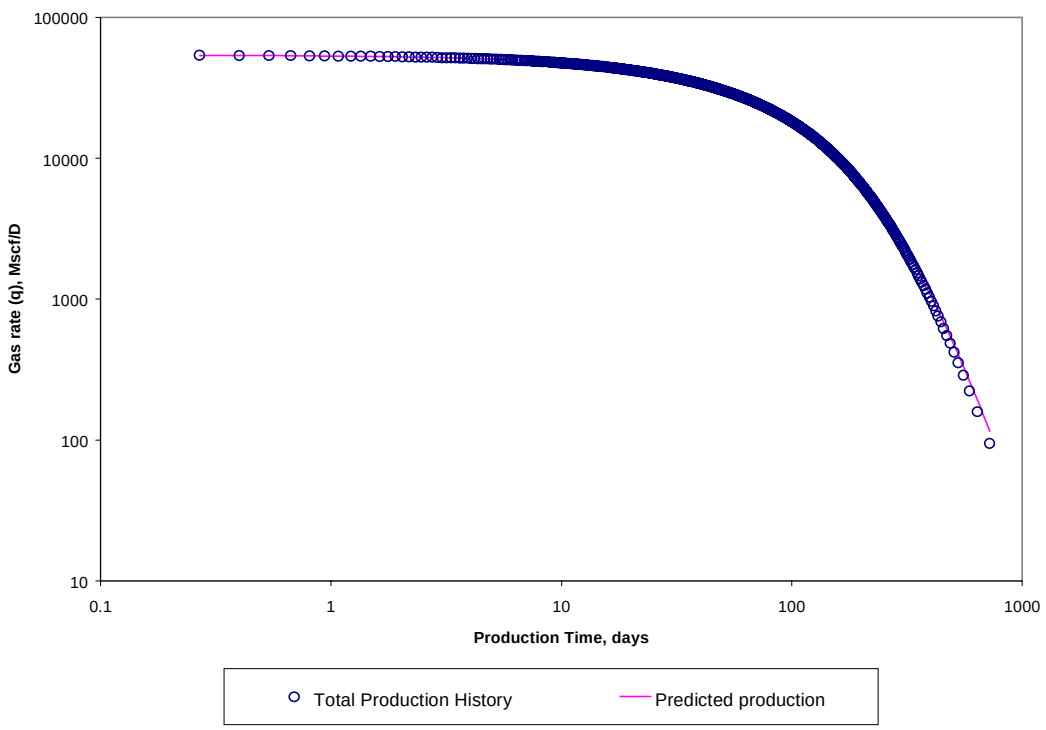

Figure B.3 Graphic verification for predicted gas production. Case 3.

Table B.6 Predicted gas flow-rates using 25% of total production history. Case 3.

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
281.24	3738.96	3935.40	5.25	25.20
312.73	3575.19	3760.64	5.19	27.43
345.60	3413.06	3587.78	5.12	29.65
379.97	3252.68	3416.81	5.05	31.87
415.94	3094.17	3247.90	4.97	34.07
453.64	2937.64	3081.14	4.88	36.27
498.29	2764.06	2896.27	4.78	38.73
540.13	2612.13	2734.62	4.69	40.90
589.89	2444.04	2555.77	4.57	43.33
636.73	2297.28	2399.75	4.46	45.48
686.29	2153.19	2246.65	4.34	47.61
738.91	2011.87	2096.61	4.21	49.73
794.82	1873.50	1949.81	4.07	51.82
854.48	1738.21	1806.42	3.92	53.90
918.38	1606.16	1666.55	3.76	55.96
987.09	1477.50	1530.40	3.58	58.01
1061.27	1352.41	1398.20	3.39	60.03
1141.78	1231.03	1270.07	3.17	62.03
1229.65	1113.56	1146.22	2.93	64.02
1338.94	986.27	1012.22	2.63	66.22
1447.22	877.65	898.07	2.33	68.16
1568.28	773.47	788.80	1.98	70.08
1705.00	673.92	684.58	1.58	71.98
1861.51	579.16	585.60	1.11	73.86
2068.03	478.53	480.75	0.46	75.95
2288.09	394.56	393.60	0.24	77.79
2556.32	315.94	312.24	1.17	79.60
2895.04	242.84	237.08	2.37	81.39
3345.85	175.4	168.20	4.10	83.16
3999.80	113.8	106.09	6.78	84.92
4768.32	71.50	64.44	9.87	86.22
7169.36	20.42	17.19	15.79	87.93
7928.88	14.47	12.29	15.08	88.15
9203.61	8.61	7.21	16.27	88.36

Case 4.

This case has a production history of 13,707 days (37.55 years). The initial gas in place is 0.485 Bcf; the reservoir permeability is 0.38 md. The well was produced under a constant pressure of 545 psia, with an initial reservoir pressure of 1800 psia. The first 709 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table B.7 Predicted results using 25% of the total production history. Case 4.

Parameter	Actual	Matched	Error difference, %
K, md	0.38	0.37	2.63
Pwf, psia	545	576.1	5.71
Gi, Bcf	0.485	0.478	1.44
Fndi	1.04	1.04	0.00
Xi	3.65	3.44	5.75

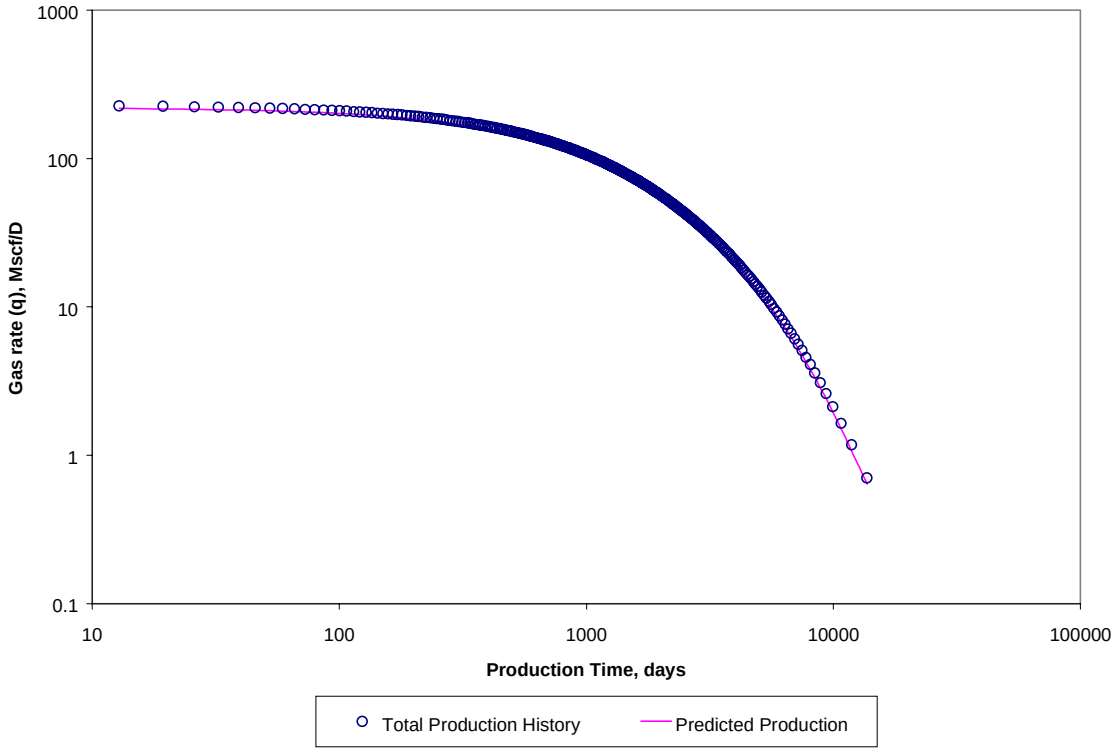

Figure B.4 Graphic verification for predicted gas production. Case 4

Table B.8 Predicted gas flow rates using 50% of total production history. Case 4.

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
709.13	130.03	125.66	3.36	25.20
766.10	124.78	120.61	3.34	26.69
825.42	119.61	115.63	3.33	28.18
887.22	114.51	110.72	3.31	29.66
951.68	109.48	105.87	3.29	31.14
1019.00	104.53	101.10	3.28	32.62
1103.92	98.69	95.47	3.26	34.39
1193.70	92.97	89.95	3.25	36.15
1288.83	87.36	84.54	3.23	37.91
1372.62	82.78	80.11	3.23	39.37
1460.91	78.28	75.76	3.22	40.83
1554.13	73.86	71.48	3.22	42.28
1652.76	69.53	67.29	3.22	43.73
1779.00	64.44	62.37	3.22	45.46
1891.63	60.30	58.35	3.23	46.90
2036.83	55.45	53.65	3.25	48.61
2194.56	50.72	49.06	3.27	50.32
2366.83	46.12	44.60	3.29	52.03
2523.22	42.39	40.98	3.33	53.44
2693.35	38.76	37.44	3.40	54.85
2879.32	35.21	34.00	3.44	56.25
3084.30	31.76	30.64	3.52	57.65
3311.53	28.41	27.38	3.63	59.04
3566.06	25.15	24.21	3.75	60.43
3854.58	21.98	21.13	3.87	61.81
4186.17	18.92	18.15	4.08	63.18
4574.60	15.95	15.26	4.31	64.55
5040.69	13.08	12.48	4.62	65.91
5619.97	10.31	9.79	5.05	67.26
6378.27	7.64	7.21	5.65	68.61
7748.99	4.56	4.27	6.45	70.22
9960.61	2.12	1.95	7.79	71.56
13706.81	0.70	0.64	8.15	72.36

Case 5

This case has a production history of 11,081 days (30.35 years). The initial gas in place is 0.398 Bcf; the reservoir permeability is 0.50 md. The well was produced under a constant pressure of 400 psia, with an initial reservoir pressure of 2100 psia. The first 359 days were used for history matching, and the remaining data were used for comparison with predicted rates.

Table B.9 Predicted results using 25% of the total production history. Case 5.

Parameter	Actual	Matched	Error difference, %
K, md	0.5	0.53	6.00
Pwf, psia	400	503.28	25.82
Gi, Bcf	0.398	0.418	5.03
Fndi	1.05	1.05	0.00
Xi	5.96	4.68	5.75

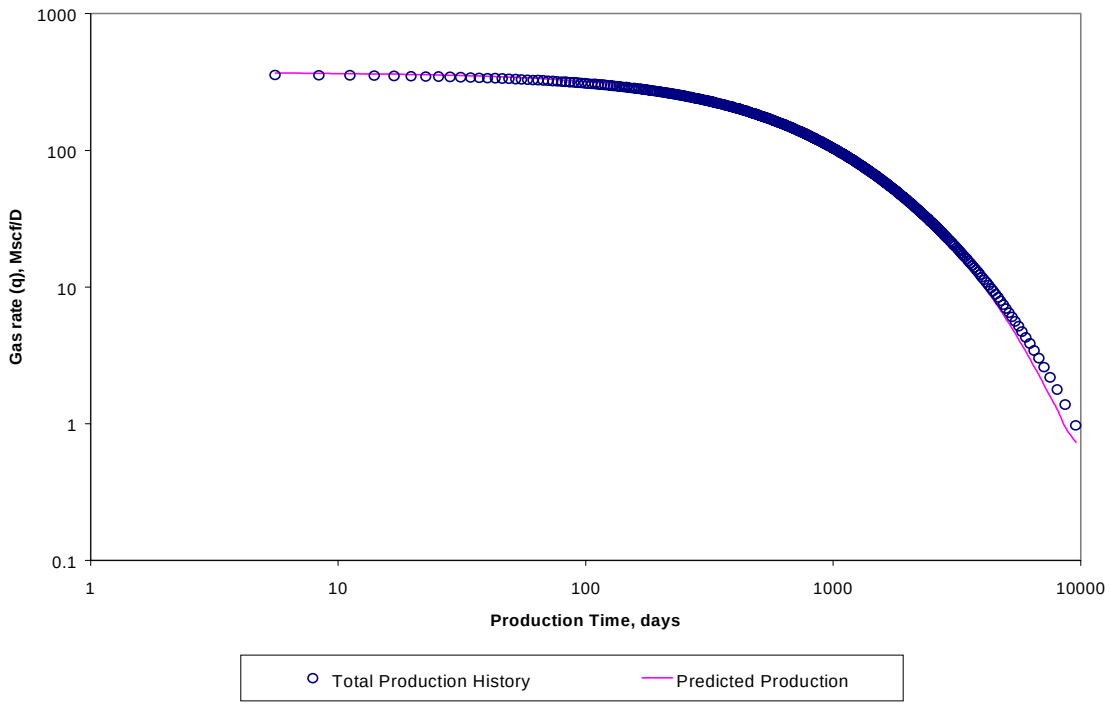

Figure B.5 Graphic verification for predicted gas production. Case 5.

Table B.10 Predicted gas flow-rates using 25% of the total production history. Case 5

Time, days	Actual q, Mscf/D	Predicted q, Mscf/D	Error, %	% of Gi produced
359.42	215.28	221.42	2.85	25.06
393.27	206.11	211.87	2.80	26.85
428.65	197.08	202.46	2.73	28.63
465.62	188.19	193.21	2.67	30.42
504.33	179.45	184.11	2.6	32.20
544.90	170.85	175.16	2.52	33.98
587.48	162.41	166.37	2.44	35.75
632.21	154.13	157.75	2.35	37.52
679.28	146.00	149.29	2.25	39.29
728.90	138.04	141.01	2.15	41.05
781.27	130.25	132.90	2.04	42.81
836.68	122.62	124.97	1.92	44.56
895.43	115.17	117.22	1.78	46.30
957.81	107.90	109.66	1.63	48.04
1024.25	100.81	102.29	1.47	49.78
1095.20	93.90	95.11	1.29	51.50
1171.18	87.18	88.12	1.08	53.22
1252.78	80.65	81.34	0.86	54.93
1340.79	74.31	74.76	0.61	56.63
1436.06	68.17	68.39	0.33	58.32
1539.66	62.23	62.23	0.00	60.01
1652.91	56.49	56.28	0.37	61.68
1777.52	50.96	50.55	0.81	63.35
1915.29	45.63	45.04	1.28	65.00
2069.04	40.51	39.76	1.86	66.65
2242.12	35.61	34.70	2.55	68.29
2439.23	30.92	29.88	3.38	69.91
2666.73	26.44	25.29	4.35	71.53
2933.85	22.19	20.95	5.60	73.14
3254.70	18.16	16.86	7.18	74.73
3651.82	14.35	13.03	9.22	76.32
4165.87	10.76	9.48	11.92	77.89
4879.80	7.40	6.23	15.80	79.46
6014.27	4.27	3.35	21.63	81.01
6500.64	3.42	2.59	24.13	81.45
7133.3	2.58	1.90	26.34	81.89
8032.05	1.77	1.27	28.19	82.33
9573.20	0.97	0.73	25.09	82.77

Appendix C

Code of the computer program

This portion of code to calculate gas properties

Private Sub CmdProperties_Click()

```
Const A1 = 0.3265:    Const A2 = -1.07:      Const A3 = -0.5339:    Const A4 = 0.01569
Const A5 = -0.05165: Const A6 = 0.5475:   Const A7 = -0.7361:    Const A8 = 0.1844
Const A9 = 0.1056:   Const A10 = 0.6134:  Const A11 = 0.721:
Dim N1 As Single, counter As Integer, i As Integer
Dim Ppc As Single, Tpc As Single, Tpr As Single, Ppr As Single
Dim D1 As Single, D As Single
Dim j1 As Single, j2 As Single, j3 As Single, j4 As Single, z As Single
Dim G1 As Single, G2 As Single, G3 As Single, G4 As Single, Cpr As Single
Dim compressibility As Single
Dim Ma As Single, E As Single, B1 As Single, C As Single, Density As Single
Dim Viscosity As Single
Dim tmp1 As Single, tmp2 As Single, tmp3 As Single, tmp4 As Single, Tmp As Single
Dim PseudoPressure As Single, Pi As Single, DeltaPressure As Single
Dim Gas_Properties As String, PathName As String


Pi = Val(TxtPi.Text)
DeltaPressure = Val(TxtDPressure.Text)
N1 = Pi / DeltaPressure

PseudoPressure = 0
Tmp = 0

counter = 1

Ppc = 709.604 - 58.718 * Val(TxtGravity.Text)
Tpc = 170.491 + 307.344 * Val(TxtGravity.Text)
Tpr = (Val(TxtTemp.Text) + 460) / Tpc

'*****************************************************************************************************************
On Error GoTo DriveError

PathName = FrmMain!drvDrive.Drive
Gas_Properties = PathName + "\" + FrmMain!TxtFile1.Text

Open Gas_Properties For Output As #1

ReDim Pressure(N1)
ReDim Zf(N1)
ReDim Compres(N1)
ReDim Vis(N1)
ReDim PseudoP(N1)

For i = Val(TxtDPressure.Text) To Val(TxtPi.Text) Step Val(TxtDPressure.Text)

GrdGasProperties.Col = 0
GrdGasProperties.Row = counter
GrdGasProperties.Text = counter

GrdGasProperties.Col = 1
GrdGasProperties.Row = counter
GrdGasProperties.Text = i

Pressure(counter) = i
Ppr = i / Ppc
```

```
' ************************************************************************************************************
' Subroutine to Calculate Z-factor


D1 = 0.27 * (Ppr / Tpr)
D = 0
Do While (Abs(D1 - D) > 0.0001)
D = D1
j1 = 1 + (A1 + A2 / Tpr + A3 / Tpr ^ 3 + A4 / Tpr ^ 4 + A5 / Tpr ^ 5) * D
j2 = (A6 + A7 / Tpr + A8 / Tpr ^ 2) * D ^ 2
j3 = A9 * (A7 / Tpr + A8 / Tpr ^ 2) * D ^ 5
j4 = A10 * (1 + A11 * D ^ 2) * (D ^ 2 / Tpr ^ 3) * Exp(-A11 * D ^ 2)

z = j1 + j2 - j3 + j4

D1 = 0.27 * (Ppr / (z * Tpr))
Loop

GrdGasProperties.Col = 2
GrdGasProperties.Row = counter
GrdGasProperties.Text = Format(z, "0.00000")

Zf(counter) = GrdGasProperties.Text

'************************************************************************************************************

' Subroutine to calculate Gas Compressibility

G1 = A1 + A2 / Tpr + A3 / Tpr ^ 3 + A4 / Tpr ^ 4 + A5 / Tpr ^ 5
G2 = 2 * D * (A6 + A7 / Tpr + A8 / Tpr ^ 2) - 5 * D ^ 4 * A9 * (A7 / Tpr + A8 / Tpr ^ 2)
G3 = 2 * A10 * D / Tpr ^ 3 * (1 + A11 * D ^ 2 - A11 ^ 2 * D ^ 4) * Exp(-A11 * D ^ 2)
G4 = G1 + G2 + G3
Cpr = 1 / Ppr - 0.27 / (z ^ 2 * Tpr) * (G4 / (1 + (D / z) * G4))
compressibility = Cpr / Ppc

GrdGasProperties.Col = 3
GrdGasProperties.Row = counter
GrdGasProperties.Text = Format(compressibility, "0.0000000")
Compres(counter) = GrdGasProperties.Text



'************************************************************************************************************
'Subroutine for Gas Viscosity

Ma = 29 * Val(TxtGravity.Text)
E = (9.379 + 0.01607 * Ma) * (Val(TxtTemp.Text) + 460) ^ 1.5 / (209.2 + 19.26 * Ma +
(Val(TxtTemp.Text) + 460))
B1 = 3.448 + 986.4 / (Val(TxtTemp) + 460) + 0.01009 * Ma
C = 2.447 - 0.2224 * B1
Density = 2.703 * Val(TxtGravity.Text) * i / (z * (460 + Val(TxtTemp.Text)))
Density = Density * 0.016018 'Density conversion to g/cc
Viscosity = E * Exp(B1 * Density ^ C) * 10 ^ -4

GrdGasProperties.Col = 4
GrdGasProperties.Row = counter
GrdGasProperties.Text = Format(Viscosity, "0.000000")
Vis(counter) = GrdGasProperties.Text
```

```
'*****************************************************************************************************
```

'Subroutine for pseudopressure calculations

```
tmp1 = 2 * i / (Viscosity * z)
tmp2 = (tmp1 + Tmp) / 2
tmp3 = tmp2 * Val(TxtDPressure.Text)
tmp4 = tmp3 + PseudoPressure
Tmp = tmp1
PseudoPressure = tmp4

GrdGasProperties.Col = 5
GrdGasProperties.Row = counter
GrdGasProperties.Text = Format(PseudoPressure, "0.00")
PseudoP(counter) = GrdGasProperties.Text

Print #1, Pressure(counter), Zf(counter), Compres(counter), Vis(counter), PseudoP(counter)

counter = counter + 1

Next i

DriveError:
FrmMain.ChangeDrive

Close #1

End Sub
```

The following portion of the code is to calculate a single Type curve

Private Sub CmdGetTypeCurve_Click()

```
Dim PathName As String
Dim Gravity As Single, Temp As Single, Permeability As Single, Porosity As Single
Dim  Skin As Single, Area As Single, CA As Single, h As Single, Rw As Single
Dim Sg As Single, Pi As Single
Dim DeltaPressure As Single, Pwf As Single, MaxPi As Single, N1 As Single
Dim CumulativeTimeyears As Single, CumGPSCF As Single
Dim Dt() As Single, DimDGp() As Single, counter As Integer
Dim Zi As Single, Qi As Single, low As Single, TypeCurve_Results As String
Dim TypeCurveSteps As Single
Dim x1 As Single, x2 As Single, x3 As Single, y1 As Single, y2 As Single
Dim R1 As Single, R2 As Single, NUMINTEGER As Integer, Zwf As Single, MPwf As Single
Dim ViscWF As Single, R As Single, Pnow As Single, Znow As Single, Cnow As Single
Dim ViscR As Single, MPR As Single, ZMaxP As Single, ViscAvg As Single
Dim DeltaMP As Single
Dim Re As Single, Xi As Single, Term As Single, A As Single, Beta As Single, B As Single
Dim MQ As Single
Dim Q As Single, Qnow As Single, Qinitial As Single, Fndi As Single, Qavg As Single
Dim Bgi As Single
Dim Bgf As Single, Gi As Single, iGp As Single, GpScf As Single, GpMcf As Single
Dim Timedays As Single, Timeyears As Single, CumulativeTimeDays As Single
Dim Dq() As Single, DGp() As Single
Dim DeltaPseudopressure As Single, ADeliverability As Single, BDeliverability As Single
Dim Flowrate As Single
Dim i As Integer, Columns As Integer, Rows As Integer
```

```
If Val(TxtPwf.Text) > Val(TxtPi.Text) Then
   MsgBox " Flowing pressure should be smaller than Initial pressure !!", vbExclamation
   Exit Sub
End If

Gravity = Val(TxtGravity.Text)
Temp = Val(TxtTemp.Text)
Permeability = Val(TxtK.Text)
Porosity = Val(TxtPorosity.Text)
Skin = Val(TxtSkin.Text)
Area = Val(TxtArea.Text)
CA = Val(TxtCA.Text)
h = Val(Txth.Text)
Rw = Val(Txtrw.Text)
Sg = Val(TxtSg.Text)
Pi = Val(TxtPi.Text)
DeltaPressure = Val(TxtDPressure.Text)
Pwf = Val(TxtPwf.Text)
MaxPi = Pi

N1 = Pi / DeltaPressure

ReDim Dq(N1)
ReDim DGp(N1)
ReDim Dt(N1)

CumulativeTimeyears = 0
CumGPSCF = 0
Dt(counter) = 0
DGp(counter) = 0
Dq(counter) = 0
counter = -1


Zi = Zf(1)
Qi = 0
low = Pwf

' Output file for results

PathName = FrmMain!drvDrive1.Drive
TypeCurve_Results = PathName + "\" + FrmMain!TxtFile2.Text
Open TypeCurve_Results For Output As #2

'Print #2, "Pressure"; ","; "CumTimeDays"; ","; "Qavg"; ","; "CumGP"; ","; "td"; ","; "Qd"; ","; "GPd"
'Print #2, ""


TypeCurveSteps = (Pi - Pwf) / DeltaPressure
R1 = Pi / DeltaPressure
R2 = Pwf / DeltaPressure


'Checking properties for Pwf

R2 = Pwf / DeltaPressure
NUMINTEGER = Int(R2)
If R2 <> NUMINTEGER Then
```

```
Zwf = PwfPROPINTERPOLATED(R2, NUMINTEGER, (NUMINTEGER + 1), Zf(NUMINTEGER), Zf(NUMINTEGER + 1))
MPwf = PwfPROPINTERPOLATED(R2, NUMINTEGER, (NUMINTEGER + 1), PseudoP(NUMINTEGER), PseudoP(NUMINTEGER + 1))
ViscWF = PwfPROPINTERPOLATED(R2, NUMINTEGER, (NUMINTEGER + 1), Vis(NUMINTEGER), Vis(NUMINTEGER + 1))
Else
Zwf = Zf(R2)
MPwf = PseudoP(R2)
ViscWF = Vis(R2)
End If


For i = 0 To 5000

counter = counter + 1
Pnow = MaxPi - (i * DeltaPressure)

GrdDimensionlessTerms.Col = 0
GrdDimensionlessTerms.Row = i + 1
GrdDimensionlessTerms.Text = i + 1
GrdDimensionlessTerms.Col = 1
GrdDimensionlessTerms.Row = i + 1
GrdDimensionlessTerms.Text = Pnow

' Checking properties for all pressure steps being analized

R = Pnow / DeltaPressure
Pnow = Pressure(R)
Znow = Zf(R)
Cnow = Compres(R)
ViscR = Vis(R)
MPR = PseudoP(R)

GrdDimensionlessTerms.Col = 2
GrdDimensionlessTerms.Row = i + 1
GrdDimensionlessTerms.Text = Znow


 ' Defining Z factor for Initial Pressure

ZMaxP = Zf(R1)

 ' Calculation of Flow rate from deliverability equation

ViscAvg = (ViscR + ViscWF) / 2
DeltaMP = MPR - MPwf
Re = Sqr(Area * 43560 / 3.1416)
Xi = (MaxPi / Zf(R1)) / (Pwf / Zwf)

 Term = (10.06 * Area * 43560) / (CA * Rw ^ 2)

'Defining Terms of the deliverability equation BQ^2+AQ+DeltaMP=0

A = (1422 * (Temp + 460)) / (Permeability * h) * ((0.5 * Log(Term)) - 0.75 + Skin)
Beta = (27300000000#) / (Permeability ^ 1.1045)
B = ((0.000000000003161) * Beta * (Temp + 460) * Gravity) / (h ^ 2 * ViscAvg) * (1 / Rw - 1 / Re)
MQ = Sqr(A ^ 2 + 4 * B * DeltaMP)
Q = (-A + MQ) / (2 * B)
```

```
Qnow = Q

 ' Defining Initial Flowrate and Fndi

If (counter = 0) Then
Qinitial = Q * 1.006
Fndi = (Qinitial * B / A) + 1
End If

If (Qi = 0) Then GoTo 5000

' Defining Average Flow Rate for each step of pressure and
' Initial Gas in Place from Material Balance Equation

Qavg = (Qnow + Qi) / 2
Bgi = 0.02829 * Zi * (Temp + 460) / Pi    'CF/SCF
Bgf = 0.02829 * Znow * (Temp + 460) / Pnow
Gi = Area * 43560 * h * Porosity * Sg * (1 / Bgi)
If (counter = 1) Then
iGp = Gi
End If

' Cumulative Production calculation

GpScf = (Gi * (Bgf - Bgi)) / Bgf
GpMcf = GpScf / 1000
CumGPSCF = CumGPSCF + GpScf

' Calculation of Dimensionless parameters

Timedays = GpMcf / Qavg
Timeyears = Timedays / 365
CumulativeTimeyears = CumulativeTimeyears + Timeyears
Dq(counter) = Qavg / Qinitial
DGp(counter) = CumGPSCF / iGp
Dt(counter) = (Qinitial * CumulativeTimeyears * 365) / iGp * 1000
CumulativeTimeDays = CumulativeTimeyears * 365

' Calculation of a, and b terms of the deliverability equation for current conditions

DeltaPseudopressure = (PseudoP(R1) - PseudoP(R2))
ADeliverability = DeltaPseudopressure / (Qinitial * Fndi)
BDeliverability = (Fndi - 1) * ADeliverability / Qinitial
Flowrate = (-ADeliverability + (Sqr(ADeliverability ^ 2 + (4 * BDeliverability * DeltaPseudopressure)))) / (2
* BDeliverability)
Lbl17.Caption = Format(ADeliverability, "0")
Lbl19.Caption = Format(BDeliverability, "0.00")
Lbl21.Caption = Format(DeltaPseudopressure, "0.00")

'Printing Dimensionless results in the table

With GrdDimensionlessTerms

.Col = 3: .Row = i + 1: .Text = MPR
.Col = 4: .Row = i + 1: .Text = Format(CumulativeTimeDays, "0.00")
.Col = 5: .Row = i + 1: .Text = Format(Qavg, "0.00")
.Col = 6: .Row = i + 1: .Text = Format(CumGPSCF, "0,000,000.00")
.Col = 7: .Row = i + 1: .Text = Format(Dt(counter), "0.000000")
.Col = 8: .Row = i + 1: .Text = Format(Dq(counter), "0.000000")
```

```
.Col = 9: .Row = i + 1: .Text = Format(DGp(counter), "0.000000")
End With

TxtFndi.Text = Format(Fndi, "0.000")
TxtXi.Text = Format(Xi, "0.000")
TxtQi.Text = Format(Qinitial, "0.00")
TxtGi.Text = iGp
TxtADeliverability = Format(ADeliverability, "0")
TxtBDeliverability = Format(BDeliverability, "0.00")
Lbl17.Visible = True
Lbl18.Visible = True
Lbl19.Visible = True
Lbl20.Visible = True
Lbl21.Visible = True


Print #2, Pnow; ","; Format(CumulativeTimeDays, "0.00"); ","; Format(Qavg, "0.00"); ","; Format(CumGPSCF, "0.00"); _
","; Format(Dt(counter), "0.000000"); ","; Format(Dq(counter), "0.000000"); ","; Format(DGp(counter), "0.000000")

If (Dt(counter) < 0 Or Dq(counter) < 0 Or DGp(counter) < 0) Then
Exit For
End If

5000 Qi = Qnow
Zi = Znow
Pi = Pnow

If ((Pnow - DeltaPressure) < low) Then
Exit For
End If
Next i

Close #2


MSChart2.Visible = True

With MSChart2
   .Plot.Axis(VtChAxisIdX).AxisTitle = "tD"
   .Plot.Axis(VtChAxisIdX).AxisScale.Type = VtChScaleTypeLogarithmic
   .Plot.Axis(VtChAxisIdX).AxisGrid.MinorPen.Style = VtPenStyleNull
   .Plot.Axis(VtChAxisIdY).AxisTitle = "qD"
   .Plot.Axis(VtChAxisIdY).AxisScale.Type = VtChScaleTypeLogarithmic
   .Plot.Axis(VtChAxisIdY).AxisGrid.MinorPen.Style = VtPenStyleNull
   .Plot.UniformAxis = False
   .ShowLegend = False
   .chartType = VtChChartType2dXY
   .ColumnCount = 2
   .RowCount = counter
            For Columns = 1 To .ColumnCount
               For Rows = 1 To .RowCount
               .Column = Columns
               .Row = Rows
                  If Columns = 1 Then
                     .Data = Dt(Rows)
                     ElseIf Columns = 2 Then
                      .Data = Dq(Rows)
```

```
                End If
            Next
        Next
End With

End Sub
```

This portion of code is to find the type curve match for the available Production history

Private Sub CmdGetMatch_Click()

```
Dim count1 As Integer, NData As Integer, Counter1 As Integer, Counter2 As Integer
Dim Gravity As Single, Temp As Single, Permeability As Single, Porosity As Single
Dim Skin As Single
Dim Area As Single, CA As Single, h As Single, Rw As Single, Sg As Single, Pi As Single
Dim DeltaPressure As Single, MaxPi As Single, Zi As Single, Qi As Single
Dim R1 As Single, R2 As Single
Dim i As Integer, i1 As Integer, i2 As Integer, i3 As Integer, i4 As Integer, i5 As Integer
Dim i6 As Integer, i7 As Integer, i8 As Integer, i9 As Integer, i10 As Integer, i11 As Integer
Dim i12 As Integer,  j3 As Integer, j4 As Integer, j2 As Integer
Dim j7 As Integer, j8 As Integer, j9 As Integer, j10 As Integer, j11 As Integer, j12 As Integer
Dim x1 As Single, x2 As Single, x3 As Single, y1 As Single, y2 As Single
Dim low As Single, R As Single, NUMINTEGER As Integer, Zwf As Single, MPwf As Single
Dim ViscWF As Single, Pnow As Single, Znow As Single, Cnow As Single, ViscR As Single
Dim MPR As Single, ZMaxP As Single, ViscAvg As Single, DeltaMP As Single, Re As Single
Dim Xi As Single, Term As Single, A As Single, Beta As Single, B As Single, MQ As Single
Dim Q As Single, Qnow As Single, Qinitial As Single, Fndi As Single
Dim Bgi As Single, Bgf As Single, GpScf As Single, GpMcf As Single
Dim Timedays As Single, Timeyears As Single
Dim ActualData As Integer, Time1(801) As Single, Flowrate1(800) As Single
Dim Flowrate2(801) As Single,  CumulativeTimeyears As Single, CumGPSCF As Single
Dim Dt1(-1 To 801) As Single, DGp1() As Single, Dq1(-1 To 801) As Single
Dim MinPwfValue As Single, MaxPwfValue As Single
Dim PwfSteps As Integer, PwfSteps1 As Single, PwfXi(40) As Single
Dim ValueofPwf As Single, Pwf(100) As Single
Dim MinKValue As Single, MaxKValue As Single, KSteps As Integer, KSteps1 As Single
Dim K2(100) As Single, Min As Single, max As Single, Steps1 As Integer, Steps2 As Single
Dim Gi1(200) As Single, TypeCurveSteps As Single
Dim LSD(801) As Single, TLSD(71, 71, 200) As Single
Dim Gas As Single, Qi_Parameter As Single, Qi_Parameter1 As Single
Dim Gi As Single, Gas_Volume As Double, iGp As Single
Dim ErrorDifference(801) As Single
Dim KParameter As Single, PwfParameter As Single, GiParameter As Single
Dim Ti_Parameter As Single, Ti_Parameter1 As Single
Dim Qi_Parameter2 As Single, Qi_Parameter3 As Single, Ti_Parameter2 As Single
Dim Ti_Parameter3 As Single
Dim MinPwfValue2 As Single, MaxPwfValue2 As Single, PwfSteps2 As Integer
Dim PwfSteps3 As Single, Pwf2(50) As Single
Dim MinKValue2 As Single, MaxKValue2 As Single, KSteps2 As Integer, KSteps3 As Single
Dim K3(50) As Single
Dim Min2 As Single, max2 As Single, Steps3 As Integer, Steps4 As Single, Gi2(50) As Single
Dim TLSD2(50, 50, 50) As Single, Kparameter2 As Single
Dim PwfParameter2 As Single, GiParameter2 As Single
Dim Qavg1() As Single, CumulativeTimeDays1() As Single
Dim Columns As Integer, Rows As Integer
Dim FinalXi As Single, FinalFndi As Single
Dim Qavg2() As Single, CumulativeTimeDays2() As Single
Dim MTLSD As Single, MTLSD2 As Single
Dim gdflag, Percentage_Parameter As Single, Percentage_Parameter1 As Single
```

```
Dim ATLSD(70, 70, 150) As Single, ATLSD2(70, 70, 150) As Single
Dim InitialPseudoPressure As Single, DifferentialPseudopressure As Single, FinalA As Single
Dim FinalB As Single


MSChart1.Visible = False

If OptCartesianPlot1.Value = False And OptLogPlot1.Value = False Then
   MsgBox " Define any type of graphic scale to get Type Curve Match !!", vbExclamation
   Exit Sub
End If

TxtFinalSDE.Text = ""
TxtFinalK.Text = ""
TxtFinalPwf.Text = ""
TxtFinalGi.Text = ""
TxtFinalFndi.Text = ""
TxtFinalXi.Text = ""
TxtFinalA.Text = ""
TxtFinalB.Text = ""
Lbl70.Visible = False: Lbl71.Visible = False: Lbl72.Visible = False: Lbl73.Visible = False: Lbl74.Visible =
False
Lbl75.Visible = False: Lbl76.Visible = False: Lbl77.Visible = False

With MSChart1
   .Plot.Axis(VtChAxisIdX).AxisTitle = "Production Time, Days"
   .Plot.Axis(VtChAxisIdX).AxisScale.Type = VtChScaleTypeLogarithmic
   .Plot.Axis(VtChAxisIdX).AxisGrid.MinorPen.Style = VtPenStyleNull
   .Plot.Axis(VtChAxisIdY).AxisTitle = "Flowrate, Mscf/D"
   .Plot.Axis(VtChAxisIdY).AxisScale.Type = VtChScaleTypeLogarithmic
   .Plot.Axis(VtChAxisIdY).AxisGrid.MinorPen.Style = VtPenStyleNull
   .Plot.UniformAxis = False
   .ShowLegend = True
   .chartType = VtChChartType2dXY
   .ColumnCount = 3
   .RowCount = 5
            For Columns = 1 To .ColumnCount
               For Rows = 1 To .RowCount
               .Column = Columns
               .Row = Rows
                  If Columns = 1 Then
                     .ColumnLabel = ""
                     .Data = ""
                  ElseIf Columns = 2 Then
                     .Data = ""
                   ElseIf Columns = 3 Then
                    .ColumnLabel = ""
                    .Data = ""
                   ElseIf Columns = 4 Then
                    .Data = ""
                  End If
            Next
         Next
End With

MousePointer = 11

Counter1 = -1
```

```
count1 = 0
Open App.Path + TxtGInput.Text + ".txt" For Input As 1
   i = 0
   Do While Not EOF(1)
      i = i + 1
      count1 = count1 + 1
      Input #1, Time1(i), Flowrate1(i)
   Loop
Close #1

NData = count1


Qi_Parameter = Val(TxtInitialQ.Text) * 0.94
Qi_Parameter1 = Val(TxtInitialQ.Text) * 1.06
Ti_Parameter = Val(TxtInitialTime.Text) * 0.96
Ti_Parameter1 = Val(TxtInitialTime.Text) * 1.04


Gravity = Val(TxtGravity.Text)
Temp = Val(TxtTemp.Text)
Permeability = Val(TxtK.Text)
Porosity = Val(TxtPorosity.Text)
Skin = Val(TxtSkin.Text)
Area = Val(TxtArea.Text)
CA = Val(TxtCA.Text)
h = Val(Txth.Text)
Rw = Val(Txtrw.Text)
Sg = Val(TxtSg.Text)
Pi = Val(TxtPi.Text)
DeltaPressure = Val(TxtDPressure.Text)
MaxPi = Pi

gdflag = 0

Qi = 0

R1 = Pi / DeltaPressure



' This loop defines the pressure drawdowns for the specified Xi(s)

MinPwfValue = Val(TxtMinPwf.Text)
MaxPwfValue = Val(TxtMaxPwf.Text)
PwfSteps = 50
PwfSteps1 = Format((MaxPwfValue - MinPwfValue) / (PwfSteps - 1), "0.000")


i1 = 1
For ValueofPwf = MinPwfValue To (MaxPwfValue + 5) Step PwfSteps1
   Pwf(i1) = ValueofPwf
   'Debug.Print "PwfValue(", i1; ")=", Pwf(i1)
   i1 = i1 + 1
Next


R1 = Pi / DeltaPressure
```

```
' This loop defines the values of the Fndi to be analyzed in the comparison process

MinKValue = Val(TxtMinK.Text)
MaxKValue = Val(TxtMaxK.Text)
KSteps = 50
KSteps1 = (MaxKValue - MinKValue) / (KSteps - 1)


For i = 1 To KSteps
K2(i) = MinKValue + (KSteps1 * (i - 1))
'Debug.Print "K("; i; ")=", K2(i)
Next

' This loop defines the values of Gi to be accounted in the comparison process

Min = Val(TxtMinGi1.Text) * 1000000000
max = Val(TxtMaxGi1.Text) * 1000000000
Steps1 = 50
Steps2 = ((max - Min) / (Steps1 - 1))


 For i1 = 1 To Steps1
 Gi1(i1) = Min + (Steps2 * (i1 - 1))
'Debug.Print "Gi("; i1; ")=", Gi1(i1)
 Next

GoTo 6


5:

' This condition in case the initial proposed range does not give any match to gas production

gdflag = 1

Qi_Parameter = Val(TxtInitialQ.Text) * 0.9
Qi_Parameter1 = Val(TxtInitialQ.Text) * 1.12
Ti_Parameter = Val(TxtInitialTime.Text) * 0.9
Ti_Parameter1 = Val(TxtInitialTime.Text) * 1.12


MinPwfValue = Val(TxtMinPwf.Text)
MaxPwfValue = Val(TxtMaxPwf.Text)
PwfSteps = 60
PwfSteps1 = Format((MaxPwfValue - MinPwfValue) / (PwfSteps - 1), "0.000")


i1 = 1
For ValueofPwf = MinPwfValue To (MaxPwfValue + 5) Step PwfSteps1
    Pwf(i1) = ValueofPwf
   'Debug.Print "PwfValue(", i1; ")=", Pwf(i1)
    i1 = i1 + 1
Next


R1 = Pi / DeltaPressure

' This loop defines the values of the Fndi to be analized in the comparison process
```

```
MinKValue = 0.35
MaxKValue = 10
KSteps = 50
KSteps1 = (MaxKValue - MinKValue) / (KSteps - 1)

For i = 1 To KSteps
K2(i) = MinKValue + (KSteps1 * (i - 1))
'Debug.Print "K("; i; ")=", K2(i)
Next

' This loop defines the values of Gi to be accounted in the comparison process

Min = Val(TxtMinGi1.Text) * 1000000000
max = 10000000000# 'Val(TxtMaxGi1.Text) * 1000000000
Steps1 = 100 'Val(TxtGiSteps1.Text)
Steps2 = ((max - Min) / (Steps1 - 1))


 For i1 = 1 To Steps1
 Gi1(i1) = Min + (Steps2 * (i1 - 1))
 'Debug.Print "Gi("; i1; ")=", Gi1(i1)
 Next

6:

PwfParameter = 0
KParameter = 0
GiParameter = 0

MTLSD = 200000000000#

For i3 = 1 To KSteps


      For i2 = 1 To PwfSteps


            For i4 = 1 To Steps1

            Lbl32.Visible = True: Lbl35.Visible = True: Lbl36.Visible = True: Lbl37.Visible = True:
            Lbl38.Visible = True
            Lbl39.Visible = True: Lbl41.Visible = True
            Lbl36.Refresh: Lbl36.Caption = Format(K2(i3), "0.00")
            Lbl38.Refresh: Lbl38.Caption = Format(Pwf(i2), "0.00")
            Lbl41.Refresh: Lbl41.Caption = Format((Gi1(i4) / 1000000000), "0.000")

            Counter1 = -1
            Qi = 0
            TypeCurveSteps = (MaxPi - Pwf(i2)) / DeltaPressure

             ReDim Qavg1(-1 To (TypeCurveSteps + 1))
             ReDim DGp1(-1 To (TypeCurveSteps + 1))
             ReDim CumulativeTimeDays1(-1 To (TypeCurveSteps + 1))

             CumulativeTimeyears = 0
             CumGPSCF = 0
             Qavg1(Counter1) = 0
             Dt1(Counter1) = 0
             DGp1(Counter1) = 0
```

```
Dq1(Counter1) = 0

' Checking properties for Pwf

low = Pwf(i2)

R = Pwf(i2) / DeltaPressure
NUMINTEGER = Int(R)
If R <> NUMINTEGER Then
   Zwf = PwfPROPINTERPOLATED(R, NUMINTEGER, (NUMINTEGER + 1),
   Zf(NUMINTEGER), Zf(NUMINTEGER + 1))
   MPwf = PwfPROPINTERPOLATED(R, NUMINTEGER, (NUMINTEGER + 1),
   PseudoP(NUMINTEGER), _
   PseudoP(NUMINTEGER + 1))
   ViscWF = PwfPROPINTERPOLATED(R, NUMINTEGER, (NUMINTEGER + 1),
   Vis(NUMINTEGER), _
   Vis(NUMINTEGER + 1))
Else
   Zwf = Zf(R)
   MPwf = PseudoP(R)
   ViscWF = Vis(R)
End If

        For i = 0 To 5000

           Counter1 = Counter1 + 1
           Pnow = MaxPi - (i * DeltaPressure)

           R = Pnow / DeltaPressure
           Pnow = Pressure(R)
           Znow = Zf(R)
           Cnow = Compres(R)
           ViscR = Vis(R)
           MPR = PseudoP(R)


           'Defining Z factor for Initial Pressure
           ZMaxP = Zf(R1)


           ViscAvg = (ViscR + ViscWF) / 2
           DeltaMP = MPR - MPwf
           Re = Sqr(Area * 43560 / 3.1416)
           Xi = (MaxPi / Zf(R1)) / (Pwf(i2) / Zwf)

            'Checking if well is fractured or not
           Term = (10.06 * Area * 43560) / (CA * Rw ^ 2)

           'Defining Terms of the deliverability equation BQ^2+AQ+DeltaMP=0

           A = (1422 * (Temp + 460)) / (K2(i3) * h) * ((0.5 * Log(Term)) - 0.75 + Skin)
           Beta = (27300000000#) / (K2(i3) ^ 1.1045)
           B = ((0.000000000003161) * Beta * (Temp + 460) * Gravity) / (h ^ 2 *
           ViscAvg) * (1 / Rw - 1 / Re)
           MQ = Sqr(A ^ 2 + 4 * B * DeltaMP)
           Q = (-A + MQ) / (2 * B)
           Qnow = Q

            ' Defining Fndi
```

```
            If (Counter1 = 0) Then
               Qinitial = Q * 1.006
               Fndi = Format(((Qinitial * B / A) + 1), "0.000")
            End If

            If (Qi = 0) Then GoTo 5000


         ' Defining Initial Gas in Place from Material Balance Equation

         Qavg1(Counter1) = (Qnow + Qi) / 2

         Bgi = 0.02829 * Zi * (Temp + 460) / Pi    'CF/SCF
         Bgf = 0.02829 * Znow * (Temp + 460) / Pnow
         If Counter1 = 1 Then
         Gas_Volume = Gi1(i4) * Bgi
         End If
         Gi = Gas_Volume * (1 / Bgi)
          If (Counter1 = 1) Then
            iGp = Gi
          End If

         ' Cumulative Production calculation
         GpScf = (Gi * (Bgf - Bgi)) / Bgf
         GpMcf = GpScf / 1000
         CumGPSCF = CumGPSCF + GpScf

         ' Calculation of Dimensionless parameters

         Timedays = GpMcf / Qavg1(Counter1)
         Timeyears = Timedays / 365
         CumulativeTimeyears = CumulativeTimeyears + Timeyears
         Dq1(Counter1) = Qavg1(Counter1) / Qinitial
         DGp1(Counter1) = CumGPSCF / iGp
         Dt1(Counter1) = (Qinitial * CumulativeTimeyears * 365) / iGp * 1000
         CumulativeTimeDays1(Counter1) = CumulativeTimeyears * 365

         If Qavg1(1) > Qi_Parameter1 Or Qavg1(1) < Qi_Parameter Or
         CumulativeTimeDays1(1) < Ti_Parameter _
         Or CumulativeTimeDays1(1) > Ti_Parameter1 Then GoTo 20

         If (Dt1(Counter1) < 0 Or Dq1(Counter1) < 0 Or DGp1(Counter1) < 0) Then
            Exit For
         End If

5000      Qi = Qnow
          Zi = Znow
          Pi = Pnow

            If ((Pnow - DeltaPressure) < low) Then
               Exit For
            End If

      Next i
```

****

' SUBROUTINE TO FIND GAS FLOWRATES ON THE TYPE CURVE FOR ACTUAL PRODUCTION TIMES

```
ActualData = Val(TxtSpecifiedNData.Text)

  If Time1(1) >= CumulativeTimeDays1(1) _
  And Time1(ActualData) <= CumulativeTimeDays1(Counter1) And Qavg1(1) >
  Qi_Parameter _
  And Qi_Parameter1 > Qavg1(1) Then

    For i1 = 1 To ActualData

      For i = 1 To Counter1

        If Time1(i1) >= CumulativeTimeDays1(i) And Time1(i1) <=
          CumulativeTimeDays1(i + 1) Then
          Flowrate2(i1) = INTERPOLATED_FlowRate(Time1(i1),
          CumulativeTimeDays1(i), CumulativeTimeDays1(i + 1), _
          Qavg1(i), Qavg1(i + 1))
         ' Debug.Print "Interpolated_Flowrate(", i1; ") =", Flowrate2(i1)
            If i1 = ActualData Then
              Percentage_Parameter = Abs(((Flowrate1(i1) - Flowrate2(i1)) /
              Flowrate1(i1)))

                If gdflag = 1 Then
                  If Percentage_Parameter > 0.08 Then GoTo 20
                    GoTo 12:
                End If


                If Percentage_Parameter > 0.04 Then GoTo 20

            End If
          GoTo 12
        End If

      Next
12:
    Next
  Else: GoTo 20
  End If
```

****

' SUBROUTINE TO FIND LEAST SQUARE DIFFERENCE BETWEEN ACTUAL DATA AND TYPE CURVE

```
ATLSD(i3, i2, i4) = 0
TLSD(i3, i2, i4) = 0
 i5 = 1
  For i = 1 To ActualData
    LSD(i) = ((Abs(Flowrate1(i) - Flowrate2(i))) / Flowrate1(i)) ^ 2
```

```
            TLSD(i3, i2, i4) = TLSD(i3, i2, i4) + LSD(i)

                If i = ActualData Then
                  ATLSD(i3, i2, i4) = TLSD(i3, i2, i4) / ActualData
                  'Debug.Print "ATLSD{"; i3, i2, i4; "} =", ATLSD(i3, i2, i4)
                   If i3 = KSteps And i2 = PwfSteps And i4 = Steps1 Then GoTo 24
                   If i3 = i3 And i2 = PwfSteps And i4 = Steps1 Then GoTo 22
                   If i3 = i3 And i2 = i2 And i4 = Steps1 Then GoTo 21
                   GoTo 23
                End If



          Next


20:         ATLSD(i3, i2, i4) = 200000000000#
            If i3 = KSteps And i2 = PwfSteps And i4 = Steps1 Then GoTo 24
            If i3 = i3 And i2 = PwfSteps And i4 = Steps1 Then GoTo 22
            If i3 = i3 And i2 = i2 And i4 = Steps1 Then GoTo 21

23:
        If ATLSD(i3, i2, i4) < MTLSD Then
            MTLSD = ATLSD(i3, i2, i4)
            KParameter = K2(i3)
            PwfParameter = Pwf(i2)
            GiParameter = Gi1(i4)
            End If
        Next i4

21:
         If ATLSD(i3, i2, i4) < MTLSD Then
            MTLSD = ATLSD(i3, i2, i4)
            KParameter = K2(i3)
            PwfParameter = Pwf(i2)
            GiParameter = Gi1(i4)
            End If
          Next i2

22:
        If ATLSD(i3, i2, i4) < MTLSD Then
            MTLSD = ATLSD(i3, i2, i4)
            KParameter = K2(i3)
            PwfParameter = Pwf(i2)
            GiParameter = Gi1(i4)
            End If
        Next i3
24:



    'TxtFinalSDE.Text = Format(MTLSD, "0.000000000000")
    TxtFinalK.Text = Format(KParameter, "0.00")
    TxtFinalPwf.Text = Format(PwfParameter, "0.00")
    TxtFinalGi.Text = Format((GiParameter / 1000000000), "0.000")


If KParameter = Empty And PwfParameter = Empty And GiParameter = Empty And gdflag = 1 Then
```

```
    TxtFinalK.Text = "No match"
    TxtFinalPwf.Text = "found for"
    TxtFinalGi.Text = "these conditions"
    MsgBox " No match found for these conditions !!", vbExclamation
    GoTo 750:
End If

If KParameter = Empty And PwfParameter = Empty And GiParameter = Empty Then

 TxtFinalK.Text = "Checking"
    TxtFinalPwf.Text = "denser"
    TxtFinalGi.Text = "Interval"
 GoTo 5
End If

'*****************************************************************************************************************
' BEGINING OF THE SECOND AND FINAL STAGE OF DATA REFINING

If gdflag = 1 Then
Qi_Parameter2 = Val(TxtInitialQ.Text) * 0.95
Qi_Parameter3 = Val(TxtInitialQ.Text) * 1.05
Ti_Parameter2 = Val(TxtInitialTime.Text) * 0.95
Ti_Parameter3 = Val(TxtInitialTime.Text) * 1.05
GoTo 400
End If

Qi_Parameter2 = Val(TxtInitialQ.Text) * 0.96
Qi_Parameter3 = Val(TxtInitialQ.Text) * 1.04
Ti_Parameter2 = Val(TxtInitialTime.Text) * 0.96
Ti_Parameter3 = Val(TxtInitialTime.Text) * 1.04

400:

' Defining final Pwf interval to analize

MinPwfValue2 = PwfParameter * 0.9
MaxPwfValue2 = PwfParameter * 1.1
PwfSteps2 = 30
PwfSteps3 = Format((MaxPwfValue2 - MinPwfValue2) / (PwfSteps2 - 1), "0.000")

For i1 = 1 To PwfSteps2
Pwf2(i1) = MinPwfValue2 + (PwfSteps3 * (i1 - 1))
'Debug.Print "Pwf("; i1; ")=", Pwf2(i1)
Next


' Defining final Permeability Interval to analize

MinKValue2 = KParameter * 0.9
MaxKValue2 = KParameter * 1.1
KSteps2 = 30
KSteps3 = (MaxKValue2 - MinKValue2) / (KSteps2 - 1)


For i = 1 To KSteps2
K3(i) = MinKValue2 + (KSteps3 * (i - 1))
'Debug.Print "K("; i; ")=", K3(i)
Next
```

```
' Defining final Initial Gas in place Interval to analyze

Min2 = GiParameter * 0.9
max2 = GiParameter * 1.1
Steps3 = 30
Steps4 = ((max2 - Min2) / (Steps3 - 1))

 For i1 = 1 To Steps3
 Gi2(i1) = Min2 + (Steps4 * (i1 - 1))
' Debug.Print "Gi("; i1; ")=", Gi2(i1)
 Next


Kparameter2 = 0
PwfParameter2 = 0
GiParameter2 = 0

MTLSD2 = 200000000000#


For j3 = 1 To KSteps2


      For j2 = 1 To PwfSteps2


           For j4 = 1 To Steps3

           Lbl32.Visible = True: Lbl35.Visible = True: Lbl36.Visible = True: Lbl37.Visible = True:
           Lbl38.Visible = True
           Lbl39.Visible = True: Lbl41.Visible = True
           Lbl36.Refresh: Lbl36.Caption = Format(K3(j3), "0.00")
           Lbl38.Refresh: Lbl38.Caption = Format(Pwf2(j2), "0.00")
           Lbl41.Refresh: Lbl41.Caption = Format((Gi2(j4) / 1000000000), "0.000")

           Counter1 = -1
           Qi = 0
           TypeCurveSteps = (MaxPi - Pwf2(j2)) / DeltaPressure

            ReDim Qavg1(-1 To (TypeCurveSteps + 1))
            ReDim DGp1(-1 To (TypeCurveSteps + 1))
            ReDim CumulativeTimeDays1(-1 To (TypeCurveSteps + 1))

            CumulativeTimeyears = 0
            CumGPSCF = 0
            Qavg1(Counter1) = 0
            Dt1(Counter1) = 0
            DGp1(Counter1) = 0
            Dq1(Counter1) = 0

            ' Checking properties for Pwf

            low = Pwf2(j2)

            R = Pwf2(j2) / DeltaPressure
            NUMINTEGER = Int(R)
            If R <> NUMINTEGER Then

               Zwf = PwfPROPINTERPOLATED(R, NUMINTEGER, (NUMINTEGER + 1),
```

```
    Zf(NUMINTEGER), Zf(NUMINTEGER + 1))
    MPwf = PwfPROPINTERPOLATED(R, NUMINTEGER, (NUMINTEGER + 1),
    PseudoP(NUMINTEGER), _
    PseudoP(NUMINTEGER + 1))
    ViscWF = PwfPROPINTERPOLATED(R, NUMINTEGER, (NUMINTEGER + 1),
    Vis(NUMINTEGER), _
    Vis(NUMINTEGER + 1))
Else
    Zwf = Zf(R)
    MPwf = PseudoP(R)
    ViscWF = Vis(R)
End If

        For i = 0 To 5000

            Counter1 = Counter1 + 1
            Pnow = MaxPi - (i * DeltaPressure)

            R = Pnow / DeltaPressure
            Pnow = Pressure(R)
            Znow = Zf(R)
            Cnow = Compres(R)
            ViscR = Vis(R)
            MPR = PseudoP(R)


            'Defining Z factor for Initial Pressure
            ZMaxP = Zf(R1)


            ViscAvg = (ViscR + ViscWF) / 2
            DeltaMP = MPR - MPwf
            Re = Sqr(Area * 43560 / 3.1416) '(Sqr(Area * 43560)) / 2
            Xi = (MaxPi / Zf(R1)) / (Pwf2(j2) / Zwf)

             'Checking if well is fractured or not
            Term = (10.06 * Area * 43560) / (CA * Rw ^ 2)

            'Defining Terms of the deliverability equation BQ^2+AQ+DeltaMP=0

            A = (1422 * (Temp + 460)) / (K3(j3) * h) * ((0.5 * Log(Term)) - 0.75 + Skin)
            Beta = (27300000000#) / (K3(j3) ^ 1.1045)
            B = ((0.000000000003161) * Beta * (Temp + 460) * Gravity) / (h ^ 2 *
            ViscAvg) * (1 / Rw - 1 / Re)
            MQ = Sqr(A ^ 2 + 4 * B * DeltaMP)
            Q = (-A + MQ) / (2 * B)
            Qnow = Q

             ' Defining Fndi
               If (Counter1 = 0) Then
                   Qinitial = Q * 1.006
                   Fndi = Format(((Qinitial * B / A) + 1), "0.000")
               End If

               If (Qi = 0) Then GoTo 5002
```

```
' Defining Initial Gas in Place from Material Balance Equation

                    Qavg1(Counter1) = (Qnow + Qi) / 2

                    Bgi = 0.02829 * Zi * (Temp + 460) / Pi    'CF/SCF
                    Bgf = 0.02829 * Znow * (Temp + 460) / Pnow
                    If Counter1 = 1 Then
                    Gas_Volume = Gi2(j4) * Bgi
                    End If
                    Gi = Gas_Volume * (1 / Bgi)
                     If (Counter1 = 1) Then
                       iGp = Gi
                     End If

                    ' Cumulative Production calculation
                    GpScf = (Gi * (Bgf - Bgi)) / Bgf
                    GpMcf = GpScf / 1000
                    CumGPSCF = CumGPSCF + GpScf

                    ' Calculation of Dimensionless parameters

                    Timedays = GpMcf / Qavg1(Counter1)
                    Timeyears = Timedays / 365
                    CumulativeTimeyears = CumulativeTimeyears + Timeyears
                    Dq1(Counter1) = Qavg1(Counter1) / Qinitial
                    DGp1(Counter1) = CumGPSCF / iGp
                    Dt1(Counter1) = (Qinitial * CumulativeTimeyears * 365) / iGp * 1000
                    CumulativeTimeDays1(Counter1) = CumulativeTimeyears * 365

                    If Qavg1(1) > Qi_Parameter3 Or Qavg1(1) < Qi_Parameter2 Or
                      CumulativeTimeDays1(1) < Ti_Parameter2 _
                      Or CumulativeTimeDays1(1) > Ti_Parameter3 Then GoTo 120

                     If (Dt1(Counter1) < 0 Or Dq1(Counter1) < 0 Or DGp1(Counter1) < 0) Then
                          Exit For
                     End If

5002                 Qi = Qnow
                     Zi = Znow
                     Pi = Pnow

                       If ((Pnow - DeltaPressure) < low) Then
                          Exit For
                       End If

                  Next i

'*****************************************************************************************************************

' SUBROUTINE TO FIND CORRESPONDENT FLOWRATES ON THE TYPE CURVE FOR  ACTUAL
PRODUCTION TIMES

            ActualData = Val(TxtSpecifiedNData.Text)

               If Time1(1) >= CumulativeTimeDays1(1) _
               And Time1(ActualData) <= CumulativeTimeDays1(Counter1) And Qavg1(1) >
               Qi_Parameter _
               And Qi_Parameter1 > Qavg1(1) Then
```

```
                For i1 = 1 To ActualData

                  For i = 1 To Counter1

                    If Time1(i1) >= CumulativeTimeDays1(i) And Time1(i1) <=
                      CumulativeTimeDays1(i + 1) Then
                      Flowrate2(i1) = INTERPOLATED_FlowRate(Time1(i1),
                      CumulativeTimeDays1(i), CumulativeTimeDays1(i + 1), _
                      Qavg1(i), Qavg1(i + 1))
                     'Debug.Print "Interpolated_Flowrate(", i1; ") =", Flowrate2(i1)
                        If i1 = ActualData Then
                            Percentage_Parameter1 = Abs(((Flowrate1(i1) - Flowrate2(i1)) /
                            Flowrate1(i1)))
                               If Percentage_Parameter1 > 0.03 Then GoTo 120
                         End If
                      GoTo 13
                    End If

                  Next
13:
                Next
              Else: GoTo 120
              End If

*****************************************************************************************************

' SUBROUTINE TO FIND LEAST SQUARE DIFFERENCE BETWEEN ACTUAL DATA AND TYPE
CURVE


            TLSD2(j3, j2, j4) = 0
            ATLSD2(j3, j2, j4) = 0
             i5 = 1
               For i = 1 To ActualData
                  LSD(i) = ((Abs(Flowrate1(i) - Flowrate2(i))) / Flowrate1(i)) ^ 2

                TLSD2(j3, j2, j4) = TLSD2(j3, j2, j4) + LSD(i)

                  If i = ActualData Then

                    ATLSD2(j3, j2, j4) = TLSD2(j3, j2, j4) / ActualData
                   ' Debug.Print "ATLSD{"; j3, j2, j4; "} =", ATLSD2(j3, j2, j4)
                    If j3 = KSteps2 And j2 = PwfSteps2 And j4 = Steps3 Then GoTo 124
                    If j3 = j3 And j2 = PwfSteps2 And j4 = Steps3 Then GoTo 122
                    If j3 = j3 And j2 = j2 And j4 = Steps3 Then GoTo 121
                    GoTo 123
                  End If


              Next


120:          ATLSD2(j3, j2, j4) = 200000000000#


             If j3 = KSteps2 And j2 = PwfSteps2 And j4 = Steps3 Then GoTo 124
             If j3 = j3 And j2 = PwfSteps2 And j4 = Steps3 Then GoTo 122
             If j3 = j3 And j2 = j2 And j4 = Steps3 Then GoTo 121
```

```
123:

        If ATLSD2(j3, j2, j4) < MTLSD2 Then
           MTLSD2 = ATLSD2(j3, j2, j4)
           Kparameter2 = K3(j3)
           PwfParameter2 = Pwf2(j2)
           GiParameter2 = Gi2(j4)
           End If
         Next j4

121:

         If ATLSD2(j3, j2, j4) < MTLSD2 Then
           MTLSD2 = ATLSD2(j3, j2, j4)
           Kparameter2 = K3(j3)
           PwfParameter2 = Pwf2(j2)
           GiParameter2 = Gi2(j4)
           End If
        Next j2

122:
         If ATLSD2(j3, j2, j4) < MTLSD2 Then
           MTLSD2 = ATLSD2(j3, j2, j4)
           Kparameter2 = K3(j3)
           PwfParameter2 = Pwf2(j2)
           GiParameter2 = Gi2(j4)
           End If
          Next j3
124:




'  DEFINITION OF THE MATCHED TYPE CURVE FOR CURRENT GAS PRODUCTION

         Counter2 = -1
         Qi = 0
         TypeCurveSteps = (MaxPi - PwfParameter2) / DeltaPressure

          If ActualData > TypeCurveSteps Then
          ReDim Qavg2(-1 To ActualData)
          ReDim DGp1(-1 To ActualData)
          ReDim CumulativeTimeDays2(-1 To ActualData)
          GoTo 300
          End If

          ReDim Qavg2(-1 To (TypeCurveSteps + 1))
          ReDim DGp1(-1 To (TypeCurveSteps + 1))
          ReDim CumulativeTimeDays2(-1 To (TypeCurveSteps + 1))
300:

          CumulativeTimeyears = 0
          CumGPSCF = 0
          Qavg2(Counter2) = 0
          Dt1(Counter2) = 0
          DGp1(Counter2) = 0
          Dq1(Counter2) = 0
```

```
' Checking properties for Pwf

low = PwfParameter2

R = PwfParameter2 / DeltaPressure
NUMINTEGER = Int(R)
If R <> NUMINTEGER Then
   Zwf = PwfPROPINTERPOLATED(R, NUMINTEGER, (NUMINTEGER + 1),
   Zf(NUMINTEGER), Zf(NUMINTEGER + 1))
   MPwf = PwfPROPINTERPOLATED(R, NUMINTEGER, (NUMINTEGER + 1),
   PseudoP(NUMINTEGER), _
   PseudoP(NUMINTEGER + 1))
   ViscWF = PwfPROPINTERPOLATED(R, NUMINTEGER, (NUMINTEGER + 1),
   Vis(NUMINTEGER), _
   Vis(NUMINTEGER + 1))
Else
   Zwf = Zf(R)
   MPwf = PseudoP(R)
   ViscWF = Vis(R)
End If

        For i = 0 To 5000

           Counter2 = Counter2 + 1
           Pnow = MaxPi - (i * DeltaPressure)

           R = Pnow / DeltaPressure
           Pnow = Pressure(R)
           Znow = Zf(R)
           Cnow = Compres(R)
           ViscR = Vis(R)
           MPR = PseudoP(R)

           If i = 0 Then
             InitialPseudoPressure = MPR
           End If


           'Defining Z factor for Initial Pressure
           ZMaxP = Zf(R1)


           ViscAvg = (ViscR + ViscWF) / 2
           DeltaMP = MPR - MPwf
           Re = Sqr(Area * 43560 / 3.1416) '(Sqr(Area * 43560)) / 2
           FinalXi = (MaxPi / Zf(R1)) / (PwfParameter2 / Zwf)

            'Checking if well is fractured or not
           Term = (10.06 * Area * 43560) / (CA * Rw ^ 2)

           'Defining Terms of the deliverability equation BQ^2+AQ+DeltaMP=0

           A = (1422 * (Temp + 460)) / (Kparameter2 * h) * ((0.5 * Log(Term)) - 0.75 +
           Skin)
           Beta = (27300000000#) / (Kparameter2 ^ 1.1045)
           B = ((0.000000000003161) * Beta * (Temp + 460) * Gravity) / (h ^ 2 *
           ViscAvg) * (1 / Rw - 1 / Re)
           MQ = Sqr(A ^ 2 + 4 * B * DeltaMP)
```

```
            Q = (-A + MQ) / (2 * B)
            Qnow = Q

             ' Defining Fndi
               If (Counter2 = 0) Then
                  Qinitial = Q * 1.006
                  FinalFndi = Format(((Qinitial * B / A) + 1), "0.000")
                  DifferentialPseudopressure = Format((InitialPseudoPressure - MPwf),
                  "0.000")
                  FinalA = DifferentialPseudopressure / (FinalFndi * Qinitial)
                  FinalB = (FinalA * (FinalFndi - 1)) / Qinitial
               End If

               If (Qi = 0) Then GoTo 5003


            ' Defining Initial Gas in Place from Material Balance Equation

            Qavg2(Counter2) = (Qnow + Qi) / 2

            Bgi = 0.02829 * Zi * (Temp + 460) / Pi    'CF/SCF
            Bgf = 0.02829 * Znow * (Temp + 460) / Pnow
            If Counter2 = 1 Then
            Gas_Volume = GiParameter2 * Bgi
            End If
            Gi = Gas_Volume * (1 / Bgi)
             If (Counter2 = 1) Then
               iGp = Gi
             End If

            ' Cumulative Production calculation
            GpScf = (Gi * (Bgf - Bgi)) / Bgf
            GpMcf = GpScf / 1000
            CumGPSCF = CumGPSCF + GpScf

            ' Calculation of Dimensionless parameters

            Timedays = GpMcf / Qavg2(Counter2)
            Timeyears = Timedays / 365
            CumulativeTimeyears = CumulativeTimeyears + Timeyears
            Dq1(Counter2) = Qavg2(Counter2) / Qinitial
            DGp1(Counter2) = CumGPSCF / iGp
            Dt1(Counter2) = (Qinitial * CumulativeTimeyears * 365) / iGp * 1000
            CumulativeTimeDays2(Counter2) = CumulativeTimeyears * 365


               If (Dt1(Counter2) < 0 Or Dq1(Counter2) < 0 Or DGp1(Counter2) < 0) Then
                  Exit For
               End If

5003         Qi = Qnow
            Zi = Znow
            Pi = Pnow

               If ((Pnow - DeltaPressure) < low) Then
                  Exit For
               End If

         Next i
```

```
Lbl32.Visible = False: Lbl35.Visible = False: Lbl36.Visible = False: Lbl37.Visible = False: Lbl38.Visible =
False
            Lbl39.Visible = False: Lbl41.Visible = False


'*****************************************************************************************************************
' PLOTTING TYPE CURVE MATCH FOR PRODUCTION HISTORY


 With MSChart1
   .Plot.Axis(VtChAxisIdX).AxisTitle = "Production Time, days"
      If OptCartesianPlot1.Value = True Then
         .Plot.Axis(VtChAxisIdX).AxisScale.Type = VtChScaleTypeLinear
      GoTo 115
      End If
   .Plot.Axis(VtChAxisIdX).AxisScale.Type = VtChScaleTypeLogarithmic
115:
   .Plot.Axis(VtChAxisIdX).AxisGrid.MinorPen.Style = VtPenStyleNull
   .Plot.Axis(VtChAxisIdY).AxisTitle = "Flowrate, Mscf/D"
         If OptCartesianPlot1.Value = True Then
            .Plot.Axis(VtChAxisIdY).AxisScale.Type = VtChScaleTypeLinear
            GoTo 116
         End If
   .Plot.Axis(VtChAxisIdY).AxisScale.Type = VtChScaleTypeLogarithmic
116:
   .Plot.Axis(VtChAxisIdY).AxisGrid.MinorPen.Style = VtPenStyleNull
   .Plot.UniformAxis = False
   .ShowLegend = True
   .chartType = VtChChartType2dXY
   .ColumnCount = 4
   .RowCount = Counter2
            If ActualData > Counter2 Then
               .RowCount = ActualData
            End If
               For Columns = 1 To .ColumnCount
                  For Rows = 1 To .RowCount
                  .Column = Columns
                  .Row = Rows
                     If Columns = 1 Then
                     .ColumnLabel = "Type Curve"
                        If Rows > Counter2 Then
                           CumulativeTimeDays2(Rows) = CumulativeTimeDays2(Counter2)
                        End If
                        .Data = CumulativeTimeDays2(Rows)
                        ElseIf Columns = 2 Then
                           If Rows > Counter2 Then
                              Qavg2(Rows) = Qavg2(Counter2)
                           End If
                        .Data = Qavg2(Rows)
                        ElseIf Columns = 3 Then
                        .ColumnLabel = "Production"
                           If Rows > ActualData Then
                              Time1(Rows) = Time1(ActualData)
                           End If
                        .Data = Time1(Rows)
                        ElseIf Columns = 4 Then
                           If Rows > ActualData Then
                              Flowrate1(Rows) = Flowrate1(ActualData)
```

```
                    End If
                .Data = Flowrate1(Rows)
            End If
        Next
    Next
End With
MSChart1.Visible = True
Lbl70.Visible = True: Lbl71.Visible = True: Lbl72.Visible = True: Lbl73.Visible = True: Lbl74.Visible =
True
Lbl75.Visible = True: Lbl76.Visible = True: Lbl77.Visible = True


  TxtFinalSDE.Text = Format(MTLSD2, "0.00000000000") '
  TxtFinalK.Text = Format(Kparameter2, "0.00")
  TxtFinalPwf.Text = Format(PwfParameter2, "0.00")
  TxtPwf.Text = Format(PwfParameter2, "0.00")
  TxtFinalGi.Text = Format((GiParameter2 / 1000000000), "0.000")
  TxtFinalFndi.Text = Format(FinalFndi, "0.00")
  TxtFinalXi.Text = Format(FinalXi, "0.00")
  TxtFinalA.Text = Format(FinalA, "0.00")
  TxtFinalB.Text = Format(FinalB, "0.00")
  Lbl70.Caption = Format(FinalA, "0.00")
  Lbl72.Caption = Format(FinalB, "0.00")
  Lbl74.Caption = (InitialPseudoPressure)


750:

MousePointer = 1

End Sub
```