USING MULTI-LAYER MODELS TO FORECAST GAS FLOW RATES IN TIGHT GAS RESERVOIRS

A Thesis

by

SERGIO ARMANDO JEREZ VERA

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2006

Major Subject: Petroleum Engineering

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Committee Members, Duane A. McVay
Ray James
Head of Department, Stephen A. Holditch

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ABSTRACT

Using Multi-Layer Models to Forecast Gas Flow Rates in Tight Gas Reservoirs.

(December 2006)

Sergio Armando Jerez Vera, B.S., Texas A&M University

Chair of Advisory Committee: Dr. Stephen A. Holditch

The petroleum industry commonly uses single-layer models to characterize and forecast long-term production in tight gas reservoir systems. However, most tight gas reservoirs are layered systems where the permeability and porosity of each layer can vary significantly, often over several orders of magnitude. In addition, the drainage areas of each of the layers can be substantially different. Due to the complexity of such reservoirs, the analysis of pressure and production history using single-layer analyses techniques provide incorrect estimates of permeability, fracture conductivity, drainage area, and fracture half-length. These erroneous values of reservoir properties also provide the reservoir engineer with misleading values of forecasted gas recovery.

The main objectives of this research project are: (1) to demonstrate the typical errors that can occur in reservoir properties when single-layer modeling methods are used to history match production data from typical layered tight gas reservoirs, and (2) to use the single-layer match to demonstrate the error that can occur when forecasting long-term gas production for such complex gas reservoirs. A finite-difference reservoir simulator was used to simulate gas production from various layered tight gas reservoirs.

These synthetic production data were analyzed using single-layer models to determine reservoir properties. The estimated reservoir properties obtained from the history matches were then used to forecast ten years of cumulative gas production and to find the accuracy of gas reserves estimated for tight gas reservoirs when a single-layer model is used for the analysis.

Based on the results obtained in this work, I conclude that the accuracy in reservoir properties and future gas flow rates in layered tight gas reservoirs when analyzed using a single-layer model is a function of the degree of variability in permeability within the layers and the availability of production data to be analyzed. In cases where there is an idea that the reservoir presents a large variability in ‘’k”, using a multi-layer model to analyze the production data will provide the reservoir engineer with more accurate estimates of long-term production recovery and reservoir properties.

DEDICATION

First of all I would like to dedicate this thesis to my Mom and Dad, who I miss daily.

To my siblings, Cesar and Nidia, who are my role-models and have given me unconditional love.

To the rest of my family for always supporting me.

To Leslie for believing in me.

To my Lord, God for everything.

ACKNOWLEDGMENTS

I wish to express my sincerest gratitude to the following people without whom I would not have been able to complete this work: Dr. Stephen A. Holditch, head of the Petroleum Engineering Department and chair of my graduate committee, for his advice, knowledge, and support; Dr. Duane A. McVay and Dr. Ray James for serving as members of my graduate committee; Dr. John Spivey for his expertise and helpful advice on production history matching; Ms. Darla-Jean Weatherford for her understanding and concern for technical writing; Mr. Charles Ozobeme for sharing all his experience and knowledge in the petroleum field with me; all the officemates and classmates for their friendship and continuous support; and finally to Texas A&M University for the education I have received and for being the home that I could never forget.

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CHAPTER I

INTRODUCTION

1.1 Tight Gas Reservoir Characteristics

Because of the rapid depletion of conventional oil and gas reservoirs not only in North America but also all over the world, the petroleum industry has had the need to explore and develop new sources of energy supply such as natural gas from unconventional tight reservoirs.[1] Because of the increasing gas prices and improved drilling, completion, and stimulation technologies, operating companies now have the ability to economically develop many unconventional gas reservoirs.

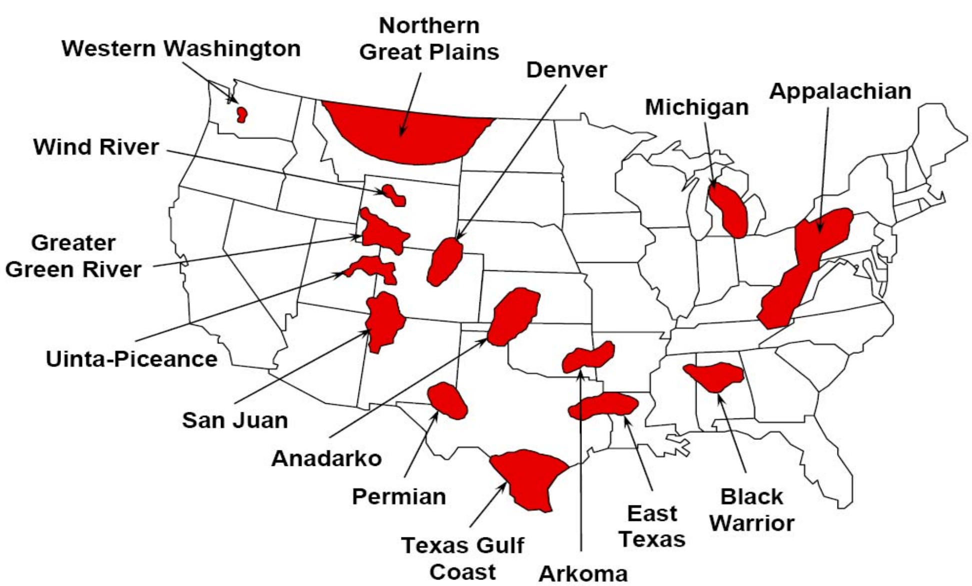

Fig. 1.1 *Tight Gas Basins in the United States* [2]

This thesis follows the style of the *SPE Journal.*

In North America, “tight gas sands account for 20% of the total gas production, but the U.S Energy Information Administration estimates that tight gas sands could account for up to 35% of the country’s recoverable gas resources”.[1] Fig. 1.1 shows the main tight gas sand basins in the United States that may possibly contain from 315 to 350 tcf of recoverable natural gas.[2]

Typical tight gas formations are complex layered systems that mainly occur in widespread ancient channels[3] and can be in blanket or lenticular forms. Tight gas formations have an average in-situ permeability to gas of less than 0.1 millidarcies and sometimes as low as 0.001 millidarcies.[4] To produce commercial quantities of gas at economical rates from tight gas reservoirs, massive hydraulic fracturing treatments need to be successfully designed and implemented.[2]

Tight gas formations are heterogeneous in nature consisting of sandstone, siltstone, and shale dispersed vertically and horizontally throughout the formation.[5] These layers of sandstone, siltstone, and shale can present a high contrast in values of permeability, porosity, and gas saturation depending on various geological aspects such as depositional environment, depth/time of burial, deposition sequence, and post-depositional activities (e.g. tectonic and digenesis).[6] Hence, evaluating the performance of such complex systems can become a challenge. Frequently, the complexity will lead us to misinterpret the reservoir behavior when we use simple models to analyze data from these complex reservoirs. Fig. 1.2 shows a typical log of a tight gas sand interval in the Cotton Valley formation in North Louisiana. In this log the gamma ray (GR) and the resistivity measurements show different intervals of sand pay with hydrocarbon existence.

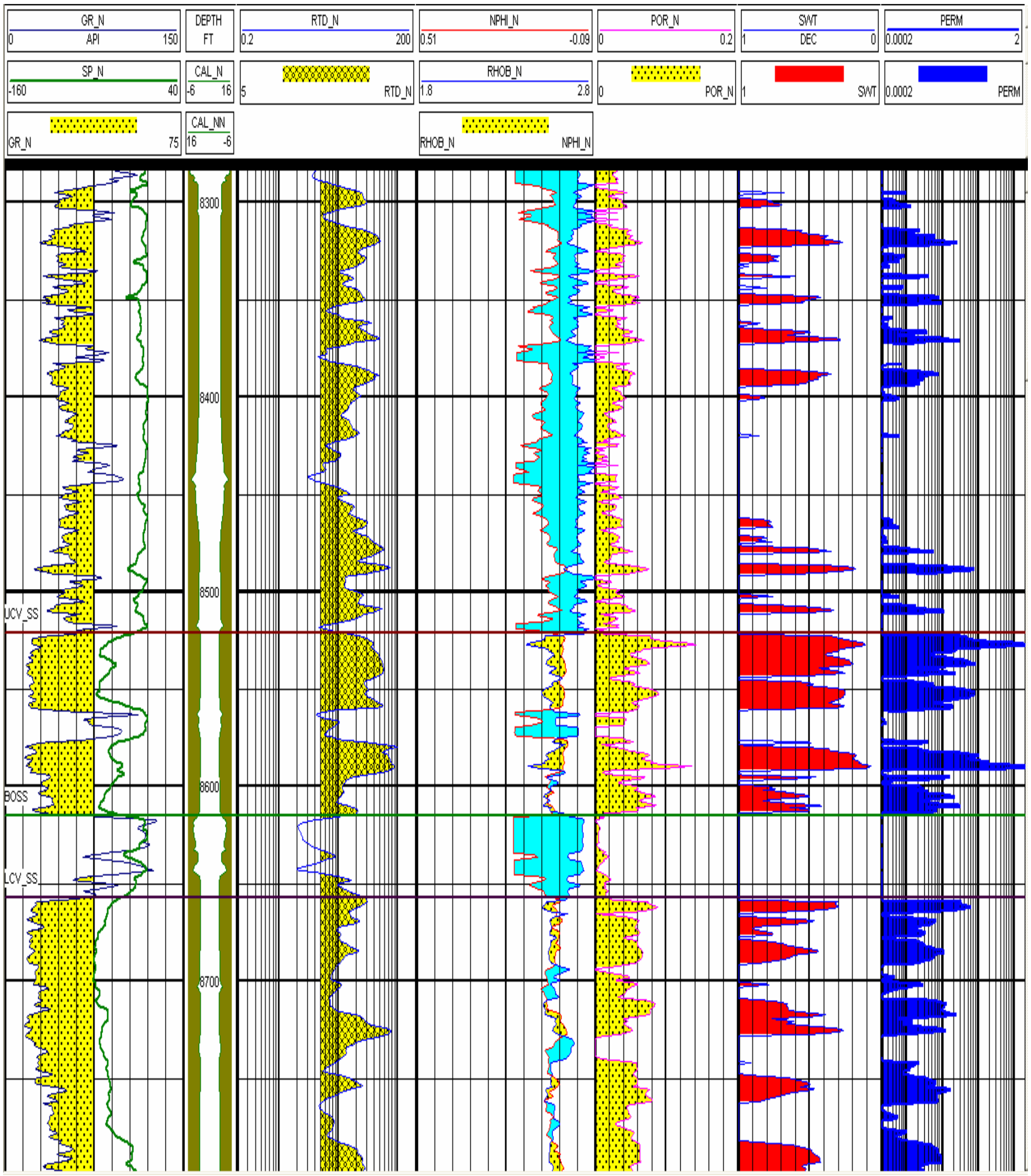

Fig. 1.2 *Typical Tight Gas Sand Log Interval (Cotton Valley Formation)*

These different layers observed by the gamma ray present different values of porosity ranging from 2% to 14%, permeability varying within four orders of magnitude from 0.0002 to 2 md, and different water saturations within the layers.

1.2 Well Performance and Forecasting Reserves in Tight Gas Reservoirs

Different reservoir engineering techniques have been developed, assessed, and improved throughout the years to estimate oil and gas reservoir properties and reserves. Tight gas reservoirs, however, present a major challenge when estimating reservoir properties and gas reserves due to the complexity of such layered reservoirs and also to the length of time required before the pressure transient reaches the boundaries of the reservoir. The length of time to reach semi-steady state flow could be weeks, months, or even years depending on the value of permeability in the reservoir and the areal extent of the drainage area of the well.[7, 8] Table 1.1 exhibits the effects of permeability and drainage area on the time required for the pressure to reach the reservoir boundaries (stabilization time) for a reservoir with the following reservoir properties and conditions: (1) gas specific gravity of 0.6, (2) formation temperature at 210 ^{o}F, (3) average pressure of 3500 psi (c_g=2.468X10^{-4} psia^{-1} and μ_g=0.02 cp), and (4) a formation porosity of 10%.

Table 1.1 *Effects on Permeability and Radial Drainage Area on Stabilization Time for an Unstimulated Well* [9]

k	**A**	**ts**
(md)	(acres)	
0.01	40	3 years
0.01	640	47 years
0.1	40	108 days
0.1	640	4.7 years
1.0	40	10.8 days
1.0	640	173 days
10	40	1.1 days
10	640	17.3 days
100	40	0.11 days
100	640	1.73 days
1000	40	0.011 days
1000	640	0.17 days

Among the different techniques that reservoir engineers commonly apply to determine reservoir properties and predict gas well production are volumetric equations, material balance equations, and production data analysis methods.[2]

Volumetric methods use subsurface maps of the reservoir such as structural, cross-sectional, and isopach maps in conjunction with pyramidal or trapezoidal methods to calculate the volume of oil and gas in place.[9, 10] The subsurface maps are based on data obtained in part from well logs, core analyses, bottom-hole pressure, and fluid sample information. The accuracy of volumetric estimates depends on availability of sufficient data to characterize the areal extent of the reservoir and variations in net thickness; therefore, in the early productive life of the reservoir, when data are available from only a few wells, the volumetric method is the least accurate of all methods for estimating oil and gas reserves.[9] In addition, it is very difficult to estimate drainage area and recovery efficiency in layered, tight gas reservoir. As such, volumetric estimates of ultimate gas recovery are not reliable in tight gas reservoir.

Materials balance calculations are based on the principle of conservation of mass (e.g. original mass – produced mass = remaining mass). Materials balance can be used to analyze the past performance and predict future performance of a reservoir at any state of the reservoir depletion provided the wells can be shut-in and accurate values of the reservoir pressure can be estimated. The calculations involved in material balance assume that the void created in the reservoir due to hydrocarbon production is filled immediately by expansion of the remaining hydrocarbons, the rock, and possibly, an aquifer. Eqs 1.1 and 1.2 represent the general materials balance equations for gas reservoirs with an aquifer influx and with no aquifer influx, respectively.[9] Materials balance calculations estimate gas volumes that can actually be recovered; however, materials balance rarely works on tight gas reservoirs because it is very difficult to shut-in tight gas wells long enough to obtain accurate values of initial pressure (p_i) and/or average reservoir pressure $\left(\overline{P}\right)$.[7-9] Without accurate pressure data, material balance methods will not provide reliable values of recoverable gas volumes .

$$GB_{gi} = (G - G_p)B_g + \Delta V_w + \Delta V_f + (W_e - W_p)B_w \quad \ldots\ldots 1.1$$

$$\frac{\overline{P}}{z} = \frac{P_i}{z_i}\left(1 - \frac{G_p}{G}\right) \quad \ldots\ldots 1.2$$

In tight gas reservoir, it is almost impossible to obtain accurate estimates of average reservoir pressure from the producing wells. As such, materials balance methods do not provide reliable estimates of ultimate gas recovery.

Production data analysis (PDA) is another approach that can be used to estimate field performance (e.g., oil and gas recovery) under different production schemes. PDA can be accomplished using decline curve analyses, finite-difference models, or analytical equations to match real production data with a model of the reservoir.[11] Reservoir simulators deal with fluid flow through porous media and determine how the reservoir pressure declines as the hydrocarbons are being produced. Numerical simulation is one of the most accurate techniques to estimate reservoir performance if enough geological, petrophysical, and production data are available to build the reservoir model. However, simulation can become a costly method to apply and may not be time efficient if a lot of wells have to be history matched.

Production data analysis methods (PDA) using curve fitting routines are the most widely used methods to analyze well performance and estimate gas and oil reserves without having an extensive knowledge of the reservoir. These methods include conventional decline curve analysis,[12] advanced decline curve analysis,[13] and history matching analysis using analytical models. However, most of the PDA methods make the assumption that the gas is being produced from a single layer reservoir. When the reservoir is a layered system, which is almost always the case, then decline curves or simple analytical models may not provide accurate estimates of current conditions or of future production. As an example, Table 1.2 shows the reservoir properties for 28 wells located in the Caspiana and Elm grove fields in North Louisiana. The reservoir properties for the wells were estimated using a single-layer analytical simulator by Matador Resources. However, it is hard to believe that the wells are draining from such small drainage areas. Also, some of the fracture half-lengths estimated by the single-layer model are to small for the large amount of propant pumped in the wells from that region.

1.3 Objectives of Study

The main objectives of this research project are (1) to demonstrate the typical errors that can occur in reservoir properties when single-layer modeling methods are used to history match production data from typical, layered tight gas reservoirs, and then (2) to use the match to demonstrate the error that can occur when forecasting reserves for such complex gas reservoirs.

Table 1.2 *Reservoir Properties Results for 28 Wells in the Caspiana and Elm Grove Fields, Analyzed by Matador Resources Using a Single-layer Analytical Simulator*

API	Lease Name	Well Number	Gas Cum (Mscf)	kh (md-ft)	k (md)	h (ft)	Lf (ft)	wkf (md-ft)	Area (acres)	OGIP (Mscf)
17013203320000	HOSS CV RA SUH;CONLEY ENT INC	1	69324	0.23	0.002261	100			1.5	136900
17015208100000	CV RA SU 48;SNYDER	2	668871	1	0.01	100	310	120	11.3	714900
17015210650000	CV RA SU108;J T WHITE	1	319550	0.72	0.007162	100			5.3	470500
17015214880000	CV RA SU115; TOMMY TAYLOR W	1	156385	0.47	0.004749	100	64	1000	3.4	215300
17015215790000	CV RA SU119;TOMMY TAYLOR Y	2	180948	0.26	0.002564	100	100	1000	3.4	299300
17015227860000	CV RA SU 108; RE SMITH JR TRUST	1	373703	0.13	0.00133	100	286	200	6.8	603100
17015229550000	LCV RA SUZ;ELSTON 20	1	109597	0.43	0.004343	100	9	1000	3.6	225000
17015229560000	CV RA SUL;MORRIS 33	1	824864	1.31	0.01313	100	117	1000	26.8	1944000
17015229670000	CV RA SU84;GARDNER 7	2	366836	0.43	0.00427	100	148	133.4	7.8	585200
17015230020000	CV RA SU11;H L TOMPKINS	003AL	1027033	0.76	0.007645	100	512	20450	20	1505000
17015230440000	CV RA SU113;SNYDER OIL CORP 35	001AL	1157937	0.96	0.009589	100	542	21380	22.4	1688000
17015230610000	CV RA SU26;HARVILLE 11	001AL	866093	1.6	0.01596	100	176	237.3	20.9	1546000
17015231180000	CV RA SU125;HALL 25	001AL	333374	0.82	0.008202	100	89	51.04	7.2	544200
17017215270000	CV RA SU60 CECILIA E SMITH	1	149682	0.28	0.002812	100	158	20	2	178000
17017215270000	CV RA SU60 CECILIA E SMITH	1	149682	0.28	0.002812	100	158	20	2	178000
17017221550000	CV RA SU 72;CUPPLES	4	186659	0.92	0.009191	100			1	91300
17017324060000	CV RA SU16;SAM W SMITH 28	1	903230	0.87	0.008723	100			11	841300
17017324230000	CV RA SU55;LEVEE BOARD 22	1	242075	0.25	0.0025	100	232	200	4.1	362400
17017325070000	CV RA SU54;ELLERBE HEIRS 21	002AL	351394	0.26	0.00257	100			8	610200
17017333330000	CV RA SU63;SAM W SMITH ETAL 32	1	334968	0.98	0.00978	100	72	20	14.2	1319000
17017333450000	CV RA SU64;CL HUCKABEE ETAL	1	356243	1.15	0.01145	100	76	100	14.5	1104000
17031215180000	CV RA SU68;GUY	1	1484130	0.55	0.005506	100	186	100	32	2441000
17031230280000	CV RA SU 69; HUNT PLYWOOD B	1	483445	0.2	0.001568	125	363	200	10	953400
17031230300000	CV RA SUU; HUNT PLYWOOD C	1	367374	0.17	0.00138	125	144	200	22	2097000
17031230470000	CV RA SUU; HUNT PLYWOOD C	003AL	427405	0.22	0.001742	125	210	200	8	762700
17031230510000	CV RA SUV; HUNT PLYWOOD	002AL	371192	0.34	0.003414	100	86	50	8.7	776700
17081203700000	CV RA SUA;SAMPLE	1	510632	0.14	0.0014	100			15	1144000
17081204210000	CV RA SUB;SAMPLE	2	213423	0.08	0.0007996	100			4.1	313500

CHAPTER II

LITERATURE REVIEW

2.1 Introduction

Over the years there have been numerous publications on different production data analysis methods used to analyze wells and to predict the future performance of oil and gas wells. Analytical solutions for production data analysis methods have constantly been reassessed and improved to estimate reservoir properties and reserves. However, when it comes to dealing with complex, layered tight gas reservoirs, these methods may not provide accurate forecasts.

2.2 Decline Curve Analysis

Arps[12] published equations that can be used to analyze production data and to predict future well performance and ultimate reserves. Arps' technique was simply an extrapolation procedure of flow rate vs. time based on two main assumptions: (1) the future behavior of the well would be governed and mathematically characterized by any trends of its past performance and (2) those trends would also have to remain unchanged throughout the life of the well. These two assumptions make such a technique completely empirical and sometimes unreliable.

Arps[9] later recognized that the characteristics of production decline could not be represented by a single mathematical formula, but three different formulas (or shapes) had to be used depending on the decline exponent "b" as shown in Fig. 2.1. To describe the production decline of most wells, one could use exponential, hyperbolic, or harmonic equations to match early data and forecast the future production.

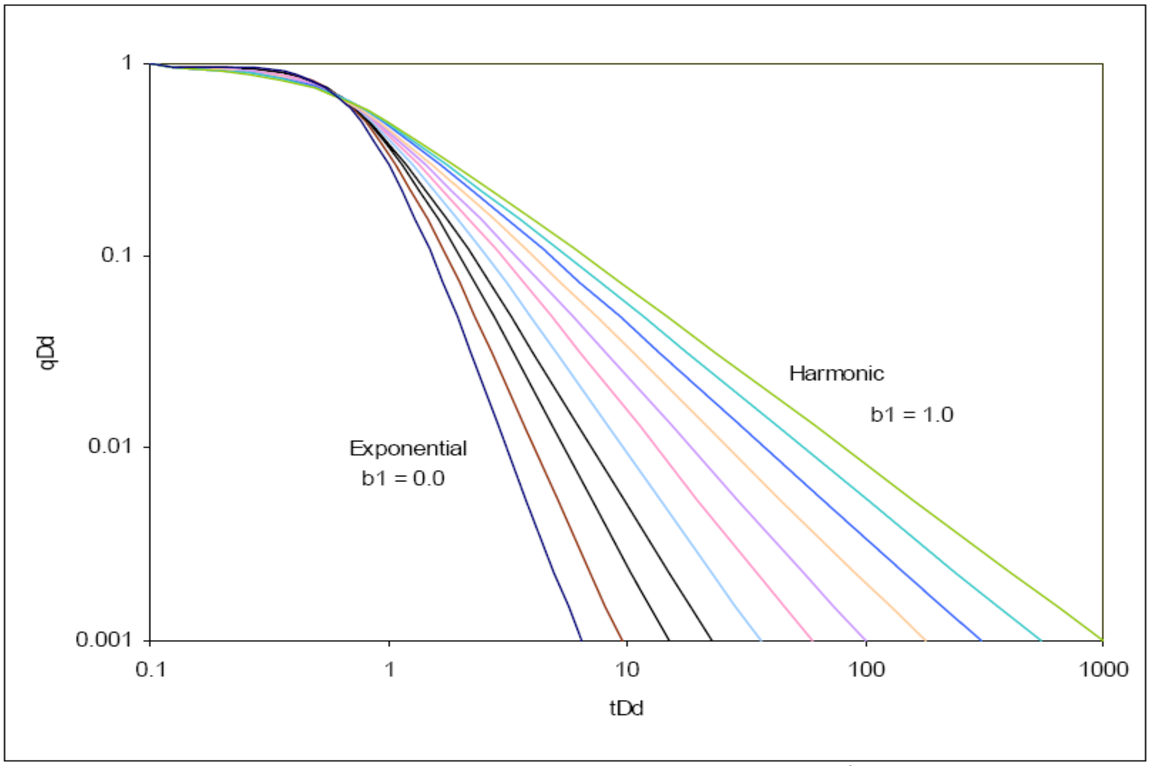

Fig. 2.1 *Types of Decline Curves by Arps* [10]

2.2.1 Exponential Decline (b=0)

Exponential decline is also called "Constant-Percentage Decline",[9] and as its name states, is characterized by a constant decrease in production proportional to the production rate of the well. When the decline exponent b is zero, we can say that the decline is exponential and that flow rate and cumulative production can be mathematically expressed by Eqs 2.1 and 2.2, respectively.

$$q_{(t)} = q_{(i)} e^{-D_i t} \quad \ldots\ldots 2.1$$

$$G_{p(t)} = -\frac{1}{Di} q_{(t)} + \frac{q_{(i)}}{D_{(i)}} \quad \ldots\ldots 2.2$$

2.1.2 Hyperbolic Decline (0<b<1)

When the production decline is no longer constant and has a decline exponent greater than zero but smaller than one, the production decline is known as hyperbolic decline[9] and can be described by using Eq 2.3. The cumulative production-time relationship for hyperbolic decline can be also obtained by integrating the flow rate equation (Eq 2.3) and can be expressed by Eq 2.4. When the hyperbolic decline is compared to the exponential decline, the hyperbolic decline equations estimate longer production times for a well as its decline exponent value approaches one.[10]

$$q_{(t)} = \frac{q_{(i)}}{(1 + bD_i t)^{1/b}} \quad \ldots\ldots 2.3$$

$$G_{p(t)} = \left(\frac{q_{(i)}^{b}}{D_i (b-1)} \right) \{ q_{(t)}^{(1-b)} - q_{(i)}^{(1-b)} \} \quad \ldots\ldots 2.4$$

2.2.3 Harmonic Decline (b=1)

Harmonic decline was the third form that production decline could take according to Arps. This type of decline has been used for oil wells that had a long life expectation and also for wells where production was affected by gravity drainage.[10] Flow rate and cumulative production for harmonic decline could be described by Eqs 2.5 and 2.6.

$$q_{(t)} = \frac{q_{(i)}}{(1 + D_i t)} \quad \ldots\ldots 2.5$$

$$G_{p(t)} = \left(\frac{q_{(i)}}{D_i} \right) \{\log q_{(i)} - \log q_{(t)}\} \quad \ldots\ldots 2.6$$

2.3 Advanced Decline Curve Analysis

In 1970, Fetkovich[13, 14] combined analytical solutions to the flow equation in the transient region with Arps' empirical equations as described in Eqs 2.7-2.8 and generated a set of dimensionless log-log type curves as shown in Fig. 2.2. This improvement in the technique first developed by Arps[9] permitted not only a graphical analysis of the well performance after the well had reached pseudo-steady flow, but also in the early period of the well when the production was still in the transient flow. However, Fetkovich type curves were only useful for oil wells and were based on the assumption of an ideal well that was located in the center of a circular drainage area and that was produced at constant flowing bottom-hole pressure with no-flow boundaries.[9]

$$q_D = \frac{141.3q(t)\mu B}{kh(p_i - p_{wf})} \quad \text{.......... 2.7}$$

$$t_D = \frac{0.00634kt}{\phi \mu c_t r_w^2} \quad \text{.......... 2.8}$$

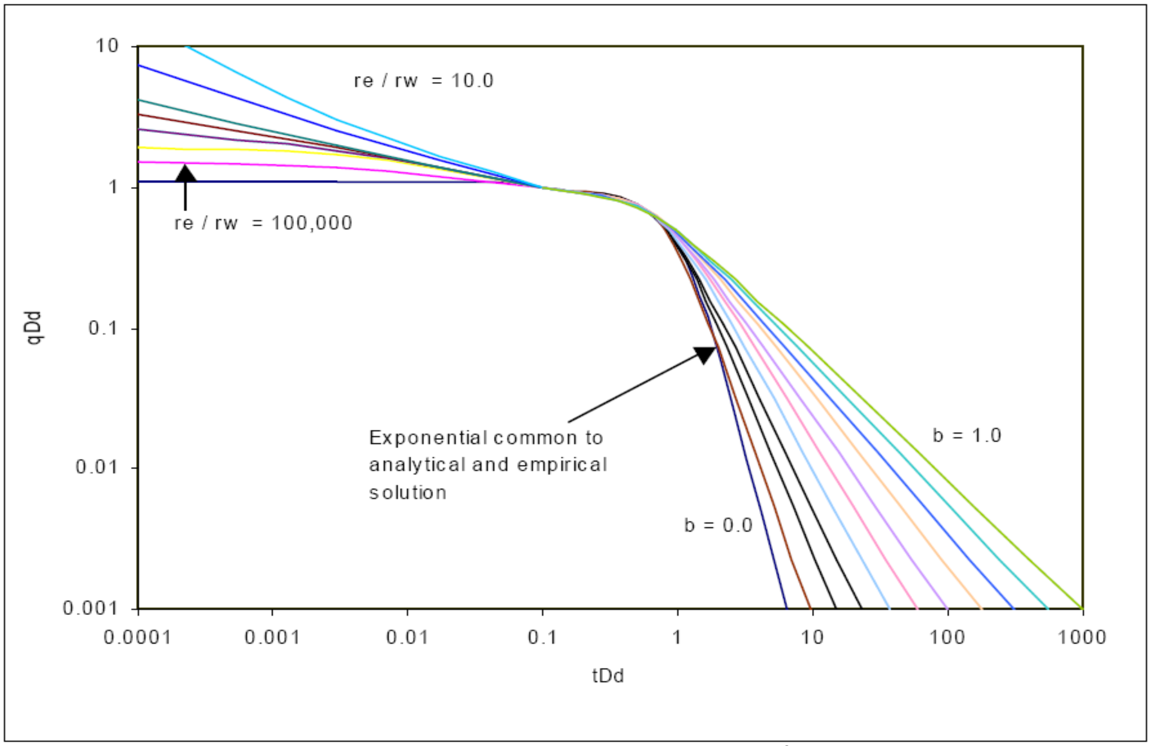

Fig. 2.2 *Fetkovich Type Curves* [10]

In 1980, Fetkovich[13] proposed a new set of type curves for advanced decline curve analysis for solution-gas drive reservoirs and gas reservoirs with constant pressure at the inner boundary. He combined a back-pressure gas rate equation (Eq 2.9) with the materials balance equation Eq 2.10 onto a rate-time equation for gas wells as described in Eq 2.11, and then he generated the new set of type curves as shown in Fig. 2.3.

$$q_g = C_g\left(\overline{p}_R^2 - p_{wf}^2\right)^n \quad \text{.......} 2.9$$

$$\overline{p}_R = -\left(\frac{\overline{p}_{Ri}}{G}\right)G_p + \overline{p}_{Ri} \quad \text{.......} 2.10$$

$$\frac{q_g(t)}{q_{gi}} = \frac{1}{\left[(2n-1)\left(\frac{q_{gi}}{G}\right)t + 1\right]^{\frac{2n}{2n+1}}} \quad \text{.......} 2.11$$

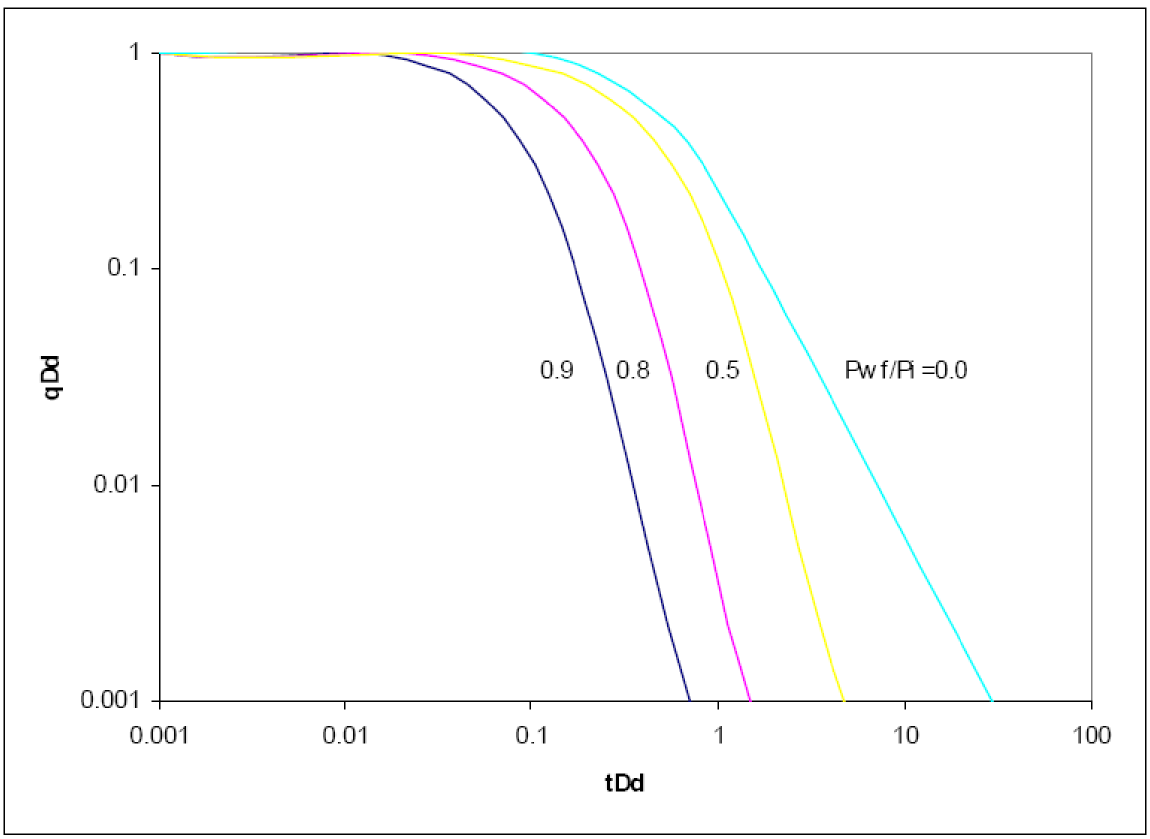

Fig. 2.3 *Fetkovich Type Curves for Gas Wells* [10]

The advanced decline curve analysis technique was not only useful to estimate reserves, but also to estimate reservoir properties such as permeability, hydraulic fracture dimensions, skin factor, and drainage area.[14, 15] These new features developed for the technique made advanced decline curve analysis one of the most useful tools for production data analysis for conventional reservoirs throughout the years.

2.4 Advances in Analytical Solutions for Gas Well Performance

In 1983, Rodgers *et al.* [16] proposed an analytical solution to evaluate single-layer gas reservoirs considering variable nonstatic bottom-hole-pressure. Applying this new method led to simultaneous determinations of reservoir pressure history, gas in place, and other parameters relevant to water influx and effective compressibility. Rodgers' method coupled the pseudo steady-state flow equation with the materials balance equation through non-linear regression to minimize the two main shortcomings that previous methods presented, such as the estimation of the reservoir shape and the relationship between the average pressure and the viscosity-compressibility product.

In 1985, Carter[17] presented a new set of type curves for finite radial and linear gas-flow systems based on definitions of dimensionless rate q_D and time t_D. Carter modified q_D and t_D equations to let solutions for the radius ratio R approach unity, and therefore, letting linear gas-flow systems be represented in his method. He also introduced the parameter λ, as shown in Eq 2.12, to represent variations in the decline curves from real gas properties. A value of λ =1 represented a liquid case and values of

$\lambda < 1.0$ represented the degree of gas property variation as a result of the severity of the drawdown.

$$\lambda = \frac{\mu(p_i)c_g(p_i)}{\mu c_g} \qquad \text{2.12}$$

In 1987, Fraim and Wattenbarger[18] developed a normalized time equation as shown in Eq 2.13 to improve Fetkovich type curves for gas well analysis. The main function of the normalized time equation was to linearize the gas diffusivity equation creating an equivalent liquid response, thus, allowing liquid flow solutions to be used for the analysis of gas production data. The normalized time introduced in their work was different from the pseudo-time concept introduced in previous years because the compressibility and viscosities were evaluated at the average reservoir pressure rather than the wellbore pressure. This method also accounted for boundary-dominated flow as well as transient flow. However, the normalized time equation did not consider the effects of non-Darcy flow.

$$t_n = \int_0^1 \frac{(\mu c_t)_i}{\mu(\bar{p})c_t(\bar{p})} dt \qquad \text{2.13}$$

In 1990, Fetkovich *et al.*[19] analyzed multi-layer gas reservoirs by using type-curve matching. They found out that the all field and well rate-time data they analyzed for layered-reservoirs reached values for hyperbolic decline exponent “b” greater than 0.5. Fetkovich, therefore, concluded that values of “b” greater than 0.5 but smaller than 1.0 for gas reservoirs could be obtained with a layered-reservoir description if sufficient contrast in layer properties were present.

In the same year, Aminian *et al.*[20] developed another set of type curves that were based on a constant-pressure solution for gas wells experiencing pseudosteady-state flow. Aminian’s type curves were developed mainly to account for factors that previous advanced decline-curve techniques did not account for in well performance analysis for gas wells such as non-Darcy flow, pressure dependency of gas viscosity, and compressibility and the shape factor of the drainage area of the well.

In 1991, Blasingame *et al.*[21] proposed a new approach for analyzing production decline data for gas wells producing at variable flowing bottomhole pressure and variable flow rate. This new method was based on the transformation of the boundary dominated solutions for constant rate and constant pressure production by using a superposition function to account for variances of pressure and flow rate.

Spivey and Frantz[22] found out that the method of modeling variable pressure history by using superposition of constant pressure solutions proposed by Blasingame *et al.*[21] did not accurately model production in real wells. Each pressure change would result in a spike in the resulting production rate and in practice wells are often operated such that pressure declines slowly and smoothly until line pressure is reached. The investigators, therefore, developed a new procedure for calculating production rate and cumulative production using superposition of solutions for botomhole pressure which varies linearly with time.

In 1993, Palacio and Blasingame[23] extended Fraim and Wattenbarger's work[18] into a gas production analysis method that coupled material balance analysis, decline curve analysis, and pressure transient techniques into a more powerful tool to analyze well performance in gas wells. The proposed method used an expression called pseudo-equivalent time t_a as shown in Eq 2.14 to convert gas well production with varying rate and pressure into equivalent constant rate liquid data.

$$t_a = \frac{(\mu c_g)_i}{q(t)} \int_0^t \frac{q(t')dt'}{\mu(\overline{P})c_g(\overline{P})} = \frac{(\mu c_g)_i z_i G_i}{q(t) 2 P_i} \Delta\left[m(\overline{P})\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{ 2.14}$$

In 1994, Keating *et al.*[24] presented a new approach to estimate original gas in place (OGIP) for single-layer gas reservoirs by coupling the material balance equation with the stabilized flow equation. Keating's approach also coupled the stabilized flow equation to the integral of the material balance equation as shown in Eq 2.15 to estimate a future decline curve for such gas reservoirs. However, one of the disadvantages of this new approach was that it assumed stabilized flow for the future decline curve even if such had not been reached yet.

$$\int_{\frac{pi}{Zi}}^{\frac{\overline{p}}{Z}} d\left(\frac{p}{z}\right)' = -\frac{pi}{ZiG} \int_0^1 q_g \, dt' \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{ 2.15}$$

Other authors[25, 26] also developed various approximations of coupling material balance equation with the gas flow equation for single-layer gas reservoirs to estimate gas reserves. However only a few studies have been performed to estimate gas reserves in low permeability layered reservoirs.

In 1996, El-Banbi and Wattenbarger[27] modified previous work presented by different authors[25, 26] on coupling the material balance equation with the stabilized flow equation at constant bottomhole pressure into a stabilized flow model for multi-layer gas reservoirs. They found out that performance from single-layer stabilized flow models can be added for all the layers in the multi-layer systems by using Eq 2.16; and, that production data from multi-layer reservoirs could be analyzed by layered stabilized flow models with the use of an optimization routine. This piece of work, however, has not been so popular among reservoir engineers when dealing with low permeability gas reservoirs because the method is only accurate on wells that have reached pseudo-steady state flow, and as presented in previous sections, low permeability reservoirs may take weeks, months, or even years to reach pseudo-steady state flow.

$$q_T(t) = \sum_{j=1}^{nlayers} q_{gi}(t) \qquad \text{2.16}$$

In 1997, El-Banbi and Wattenbarger[28] presented an extension of their Layered Stabilized Flow Model (LSFM). Their method accounted for bottom-hole flowing pressure variations and non-Darcy flow effects.

2.5 Production History Matching Using Analytical Reservoir Simulators

The objective of production history matching is to use a model to determine a reservoir description that generates production data that best matches real production data from a well. In the past, this task used to be done manually, but varying the parameters of a reservoir description by hand until a satisfactory match was time consuming and frequently inefficient.

Computerized history matching, non-linear regression algorithms[29-31] referred to as "automatic history matching" were developed to help improve the process. Some forms of automatic history matching use a gradient-based optimization technique that automatically varies the reservoir parameters until a history match of the field or well is obtained. This mechanical process also offers a feature such that the user can fix any reservoir parameter that he or she is confident in, and obtain the match by varying only the parameters that are unknown or uncertain.[8]

The main drawback of automatic history matching is that if one does not have a good understanding of the description of the reservoir, the history matching solution may become non-unique.[32] To help lessen the non-uniqueness of the history match solutions, the reservoir engineer can correlate geological data, core data, log data, and well test data together to develop a better understanding of the reservoir. If one provides accurate initial values of reservoir properties to the PDA software, then one maximizes the chances that a valid method can be obtained.

After reviewing the literature on production history analysis, in the attempt to find the best production history analysis suitable for my research project, I found out that all the techniques used in the industry are mainly single-phase, single-layer techniques. Therefore, I used in this research project the widely used production history matching technique by an analytical reservoir simulator.

2.6 Studies on Describing Tight Layered Reservoirs

Several field studies on describing layered tight reservoirs have been performed and published in the literature for many years now. However, they have been mostly focused on the Barnett Shale and the Devonian gas shales of the U.S Appalachian Basin. Only a few studies on describing layered reservoirs have been performed on tight gas sands in the Travis Peak formation in East Texas.

In 1987 Holditch, Robinson, and Whitehead[33] did a thorough analysis of the multi-layer Travis Peak formation in East Texas. They described comprehensive geological, coring, logging, well testing, fracture treatment monitoring and fracture diagnostic studies that were used to better understand the reservoir geometry as well as the rock properties in the layers surrounding the main productive interval. Holditch, Robinson, and Whitehead concluded that to better understand, correctly analyze, and predict well performance in complex layered reservoir systems such that from the Travis Peak formation, it was absolutely necessary that the formation be clearly described in three dimensions by integrating all the studies and analyses mentioned above.

In 1992, Lancaster *et al.*[34] evaluated the completion, stimulation and testing of the Barnett shale wells operated by Mitchell Energy Corporation (MEC) in Fort Worth Basin of North-central Texas. On the basis of the data collected and analyzed, Lancaster *et al.* concluded that the Barnett Shale appeared to be characterized best with a layered (two-layer) reservoir description. They also concluded that the gas production in most of the wells in the Barnett Shale was associated with thin, high permeability, naturally fractured zones; although, most of the gas in place was confined to thicker, extremely low permeability layers.

Gatens and Lee[35] also published some work on using layered reservoir descriptions for the analysis of gas reservoirs in the Devonian shale. In the work by Gatens and Lee, they looked at the case where the Devonian shale contains multiple layers with different values of permeability in each layer. Typically, most of the permeability is located in thin layer and most of the gas in place is located in thick, continuous layers. When you run a radial, pre-fracture well test, the early time flow rate is dominated by the high permeability streaks. As such, the value of permeability-thickness product (*kh*) from a pre-fracture well test is dominated by the high permeability layers. However, most of the gas in place is located in the low permeability layers. The problem comes when one used the kh from the pre-fracture well test to forecast reserves using a single-layer model. When you divide the value of kh by the total thickness, h, you will always compute an estimate of k that is too large. Then, when you use the value of k in a single layer model to forecast reserves, you will always overestimate the reserves because the “k” you used in the model is large than the ‘k’ in the low permeability layers that contain most of the gas in place. In their work, Gatens and Lee also presented a semi-empirical method to develop an approximate layered reservoir description to predict long term performance and to design stimulation treatments. Such semi-empirical method consisted of integrating log analysis, flow/build up tests, production logs, geologic reservoir, and description information into a layered reservoir model to predict well performance. Although, this method may give an approximate layered description of the reservoir, the testing required for the layered reservoir description is time consuming and usually too expensive to be applied in low permeability formations.

Frantz *et al.*[36] developed a multi-layer description for the Gas Research Institute (GRI) Comprehensive Study Well 2 (CSW2) which was a hydraulically fractured, low permeability formation completed in the Devonian shales. Frantz *et al* discovered that a two-layer description of the reservoir would best describe all the data collected on the CSW2, including pre-fracture flow/buildup tests, and post-fracture isolation, communication, nitrogen injection/falloff, flow/buildup, and microcosmic test and production data.

In 1993, Jochen and Lancaster[37] in conjunction with the Gas Research Institute (GRI) characterized an eastern Kentucky Devonian shale well (COOP 1). After a complete integration of geological, geophysical, geochemical data, Jochen and Lancaster came up with an eleven-layer, naturally fractured reservoir model that realistically matched the pre- and post-fracture production history of the well. They concluded that the integration of various test analysis such as log tests, core tests, nitrogen slug test and pre-and post-fracture buildup tests are essential to better understand the complexity of reservoir as well as the physical properties controlling well performance in the Devonian Shales. However, all the tests performed on this well, which are rarely performed due to economic feasibility in tight gas reservoirs, were part of the three-well research program sponsored by the GRI.

In 1994, Lee and Hopkins[38], in their attempt to better characterize tight gas reservoirs presented general procedures for developing tight reservoir descriptions using data from three field examples. Two of the field examples best modeled short-term transient behavior and long-term boundary-dominated behavior by using a layered reservoir description, while the third example was appropriately modeled by a single layer description. Lee and Hopkins concluded that because of the diverse nature of tight gas reservoirs, a single procedure to determine what level of reservoir characterization is needed in these complex reservoirs is practically impossible to obtain. The level of reservoir characterization has to be obtained on a case-by-case basis.

Spivey[39] developed a fully-coupled reservoir/wellbore single-well analytical simulator for multilayer gas reservoirs that can be used to automatically history match production and production log data simultaneously. Spivey's simulator can be used to history match data from multiple production logs as well as surface production data and provides estimates of individual layer properties such as permeability, fracture length, and drainage area. After performing various tests, Spivey revealed that his analytical simulator gave more accurate results than allocation methods commonly used in the petroleum industry. Although this simulator gives good estimates of permeability and fracture half-length, the drainage area of the well can be underestimated if the production history used for the match is still in the transient flow period. Production logs are also required for the history matching analysis; however, operating companies scarcely run production logs on their wells.

CHAPTER III

METHODOLOGY

3.1 Introduction

In this research study production data for a vertical well containing a vertical hydraulic fracture and producing from a typical layered tight gas reservoir were generated by using a finite-difference black oil reservoir simulator (ECLIPSE version 2005a). The reservoir data used in this work resembles the data often observed in the Cotton Valley formation in East Texas or Northern Louisiana. Three main scenarios that describe typical tight gas reservoirs[33] were considered in the reservoir simulations. Production Data were generated for a single layer case, two-layer cases, and three-layer cases. The production data were analyzed using both a single-layer and a multi-layer analytical model to investigate typical errors that can occur when one analyzes production data to forecast ultimate recovery.

The following methodology was used in this research work:

1. I analyzed logs and reviewed the literature to obtain representative examples of layered reservoirs in the Cotton Valley formation.
2. I next developed scenarios and tables of runs needed and set up Eclipse for the three simulation model scenarios used in this work.
3. A single layer model was run and the reservoir properties were back calculated using history matching analysis to validate grid and time step sizes and evaluation techniques.

4. A total of 153 runs were made for 3 scenarios using different permeability, drainage areas, and fracture half-lengths, as shown in Table 3.1.

Table 3.1 *Range of Data Varied in Simulation Scenarios*

Scenario	Layers		k (md)	L_f (ft)	Area (acres)
1	2	Top Bottom	0.1-10 0.01	180-600	40-160
2	2	Top Bottom	0.1-10 0.01	180-600	20-40 160
3	3	Top Middle Bottom	0.1 10 0.01	180-600	80-160 20 80-160

5. I analyzed production data with a single-layer model for three different data sets. The first data set used only the first month of production history to compute the permeability-thickness product (kh), fracture half-length (L_f) and drainage area (A). The second data set used the first year of production data to analyze the reservoir. The third data set used the first three years of production data in the analysis. Obviously, as more production data are included in the analyses, one would expect the accuracy of the analyses to improve.
6. Using the results from step 5, I forecasted the ten-year gas production using the single-layer model results for the three different cases.
7. I next analyzed the error in forecasting the 10-year recovery for all the cases.
8. I evaluated selected cases using a multi-layer model for scenario one, two and three to compare the results from these cases to the results obtained from the analysis of the same cases performed with the single-layer description.

9. I then developed conclusions and recommendation on the best methods to evaluate and interpret PDA results in layered, tight gas wells.

3.2 Reservoir Description for Simulation

The tight gas reservoir considered for the simulations had the following characteristics: (1) reservoir is horizontal, (2) square geometry with the well centered in the drainage area, (3) single-porosity, (4) isotropic within the layers, with (5) closed boundaries. Table 3.2 summarizes the selected reservoir properties and conditions for this study. These parameters where chosen to resemble the Cotton Valley formation in Northeast Texas and Northeast Louisiana.[33]

Table 3.2 *General Reservoir Data for Simulation Runs*

Depth, ft	10000
Net Pay Thickness, ft	100
Original Reservoir Pressure, psia	4500
Flowing Bottom-Hole Pressure, psia	450
Bottom-Hole Temperature, ^oF	220
Formation Porosity, %	10
Gas Specific Gravity	0.65
Gas Viscosity, cp	0.02335
Gas Compressibility, psi^{-1}	2.81E-04
Rock Compressibility, psi^{-1}	4.00E-06

3.3 Hydraulic Fracture Characteristics

The hydraulic fracture has a constant width (w_f) of 0.004 ft, from the wellbore to the tip. The fracture extends on both sides of the wellbore and has fracture conductivity

($w_f\, k_f$) of 400 md-ft. A small (180 ft), medium (350 ft), and large (600 ft) fracture half-length (L_f) were considered for the simulations. Fig. 3.1 shows a plan view of fracture half- lengths and the reservoir and grid system.

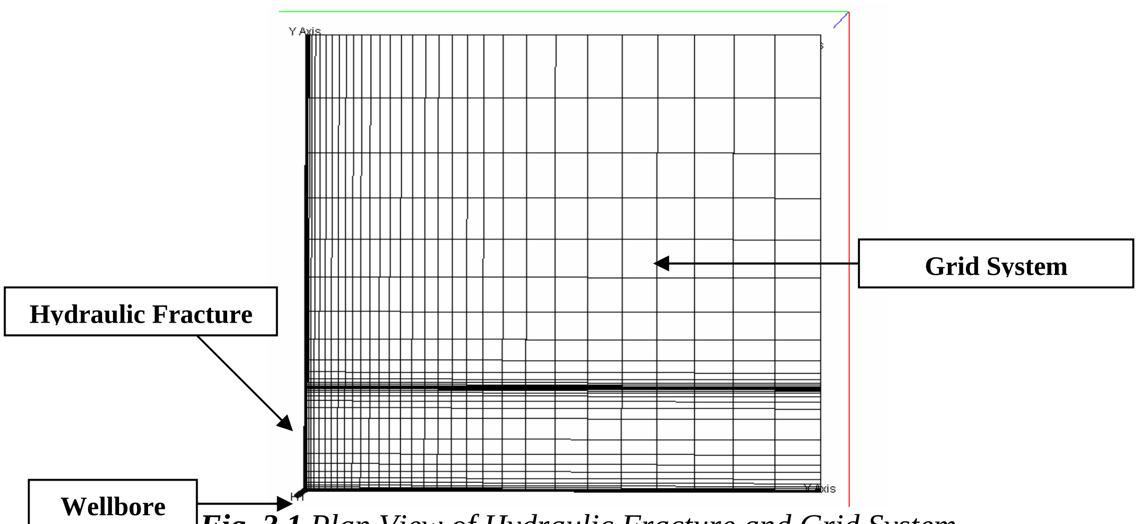

Fig. 3.1 *Plan View of Hydraulic Fracture and Grid System*

3.4 Reservoir Modeling

For efficiency, only a quarter of the drainage area was modeled using Eclipse (a finite-difference simulator) as shown in Fig 3.1. The well was assumed to be perforated and completed throughout the entire reservoir thickness. To model the pressure drop correctly, the cell lengths were varied in such a way that small values were assigned to cells near the wellbore and fracture tip. Different cell lengths were also assigned to the model depending on the fracture half-length. The selected grid and time steps were selected on the basis of sensitivity analyses to determine accuracy of the simulations.

Small time steps (e.g. one day to one month) depending on the simulation case were kept constant to maintain numerical accuracy.

3.5 Reservoir Model Validation

For reservoir model validation, three single-layer reservoir model cases were constructed with the general properties, as shown in Table 3.1, and the selected grid (40x35x1) used in the three case scenarios. Each model in the validation process also has a different fracture half-length (e.g. 180 ft, 350 ft, 600 ft) used in the case scenarios. Runs were made, and the synthetic production data were gathered and analyzed to back calculate the reservoir properties by using a production history matching procedure. The characteristics of the reservoir models are as follows:

(a) A single-layer, single-well case with a fracture half-length of 180 ft, and an effective permeability to gas of 0.01 md.

(b) A single-layer, single-well case with a fracture half-length of 350 ft, and an effective permeability to gas of 0.01 md.

(c) A single-layer, single-well case with a fracture half-length of 600 ft, and an effective permeability to gas of 0.01 md.

Since the time required for the pressure transient in radial flow to reach the boundaries in a reservoir as described above is approximately 13 years as, calculated using Eq 3.1, the reservoir simulation for each validation case was run for 15 years to obtain estimates of reservoir properties. Figs. 3.2-3.7 show a good history match for the synthetic cumulative production as well as the flow rate for every case. The reservoir properties estimated by the matches correspond to the input data used in the simulations.

$$t_s = \frac{948\phi\mu_g c_t r_e^2}{k_g} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.1$$

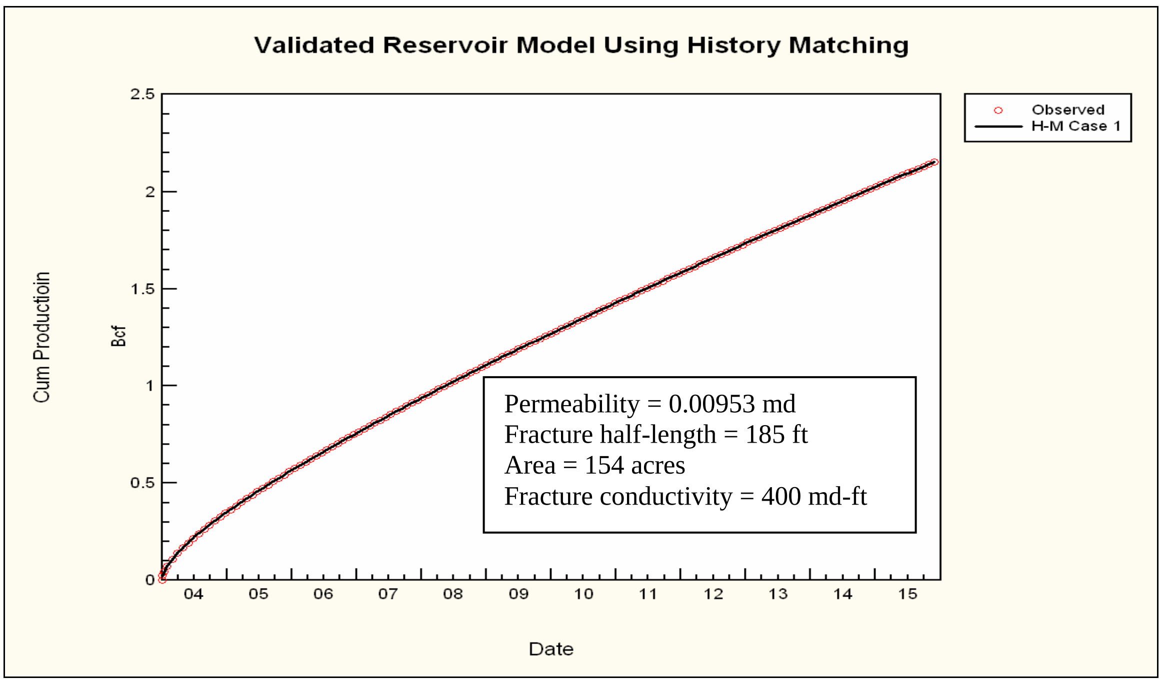

Fig. 3.2 *History Match Plot of the Cum Production for Reservoir Model Case (a)*

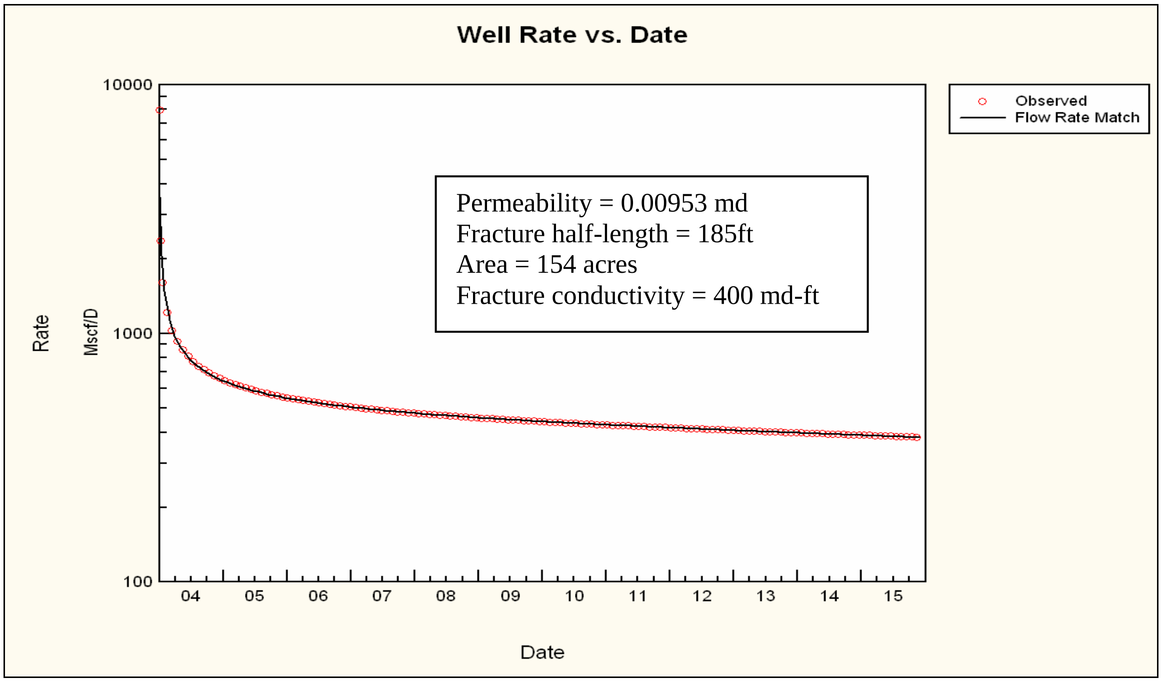

Fig. 3.3 *History Match Plot of the Flow Rate for Reservoir Model Case (a)*

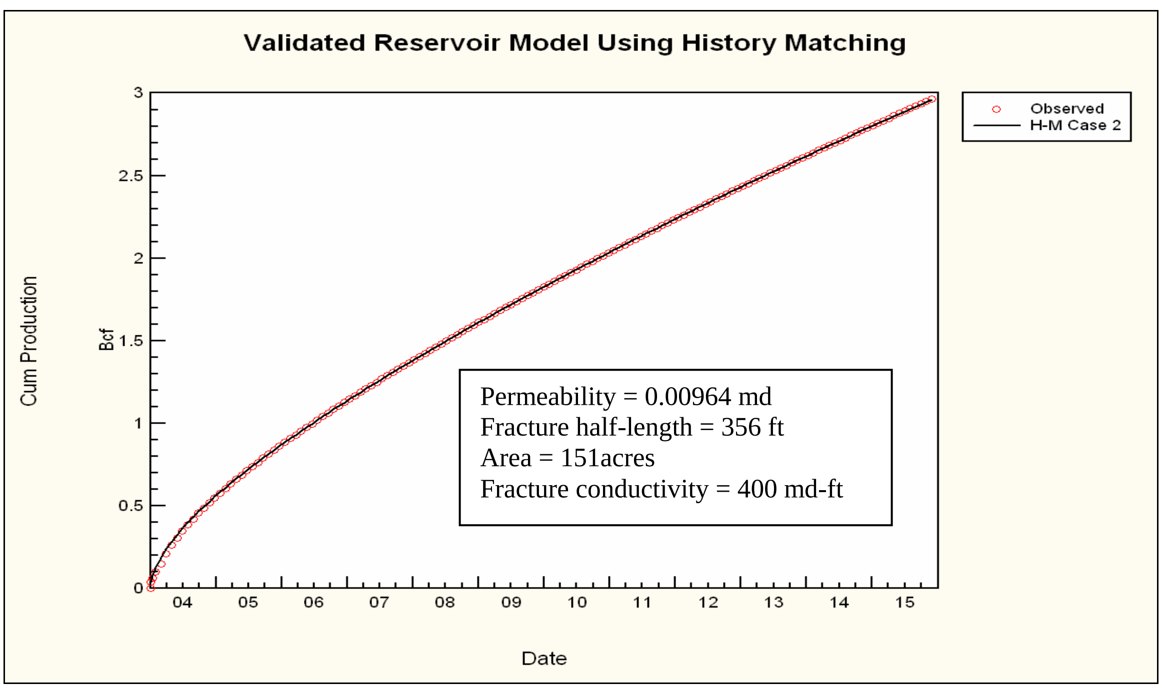

Fig. 3.4 *History Match Plot of the Cum Production for Reservoir Model Case (b)*

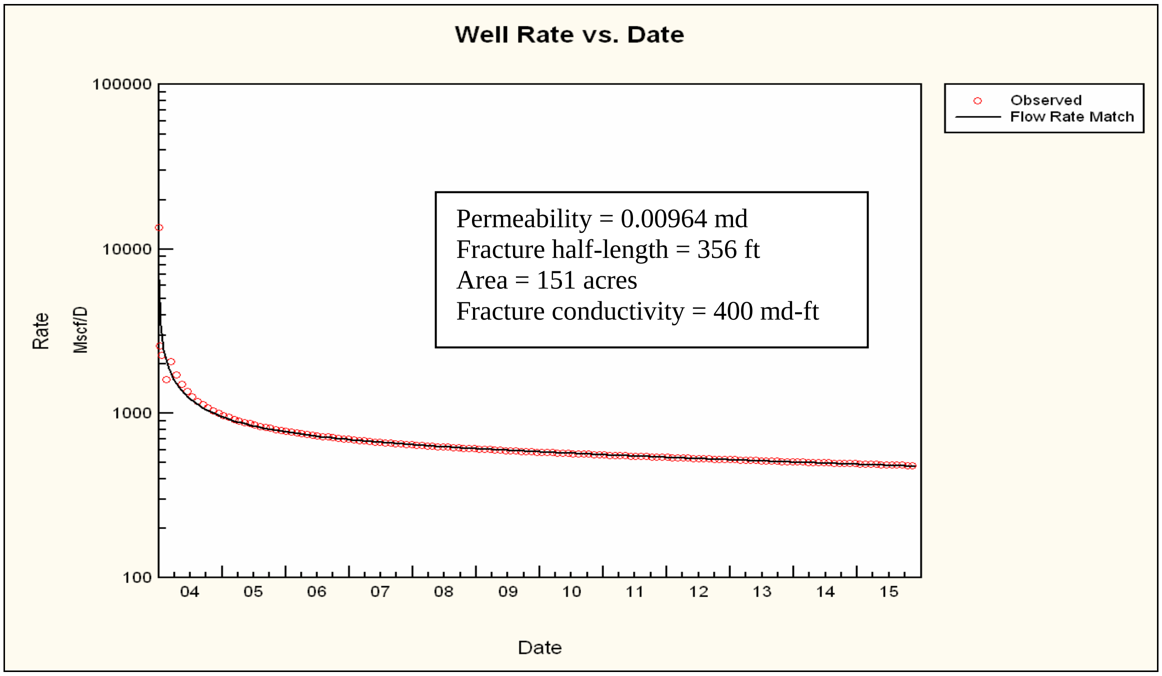

Fig. 3.5 *History Match Plot of the Flow Rate for Reservoir Model Case (b)*

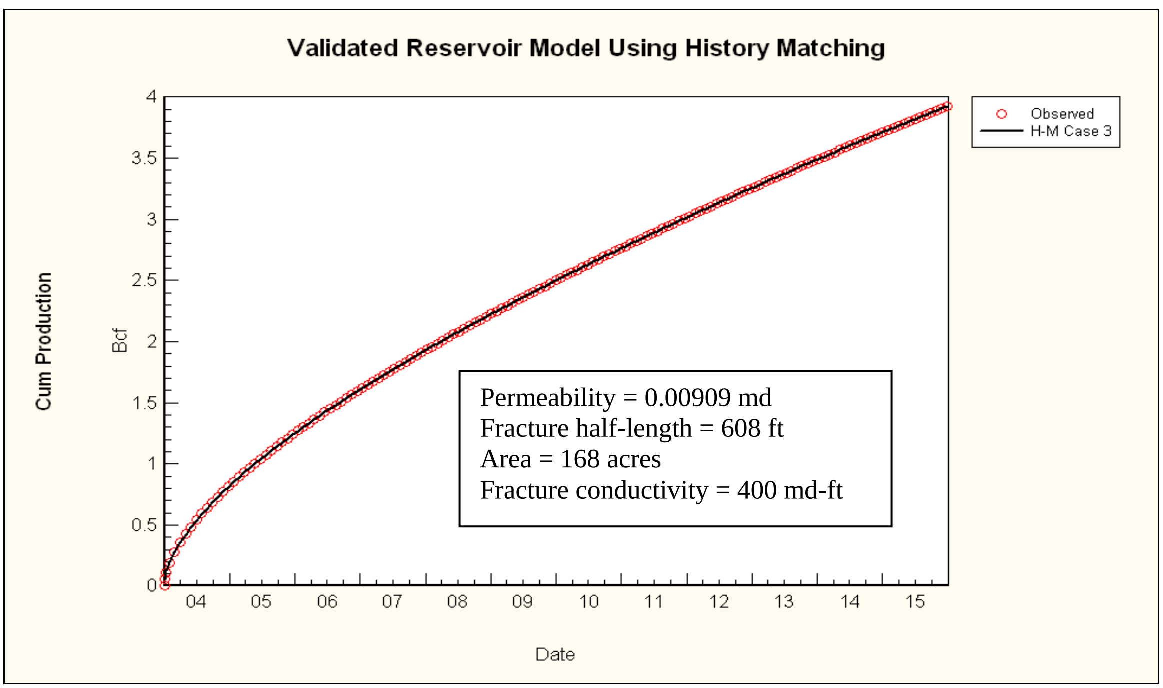

Fig. 3.6 *History Match Plot of the Cum Production for Reservoir Model Case (c)*

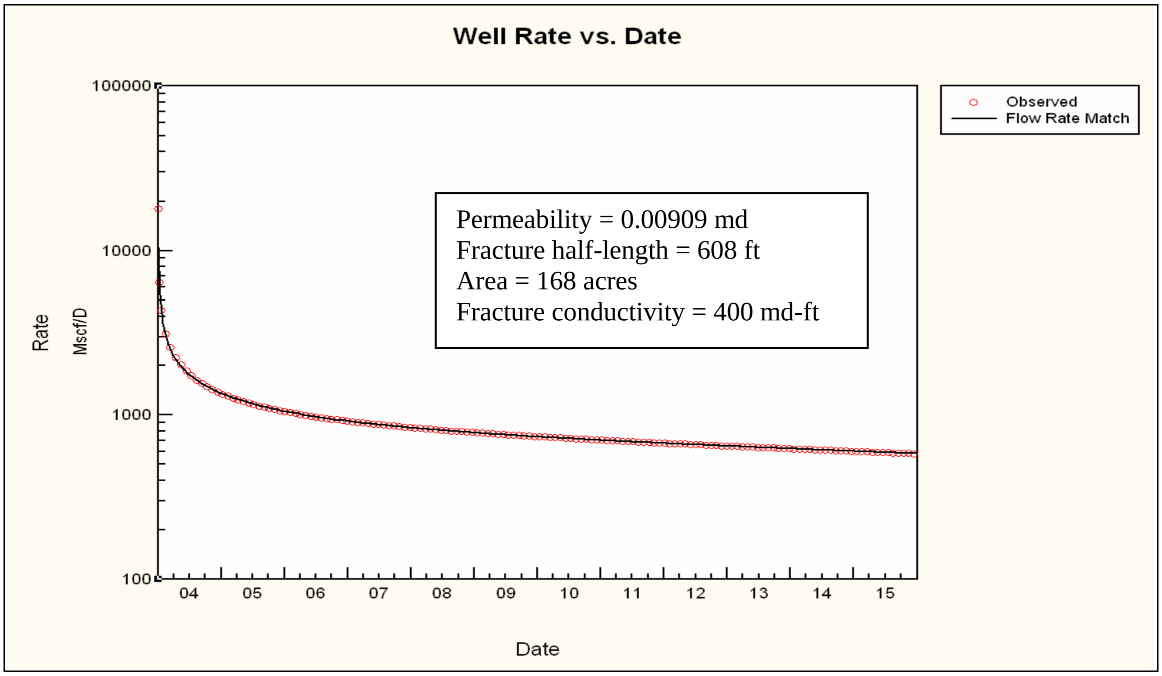

Fig. 3.7 *History Match Plot of the Flow Rate for Reservoir Model Case (c)*

3.6 Simulation Runs

Three main scenarios that truly describe a tight gas reservoir[33] were considered for the simulation runs; and they are as follows:

(1) A two-layer reservoir model with the same drainage area for both layers as shown in Fig. 3.8. The bottom layer is a low permeability interval that contains a significant amount of gas in place and is overlaid by a thin layer with a medium or high permeability streak depending on the run case.

(2) A two-layer reservoir model with a large, thick, low permeability layer at the bottom overlaid by a smaller, thinner, higher permeability streak as shown in Fig. 3.9.

(3) A three-layer reservoir model with the same drainage area for the top and bottom layers and a layer with smaller drainage area in the middle as shown in Fig. 3.10**.** The bottom and top layers present a low and a medium permeability values respectively, however, the bottom layer is a thick interval that contains significant amounts of gas in place. The middle layer is a thin high permeability streak that has a limited areal extension.

Different initial fracture half-lengths *(*L_f*)*, time of well production, and permeability values *(k)* for the upper layers were used depending upon the case being simulated.

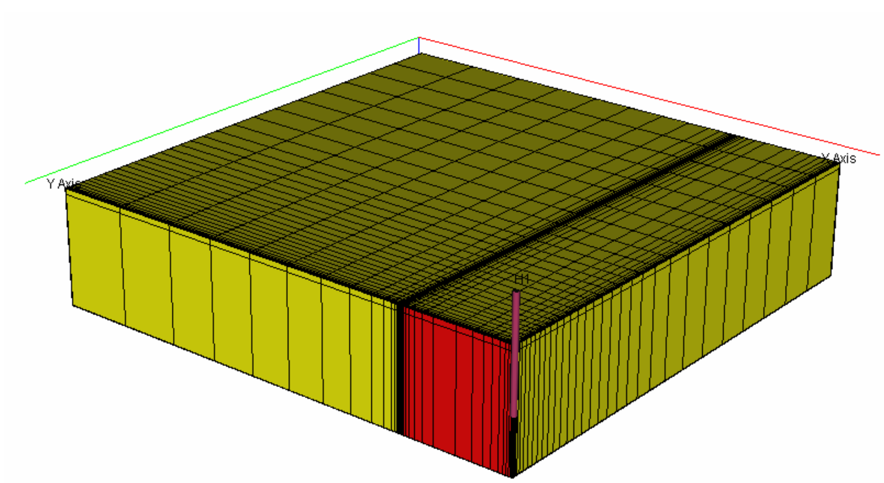

Fig. 3.8 *Synthetic Two-layer Reservoir Model Sketch (Same Drainage Area)*

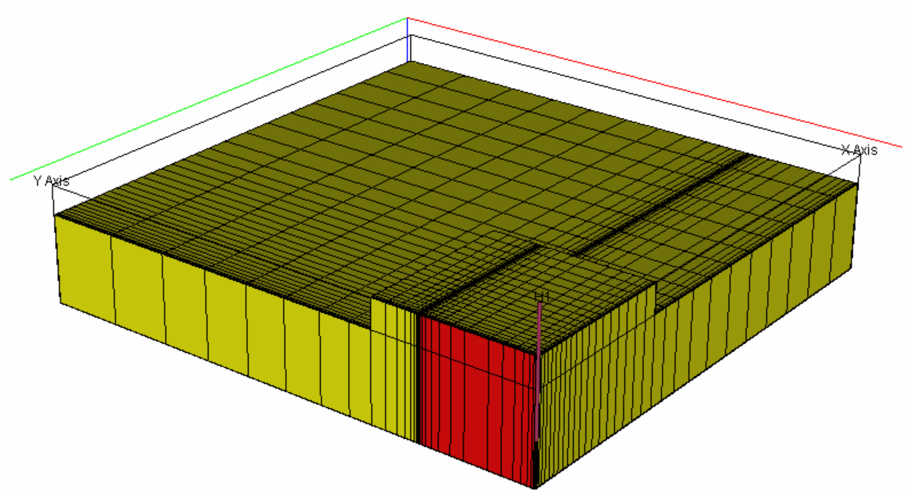

Fig. 3.9 *Synthetic Two-layer Reservoir Model Sketch (Different Drainage Area)*

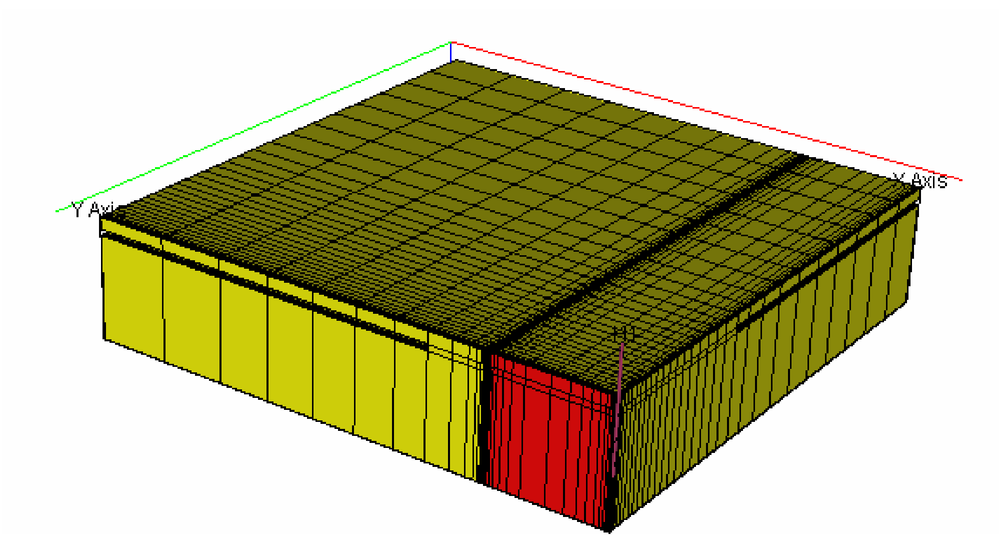

Fig. 3.10 *Synthetic Three-layer Reservoir Model Sketch*

3.6.1 Scenario One: Simulation Cases

Scenario one is a two-layer tight gas reservoir model, as shown Fig. 3.8**,** with the same drainage area for both layers, but different layer thickness and reservoir properties. The layer thickness for the top layer is 5 ft and for the bottom layer is 95 ft; the total net pay for the reservoir is 100 ft. Fig. 3.11 and Table A.1 summarize the runs made and data that were varied for the simulation cases in scenario one.

3.6.2 Scenario Two : Simulation Cases

Scenario two of the simulations is a two-layer tight gas reservoir model, as shown in Fig. 3.9**,** with different drainage area, net thickness, and reservoir properties for each layer. The net thickness for the top layer of the reservoir is 10 ft and 90 ft for the bottom layer; the total net pay thickness of the reservoir is 100 ft. Fig. 3.12 and Table A.2 summarize the data that were varied during these simulation cases.

3.6.3 Scenario Three : Simulation Cases

Scenario three of the simulations is a three-layer tight gas reservoir model, as shown in Fig. 3.10. The top and bottom layers present a drainage area of the same magnitude while the middle layer presents a smaller drainage area with a high permeability value. The net thickness for the top layer of the reservoir is 10 ft, for the middle layer is 5 ft, and for the bottom layer is 85 ft; the total net pay thickness of the reservoir is 100 ft. Fig. 3.13 and Table A.3 summarize the data that were varied during these simulation cases.

In all these scenarios, most of the gas in place is located in the thick, low permeability layer. However, the initial flow rates of these scenarios were often dominated by the thin, higher permeability layers that contained only a small fraction of the gas in place.

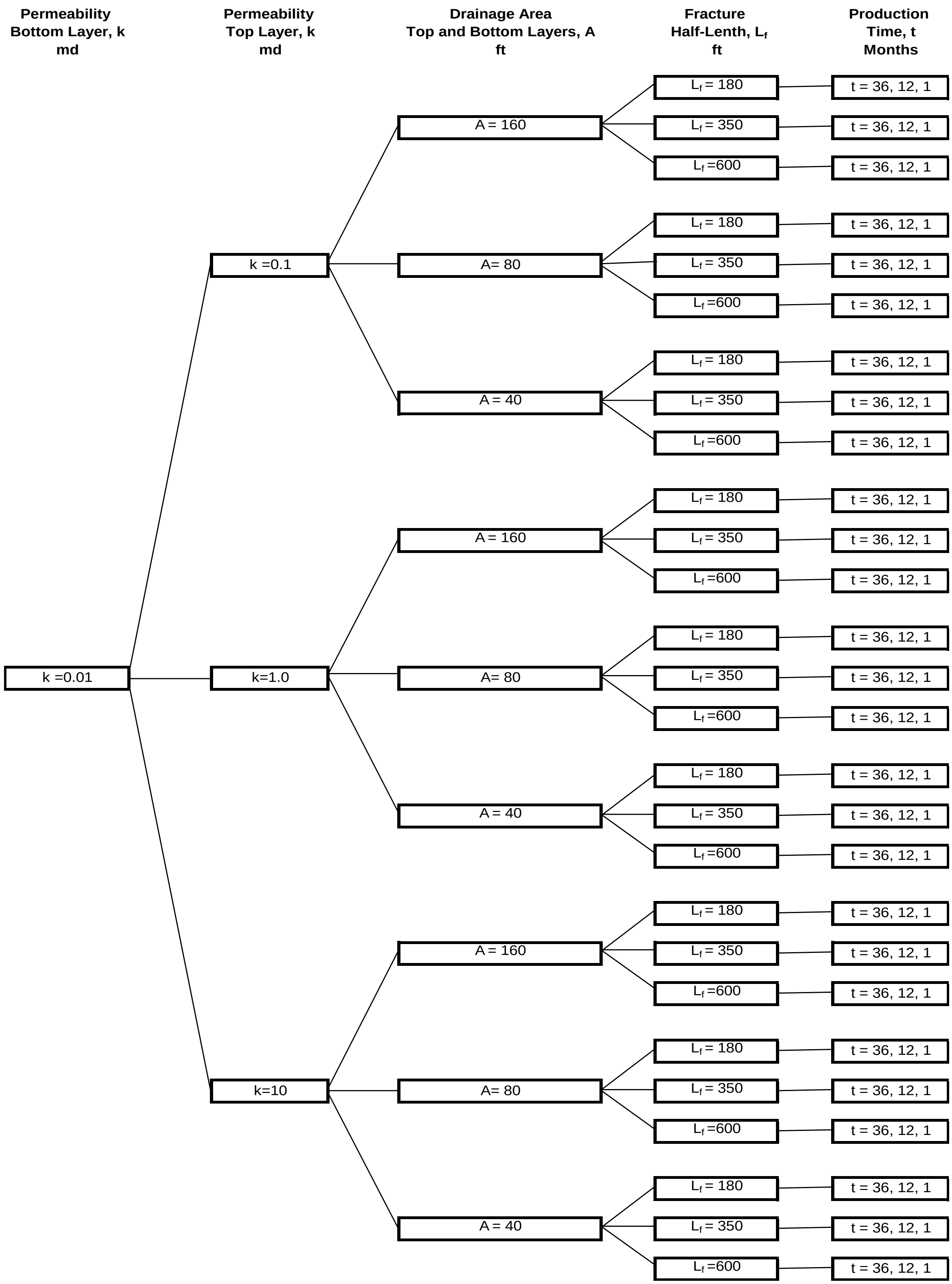

Fig. 3.11 *Schematic Representation of Simulation Runs for Case Scenario One*

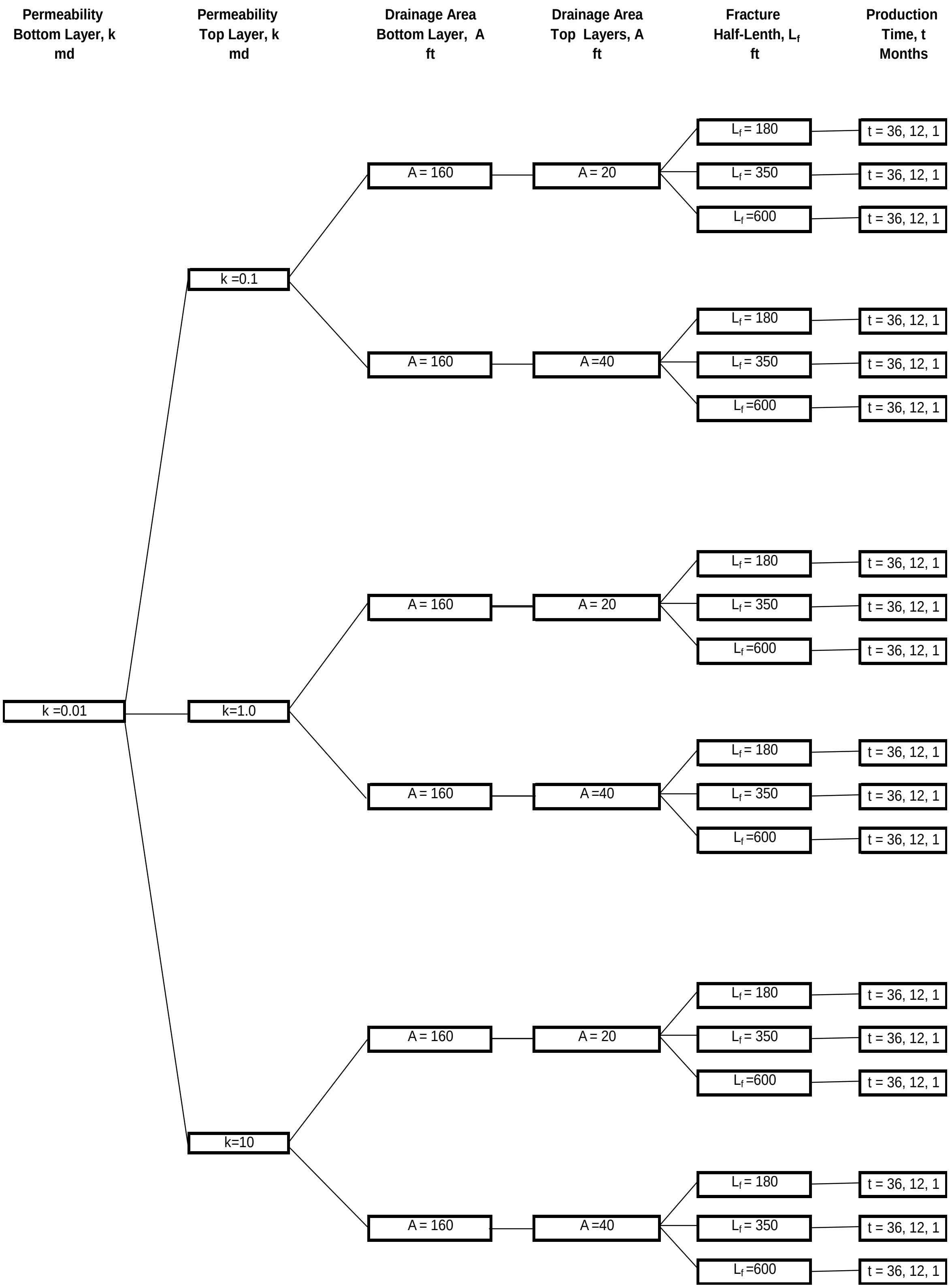

Fig. 3.12 *Schematic Representation of Simulation Runs for Case Scenario Two*

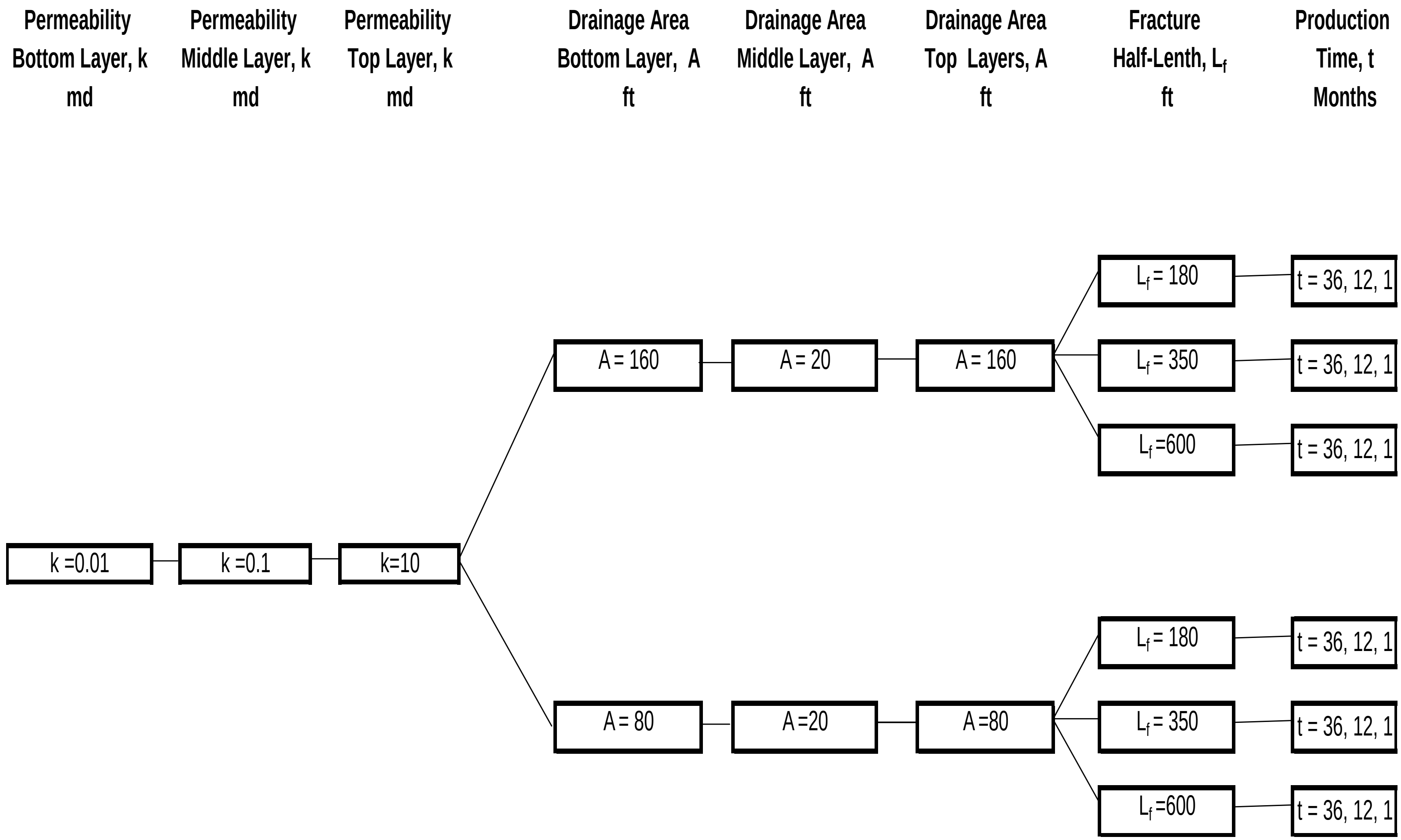

Fig. 3.13 *Schematic Representation of Simulation Runs for Case Scenario Three*

3.7 Production Data Analysis

PMTx version 1.0, a single-well analytical simulator, was used to history match the production data from scenario one through three generated using the numerical simulator (Eclipse). One month, one year, and three years of production data for each scenario were used in the history match analysis to obtain values of permeability-thickness product, fracture half-length, and drainage area of the well. Analytical solutions for a single-layer, hydraulically fractured, finite acting, isotropic, and single porosity reservoir were used in the production history analysis.

Forecasts for ten years of cumulative production were made using the one layer model results from the analyses of one month, one year, and three years of production data and using different drainage areas. The error in these forecasts was also determined and analyzed for all the cases according to the different amount of production data used to calculate the reservoir properties. Therefore, this research study revealed the typical errors in production forecast estimation in tight gas reservoirs when reservoir properties in these heterogeneous reservoirs are estimated by history matching the production data using single-layer model descriptions, and then these erroneous values of reservoir properties are used to forecast gas reserves.

CHAPTER IV

PRODUCTION HISTORY MATCHING AND PRODUCTION FORECASTING ANALYSES

4.1 Introduction

This chapter contains the simulation data for the different scenarios described in chapter III with their respective production history match analysis. Due to the large number of runs for every simulation scenario, only a few cases for each scenario are going to be explained in this chapter. Graphs and tables for all the runs can be found in the appendices. The simulation data were history matched on cumulative production using the model described in Section 3.7. Open circles were used to represent the observed production data and a solid line was used to represent the production data match.

Reserve forecasts using the reservoir properties calculated from the history matches were also graphed to demonstrate the error that occurs when single-layer modeling methods are used to history match production data and to forecast reserves in typical layered tight gas reservoirs. Two different forecasts for ten years of cumulative gas production were plotted for each case run. **Forecast (1)** is a forecast using all the reservoir properties calculated from the history match analysis including the estimate of drainage area. **Forecast (2)** is a forecast using the permeability (*k*) and fracture half-length (L_f) obtained from the match, plus the real drainage area (*A*) of the reservoir. The real area is the well spacing assuming a blanket tight gas reservoir. The error of these forecasts vs. amount of production data used in the history match was also analyzed. The results of the history match analysis for every case are summarized in tables.

4.2 Scenario One: Simulation Results

4.2.1 Production History = 36 months

Case No 10 is for Scenario one which is a two-layer reservoir where both the high permeability layer and the low permeability layer have the same drainage area. Table 4.1 shows the reservoir data for simulation case No 10.

Table 4.1 *Reservoir Data for Simulation Case No 10*

Case N_o	10
$k_{(Top\ Layer)}$, md	0.1
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	1.45
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

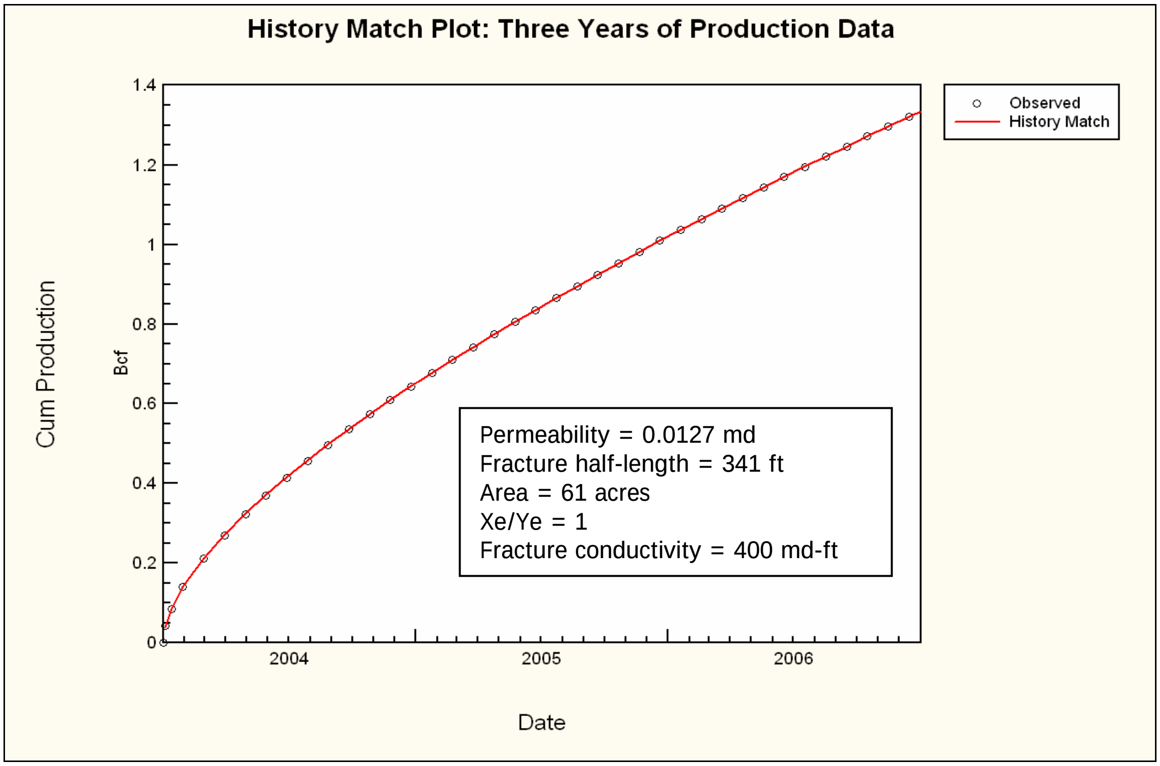

Fig. 4.1 *History Match Plot of the Cum Production for Reservoir Model Case No 10*

Fig. 4.1 displays the production history match for simulation case No 10 from Table A.1. The plot shows an excellent match for 3 years of production history. The permeability-thickness product (*kh= 1.27md-ft*) falls within ± 15% error of the input value (*kh= 1.45md-ft*) used in the simulation model. For fracture half-length (L_f), the matched value presents a reasonable agreement with the true value of L_f falling within ± 3 % error. The area calculated by the history match was underestimated by a factor of 2.6, because the pressure transient had not yet felt the boundary of the reservoir in the low permeability layer that contains most of the gas in place. Of more production data were used in the history match analysis, the estimated value of the drainage area would increase as the well production is affected by more of the reservoir.

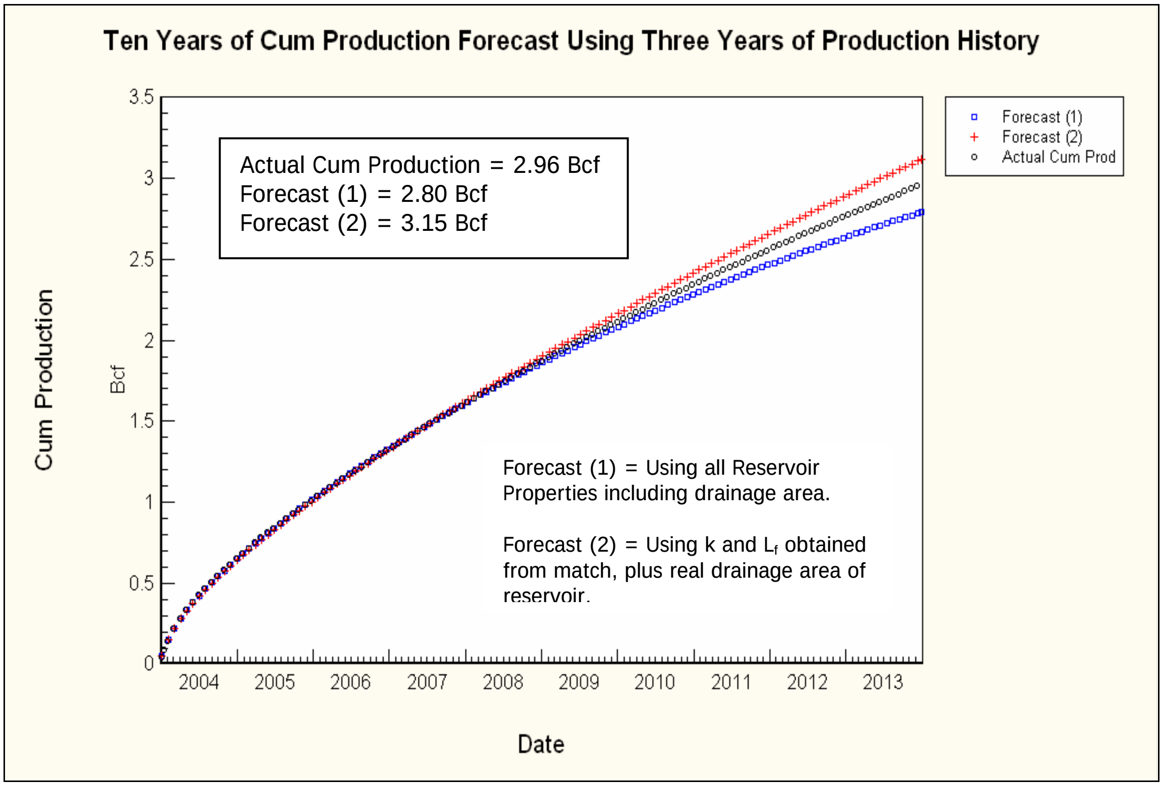

Fig. 4.2 *Cumulative Gas Forecast for Case No 10*

Fig. 4.2 is a plot of the reserves forecasts estimated with the reservoir properties calculated in case No 10. Both Forecasts (1) and (2) represent reasonable gas estimates of 10 years of cumulative gas production falling within ± 10 % error with respect to the actual cumulative production of the simulation model.

Table 4.2 *Reservoir Data for Simulation Case No 11*

Case N_o	11
$k_{(Top\ Layer)}$, md	1.0
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	5.95
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

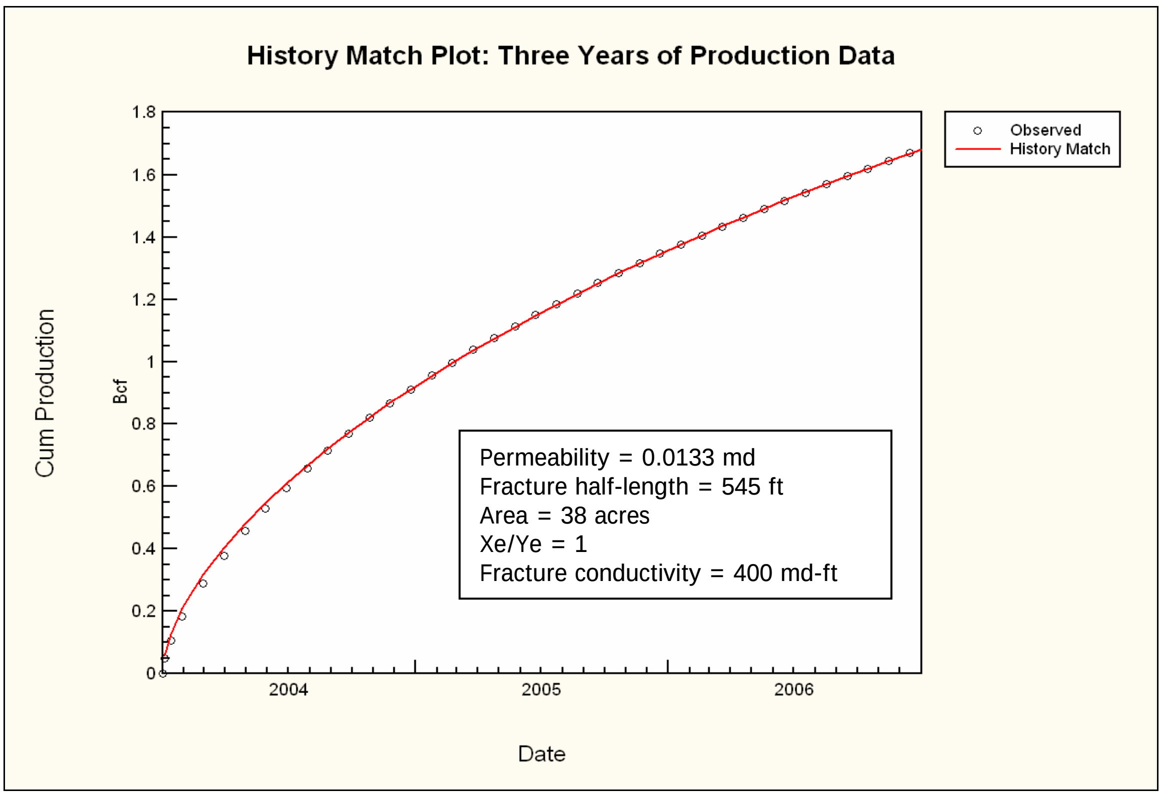

Fig. 4.3 *History Match Plot of the Cum Production for Reservoir Model Case No 11*

Fig. 4.3 exhibits the production history match for simulation case No 11 from Table A.1. Case No 11 is the same as case No 10 except the permeability in the top layer is 1.0 md vs. 0.1 md in case No 10, as shown in Table 4.2. The plot shows an overall fair match for 3 years of production history; however, the permeability-thickness product estimated by the history match (*kh= 1.33md-ft*) was underestimated and resulted in an error of -78 % with respect to the permeability thickness product (*kh= 5.95md-ft*) used in the simulation model. The history match resulted in a fracture half-length (L_f) estimate of 545 ft which is a + 56% error from the true fracture half-length (350 ft) in the simulation model. The area calculated by the history match was underestimated by a factor of 4.2. The underestimation of the drainage area of the well is caused again by the fact that in three years the well did not reach pseudo-steady flow. However, it is important to notice that with the same amount of production history, the factor of underestimation in the drainage area increased as the permeability contrast within the layers increase.

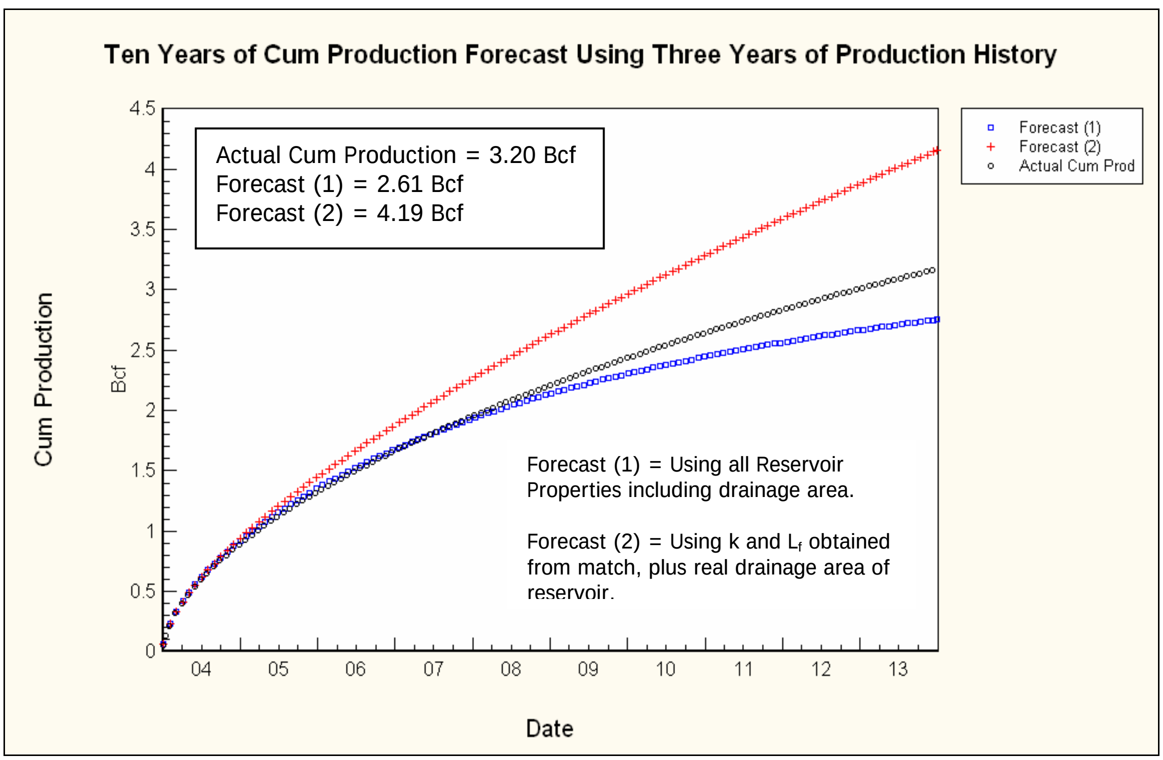

Fig. 4.4 *Cumulative Gas Forecast for Case No 11*

Fig. 4.4 displays the reserves forecasts from simulation case No 11. Forecast (1) was underestimated with an error of –18 % while Forecast (2) was overestimated with an error of 31%. Forecast (1) was low because the drainage area estimated from the PDA was too small. Forecast (2) was too high because the average k used in the single layer model was too large. This result is similar to the predictions made by Gatens and Lee.[35]

Table 4.3 *Reservoir Data for Simulation Case No 12*

Case N_o	12
$k_{(Top\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	50.95
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

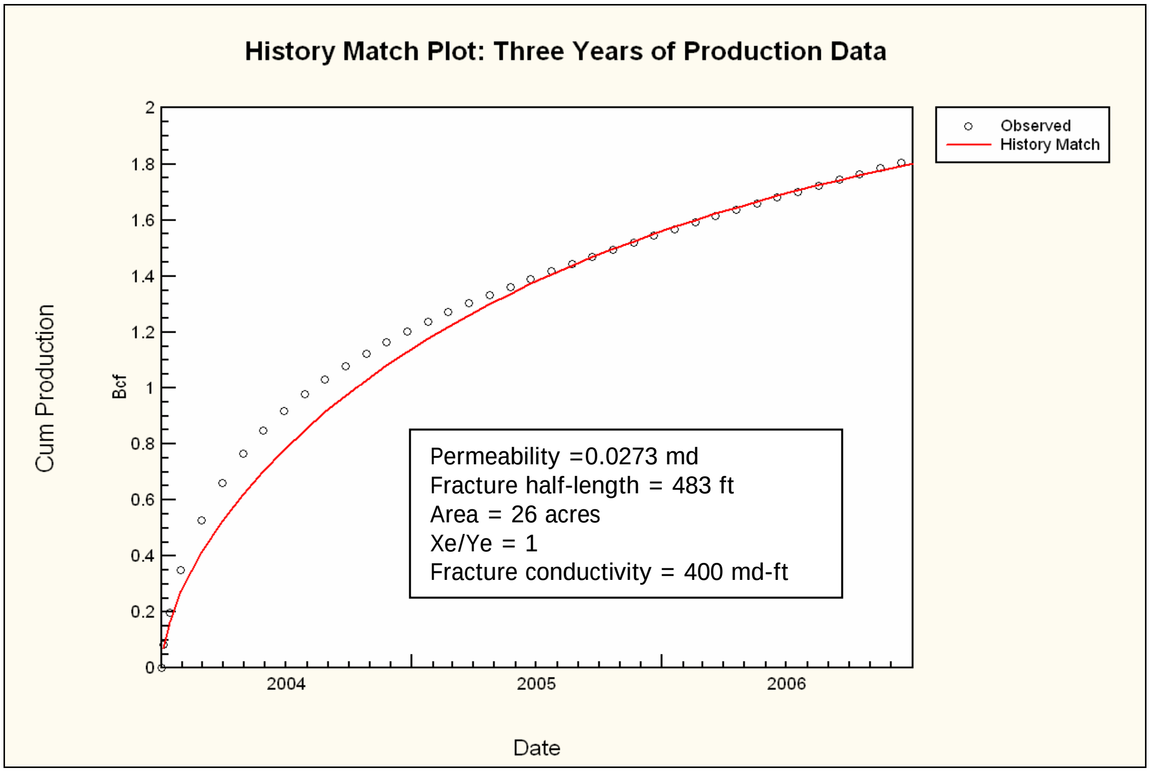

Fig. 4.5 *History Match Plot of the Cum Production for Reservoir Model Case No 12*

Fig. 4.5 exhibits the production history match for simulation case No 12 from Table A.1. In this case, the permeability of the top zone is now 10 md, as shown in Table 4.3. The analytical model did not successfully match all the production data. To match the cumulative gas production after three years, the model underestimated the gas production during the first year. The early production does not match well due to the high gas production contribution of the high permeability layer that dominates the production during the first year. The production data start to match better at a later time when the high permeability layer is partially depleted and most of the gas production is coming from the low permeability interval. This "production curve shape" in the history match analysis can tell the reservoir engineer that the reservoir is indeed a multi-layer reservoir with a high degree of permeability contrast. The permeability-thickness product *(kh)* calculated by the history match was 2.73md-ft; however, it was underestimated by -95 % with respect to the true (simulated) permeability thickness product (*kh= 50.95md-ft*) used in the simulation model. The history match shows a fracture half-length (L_f) of 483 ft, which represents a + 38% error from the true fracture half-length (350 ft) of the simulation model. The area calculated by the history match was underestimated by a factor of 6.2 (26 acres vs. 160 acres).

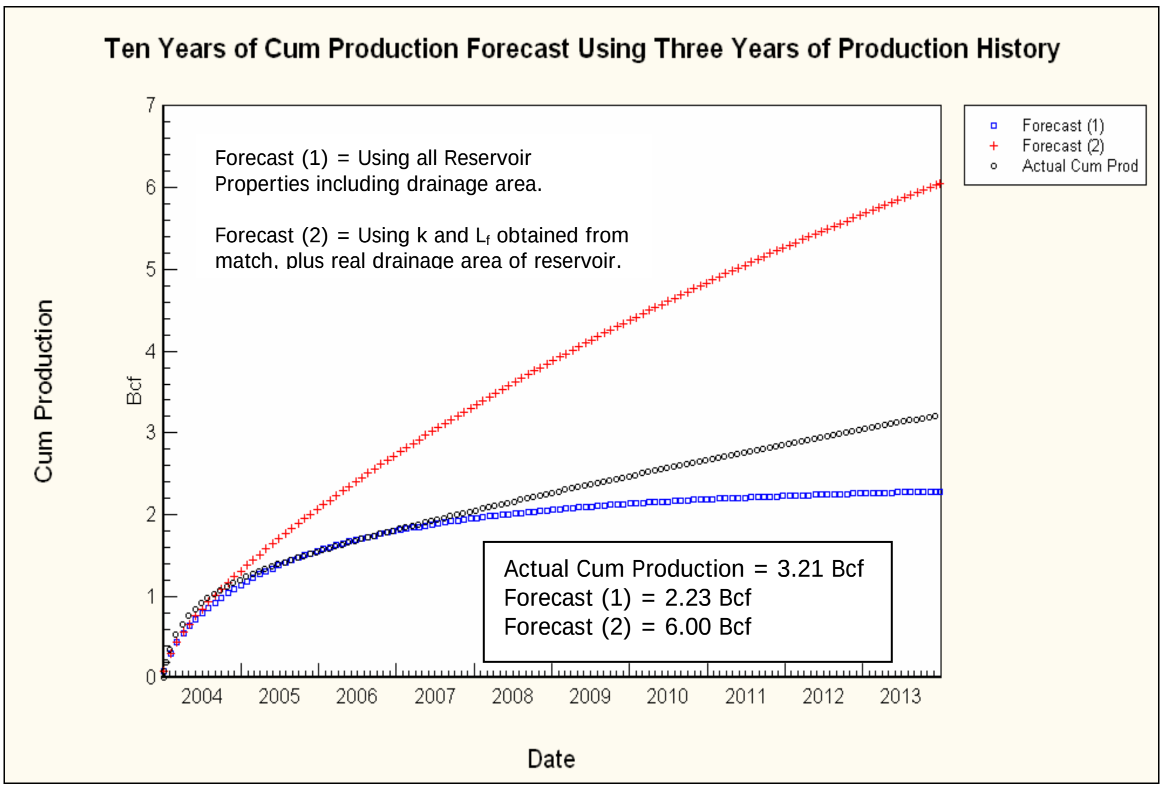

Fig. 4.6 *Cumulative Gas Forecast for Case No 12*

Fig 4.6 shows the cumulative production forecast for 10 years with the calculated reservoir properties from simulation case No 12. Forecast (1) has an underestimation error of -30% and Forecast (2) has an overestimation error of 87%.

In cases like case No 12, the production data could not be matched because the production decline varied drastically with time, declining faster in the early time due to the large contribution of gas production of the high permeability layer to the system and decreasing with time as the high permeability layer depletes and the production starts to be dominated by the lower permeability layer. For case No 12, it was found that all the production data could be matched better by varying the geometry of the reservoir or aspect ratio (Xe/Ye). The data used to describe case No 12 was generated using a square drainage area and 2-layers. The “shape” of the production decline curve could not be matched using a single layer, square reservoir. However, if we changed the shape from a square to a rectangle, we found that we could match all three years of production data almost perfectly. Such a match is illustrated in Fig. 4.7

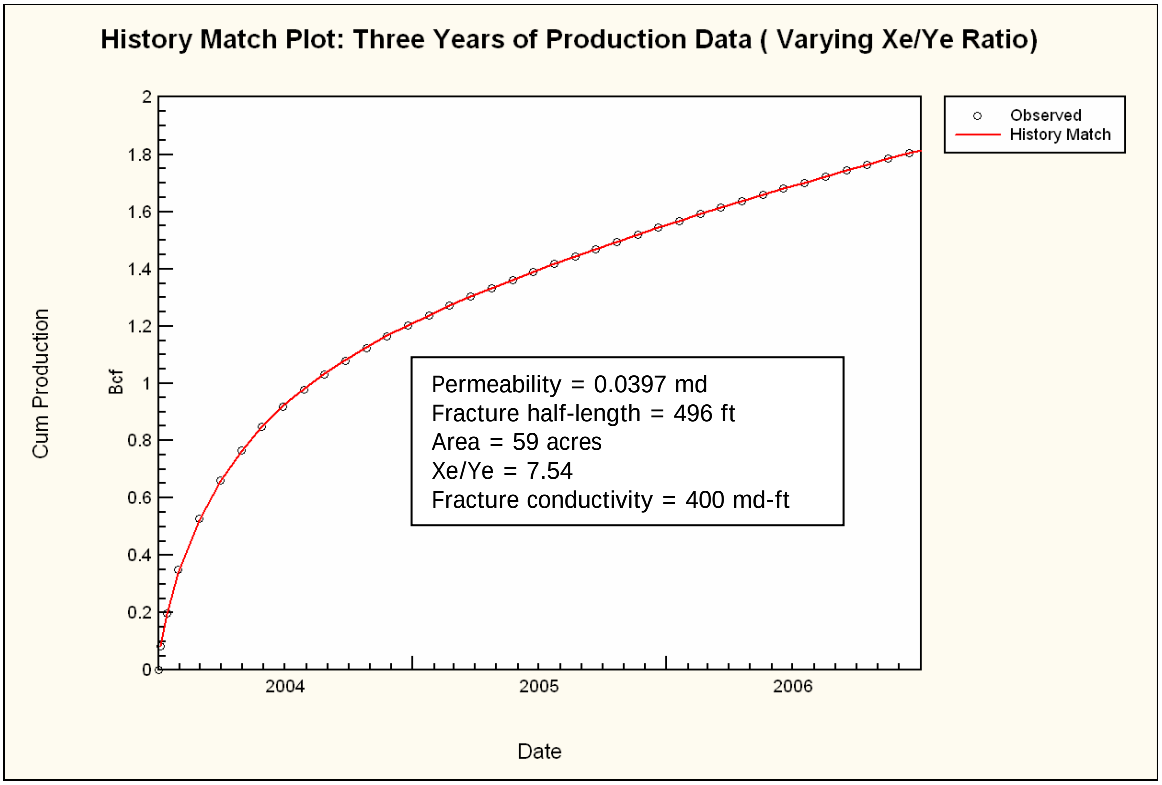

Fig. 4.7 *History Match Plot of the Cum Production for Reservoir Model Case No 12, Varying the Aspect Ratio*

Fig. 4.7 portrays a perfect match of the previous simulation case No 12 by varying the geometry of the drainage area of the well from a square to a rectangular geometry by an aspect ratio (*Xe/Ye*) of 7.54. Although Fig. 4.7 indicates it is a perfect match for the production data for 3 years, the geometry description of the reservoir is bogus and the reservoir properties values are incorrect. This example illustrates how non-unique the PDA problem can be and how important it is to describe the reservoir as completely as feasible prior to setting up a model to analyze production data in such reservoirs.

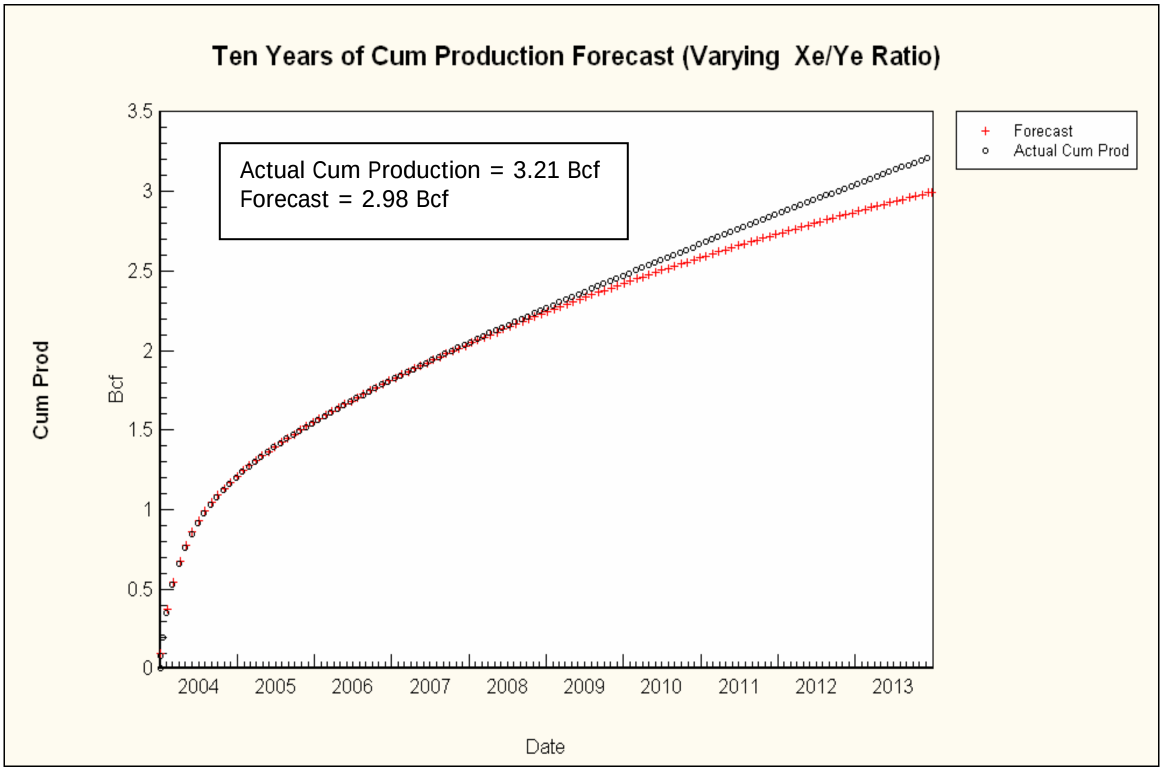

Fig. 4.8 *Cumulative Gas Forecast for Case No 12, Varying the Aspect Ratio*

Fig. 4.8 illustrates the reservoir forecast for case No12, changing the geometry of the drainage area. The ten year production forecast falls within the ± 10% of the actual cumulative production; yet the results of the history match analysis do not describe the real reservoir shape and properties. The reason that the reserves forecast is acceptable for this case is because the estimation of production forecast is largely dominated by the volume of gas in place of the low permeability layer in the reservoir. Therefore, the variation of the geometry of the reservoir model let the history match estimate a larger drainage area, and with the combination of this drainage area and the reservoir properties estimated by the mach gave the model more gas in place to be produced. In this case, two wrongs (the wrong number of layers and the wrong reservoir shape) resulted in an estimate of 10-year recovery that was fairly accurate. We do not expect this result to be generally true.

4.2.2 Production History = 12 months

Table 4.4 *Reservoir Data for Simulation Case No 13*

Case N_o	13
$k_{(Top\ Layer)}$, md	0.1
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	1.45
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

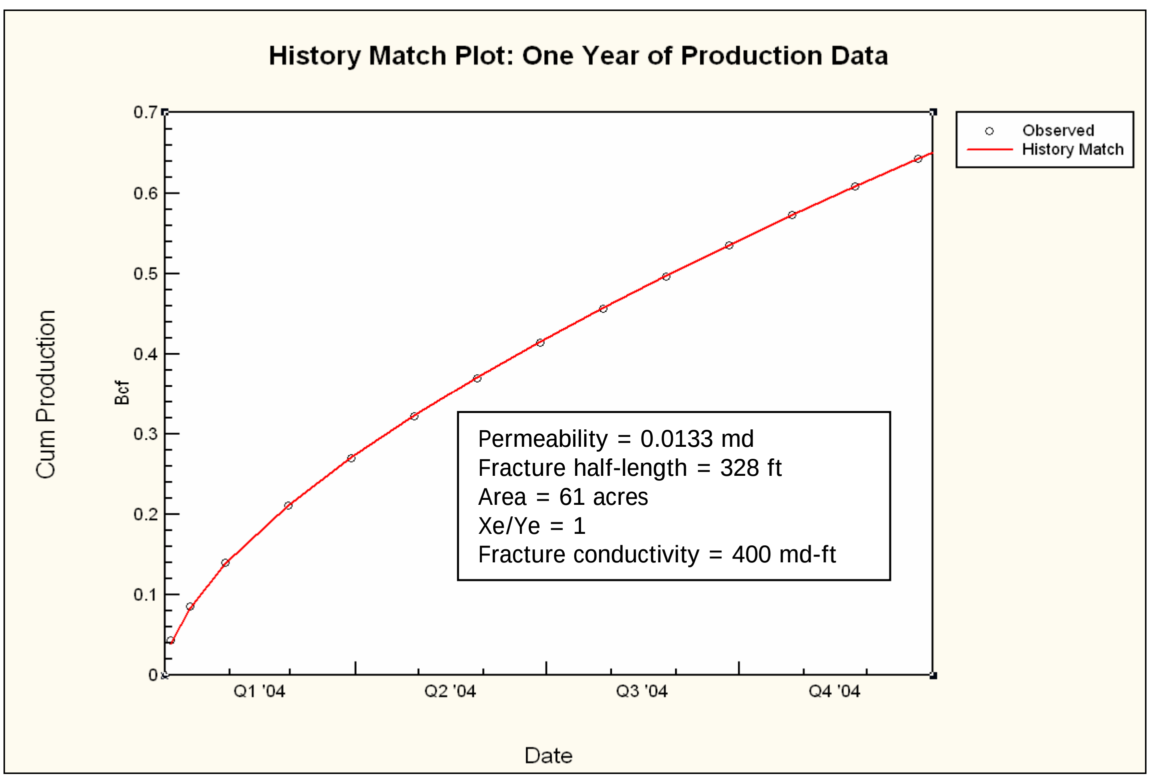

Fig. 4.9 *History Match Plot of the Cum Production for Reservoir Model Case No 13*

Fig. 4.9 presents the production history match for simulation case No 13 from Table A.1. Case No 13 is identical to case No 10 except now we are only analyzing one year of production data versus three years in case No 10, as shown in Table 4.4. The permeability-thickness product (*kh= 1.33md-ft*) falls within ± 15% error of the (*kh= 1.45md-ft*) input in the simulation model. The fracture half-length (L_f) predicted from the history match agrees reasonably with the value of the true L_f with an error of -6.0 %. The drainage area calculated by the history match was underestimated by a factor of 2.6 (61acres vs. 160 acres).

Comparing the amount of production data used to perform the production history matching analysis, three years of production history as shown in case No 10 do not make much difference in the accuracy of reservoir properties than one year of production history as shown in case No 13 when the permeability contrast within the layers is small.

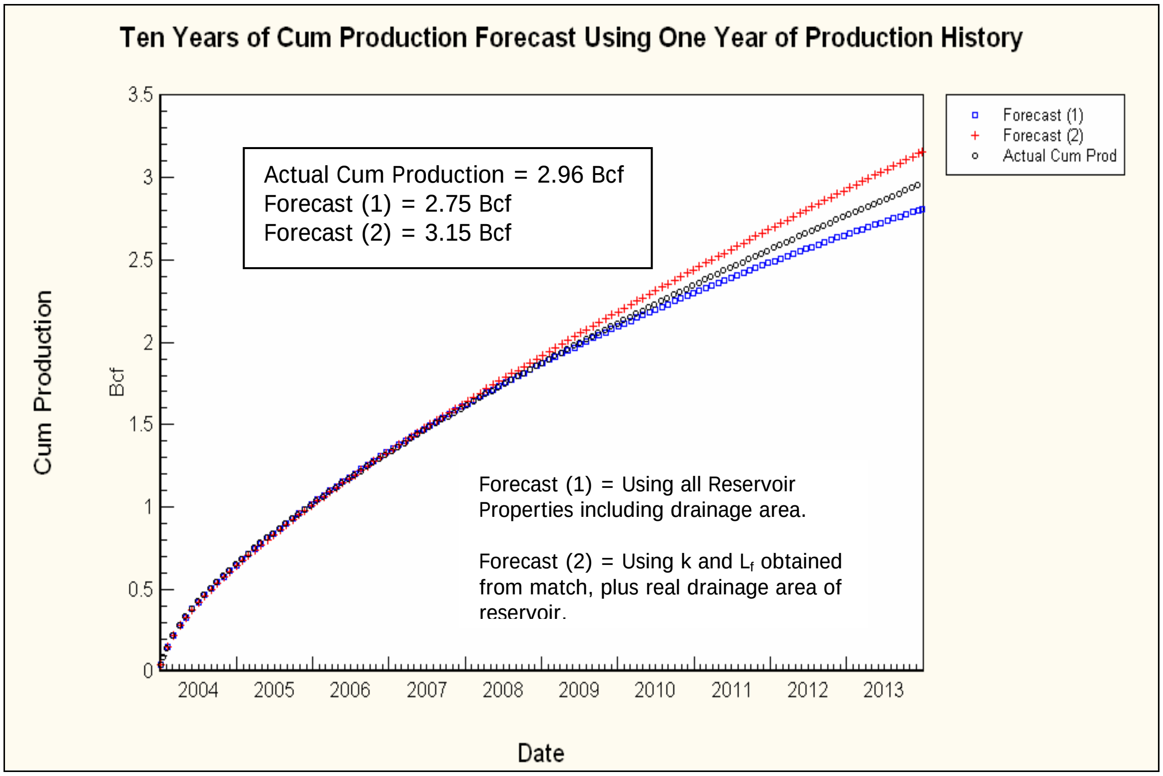

Fig. 4.10 *Cumulative Gas Forecast for Case No 13*

Fig. 4.10 shows an acceptable forecast for case No 13 falling within an error of ± 10% from the actual cumulative production of 10 years. Once again, it is important to mention that in tight gas reservoirs with small contrasts in reservoir properties, matching one year of production history will yield fair estimates of reservoir properties resulting also in reliable reserves forecasts.

***Table 4.5** Reservoir Data for Simulation Case No 14*

Case N_o	14
$k_{(Top\ Layer)}$, md	1.0
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	5.95
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

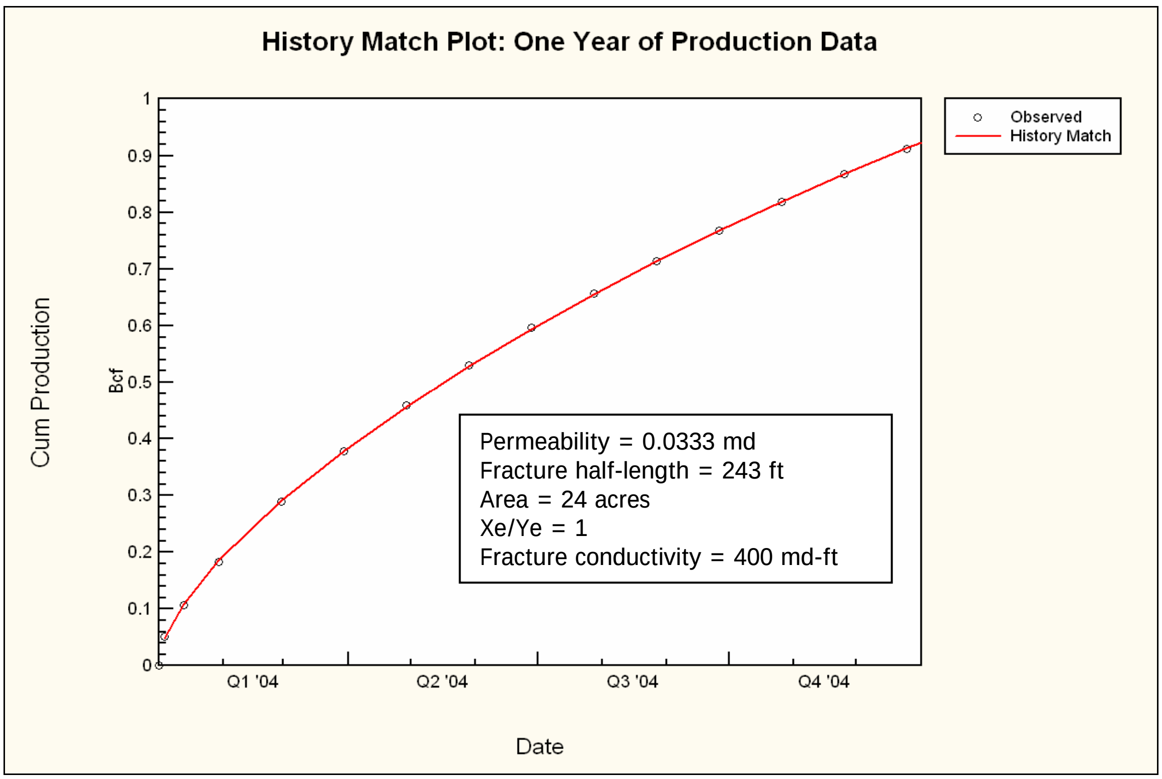

***Fig. 4.11** History Match Plot of the Cum Production for Reservoir Model Case No 14*

Case No 14 is identical to Case No 11 except we have only analyzed the first year of production data rather than the first three years. The permeability in the top layer is 1.0 md, as shown in Table 4.5. Fig. 4.11 shows the history match, which appears to be satisfactory. However, the results using the single-layer model to analyze early-time data generated using a two-layer model, do not accurately describe the true permeability-thickness product (*kh*) nor the true drainage area. The fracture half-length was underestimated by 1/3 of the fracture half-length used in the simulation. The kh was underestimated with an error of -44%. The drainage area was estimated to be 24 acres versus the true value of 160 acres. This example also demonstrates the uniqueness problems we face when trying to analyze short-term production data in layered, tight gas reservoirs.

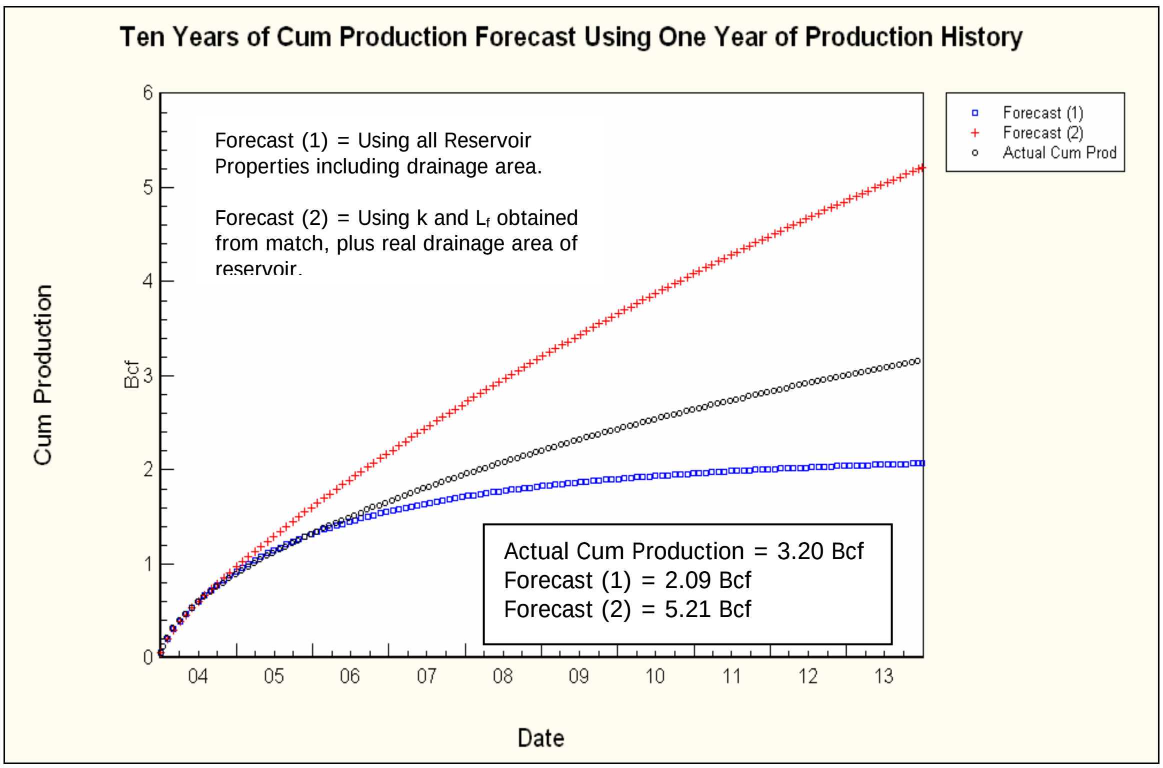

Fig 4.12 *Cumulative Gas Forecast for Case No 14*

Fig. 4.12 displays a plot of the reserves forecasts estimated with the reservoir properties from the perfect match from simulation case No 14. Neither forecasts (1) nor

(2) results in reasonable gas estimates of the 10 year cumulative gas production. For this example Forecast (1) was underestimated and has an error of -35% because the drainage area is too small while Forecast (2) was overestimated and has an error of + 63% because the value of permeability (*k*) is too large.

Table 4.6 *Reservoir Data for Simulation Case No 15*

Case N_o	15
$k_{(Top\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	50.95
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

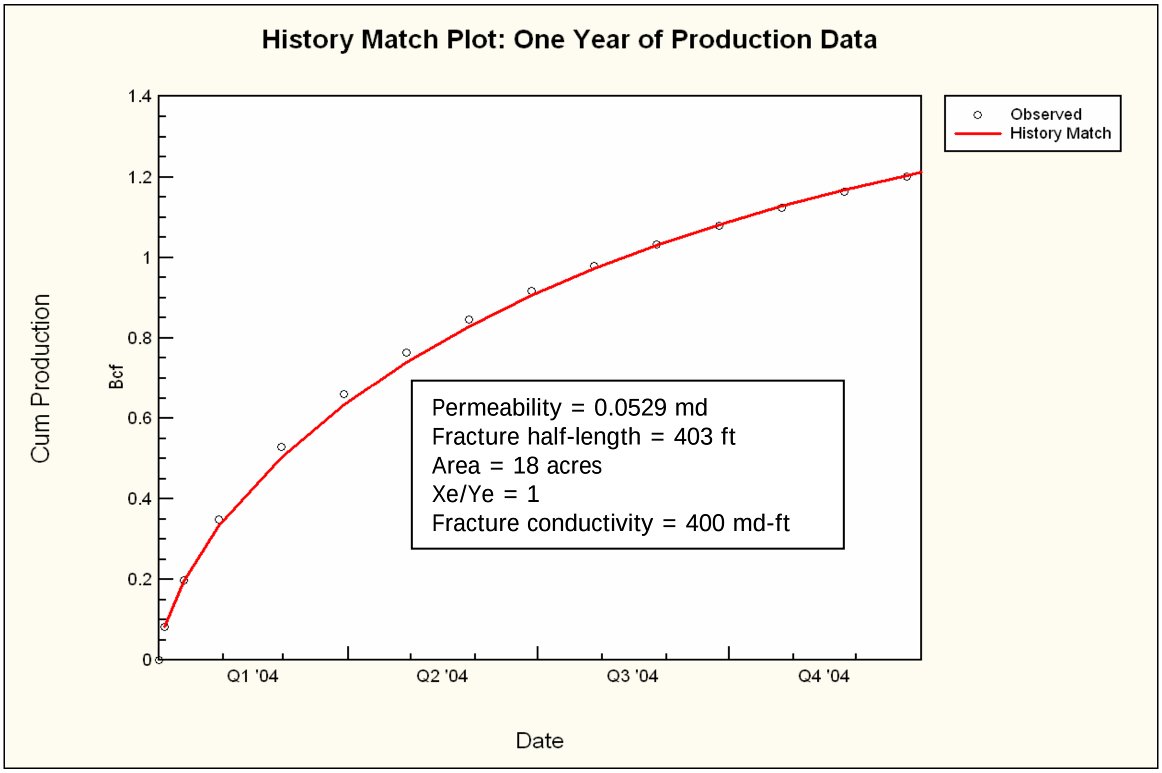

Fig 4.13 *History Match Plot of the Cum Production for Reservoir Model Case No 15*

Case No 15 is identical to case No 12 except we have only analyzed one year of production data. The permeability in the upper layer is 10 md, as shown in Table 4.6. The history match seems to be satisfactory, but the calculated results, shown in Fig. 4.13, are not very accurate. Once again, due to the high contribution of gas production from the high permeability interval during the first year, the analysis did not match data points in the first half of the year. However, this mismatch was not as bad as the mismatch from simulation case No 12. Also, the results from this match do not correspond to the input data used in the simulation.

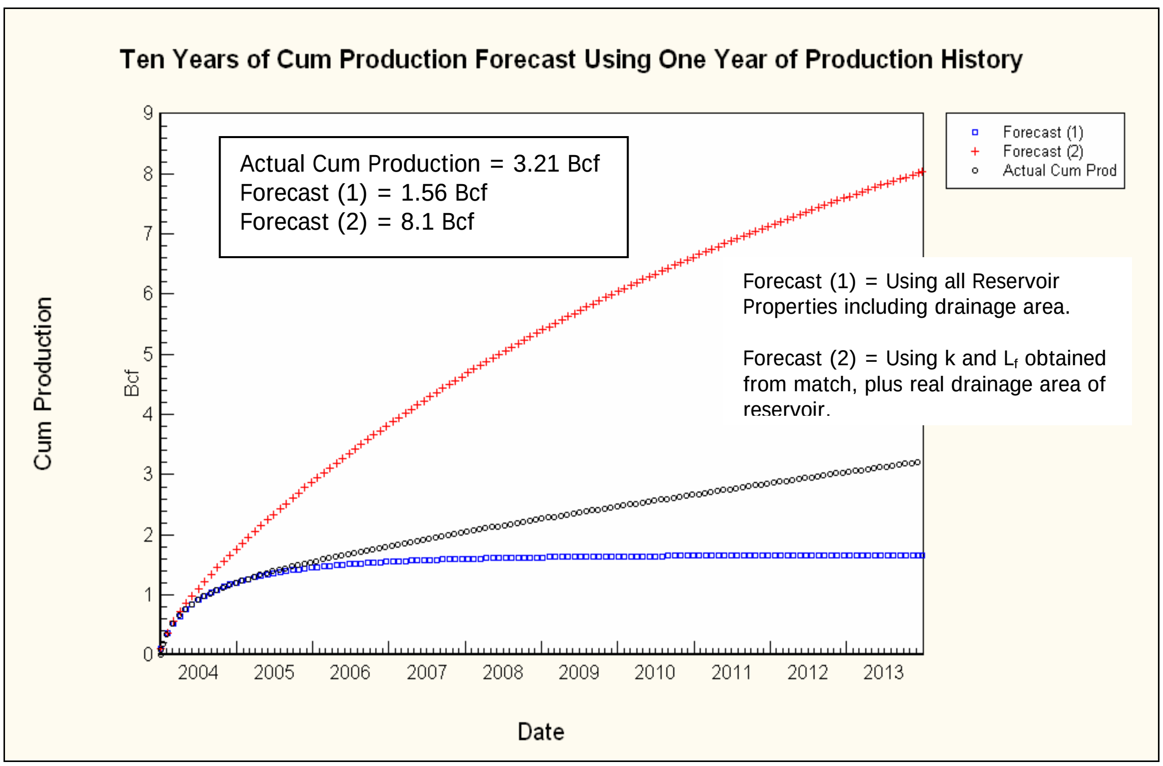

Fig 4.14 *Cumulative Gas Forecast for Case No 15*

Fig. 4.14 illustrates the 10-year gas production forecasts for case No15. Since the drainage area for this case was underestimated by a factor of almost 9 from the history match analysis (18 acres vs. 160 acres), Forecast (1) was also underestimated with an error of -51%. Forecast (2) clearly shows that cum gas production for 10 years will be overestimated if the permeability and fracture half-length calculated from the history match are used with the real drainage area of the well to forecast cumulative production. The overestimation of 10 years gas production for Forecast (2) has an error of +152 %.

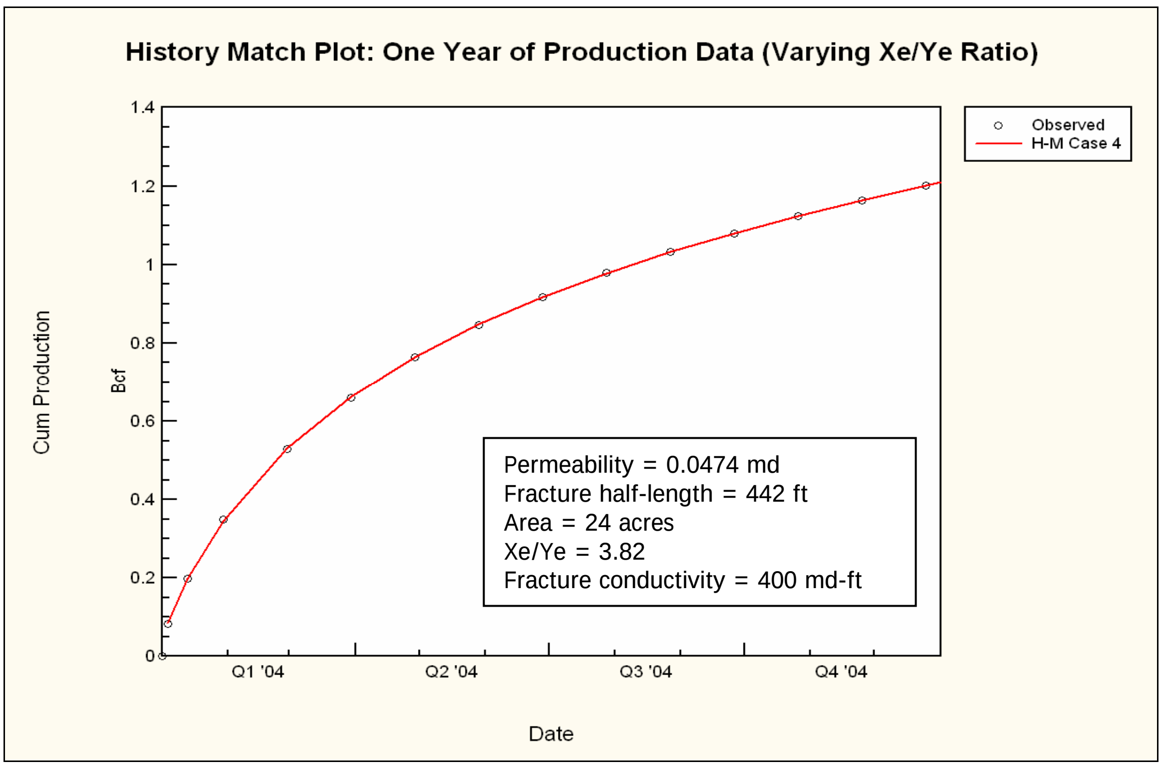

Fig 4.15 *History Match Plot of the Cum Production for Reservoir Model case No 15, Varying the Aspect Ratio*

A better match for simulation case No15 could be obtained by changing the geometry of the drainage area of the well as shown in Fig. 4.15. Reservoir engineers often try to match the production data better by varying the aspect ratio (rectangular vs. square) and claiming that there is a geologic reason to use a rectangularly shaped drainage area. Although this match is a valid match of the data, it does not fit the characteristics and properties of the reservoir used in the simulation.

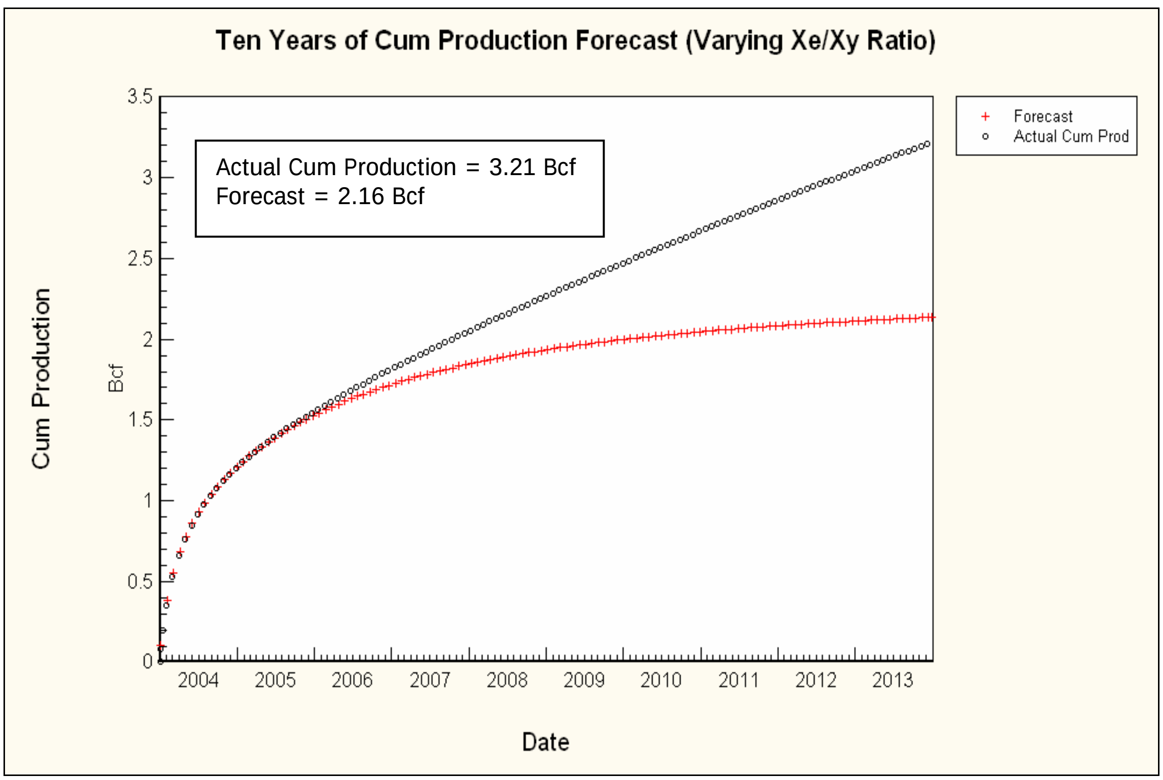

***Fig 4.16** Cumulative Gas Forecast for Case No 15, Varying the Aspect Ratio*

Even when the aspect ratio was varied to match the production data in case No 15, the cumulative production forecast for 10 years was underestimated with an error of

33%, as shown in Fig. 4.16. The main factor for this forecast to be underestimated is the small drainage area predicted by the history match.

4.2.3 Production History = 1 month

Table 4.7 *Reservoir Data for Simulation Case No 16*

Case N_o	16
$k_{(Top\ Layer)}$, md	0.1
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	1.45
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

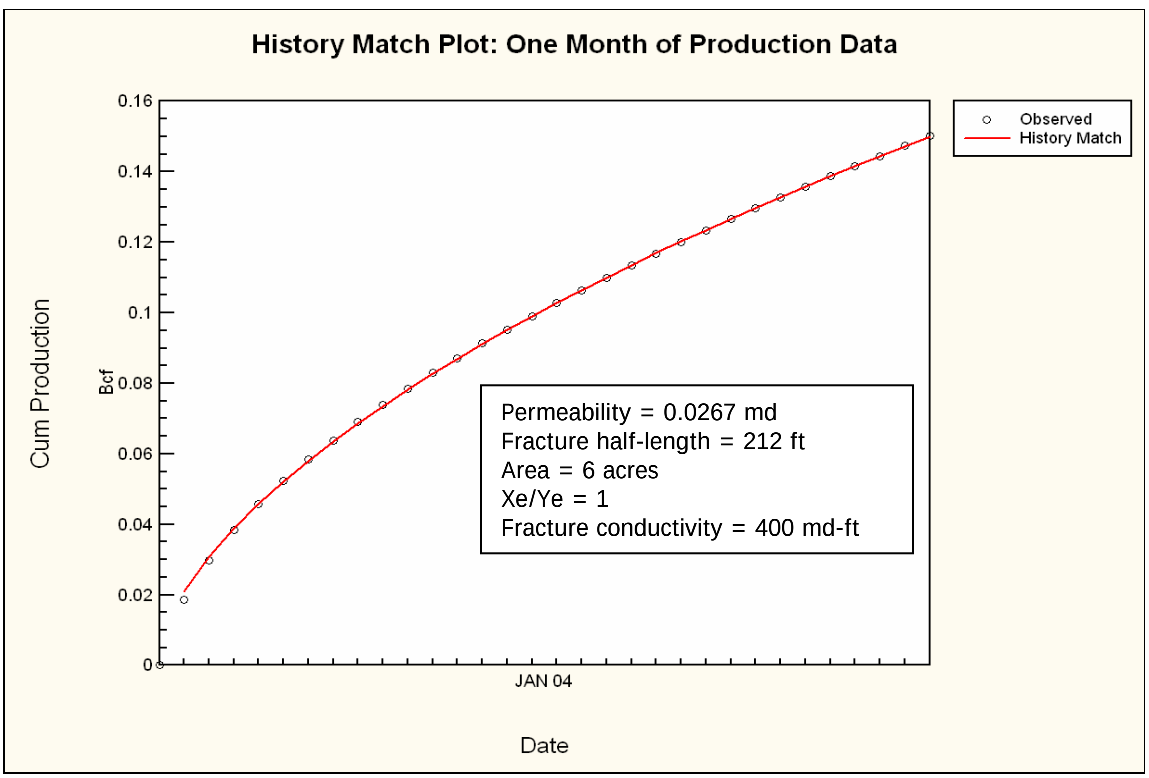

Fig 4.17 *History Match Plot of the Cum Production for Reservoir Model Case No 16*

Simulation case No 16 is the same simulation model as simulation case No 10 and 13, as shown in Table 4.7; however, it was analyzed with only one month of production data to see the variability of properties results when few production data are history matched in tight gas reservoirs. As one can see in Fig 4.17, the production data matched perfectly, however, the results do not fit the parameters input in the simulation model. The permeability-thickness product estimated from the history match (*kh= 2.67 md-ft*) is overestimated with an error of +84 %. The fracture half-length estimated is 40% in error. With only one month of data to analyze, the effective drainage area of the well was very small, resulting in an underestimation of 96% (6 acres vs. 160 acres).

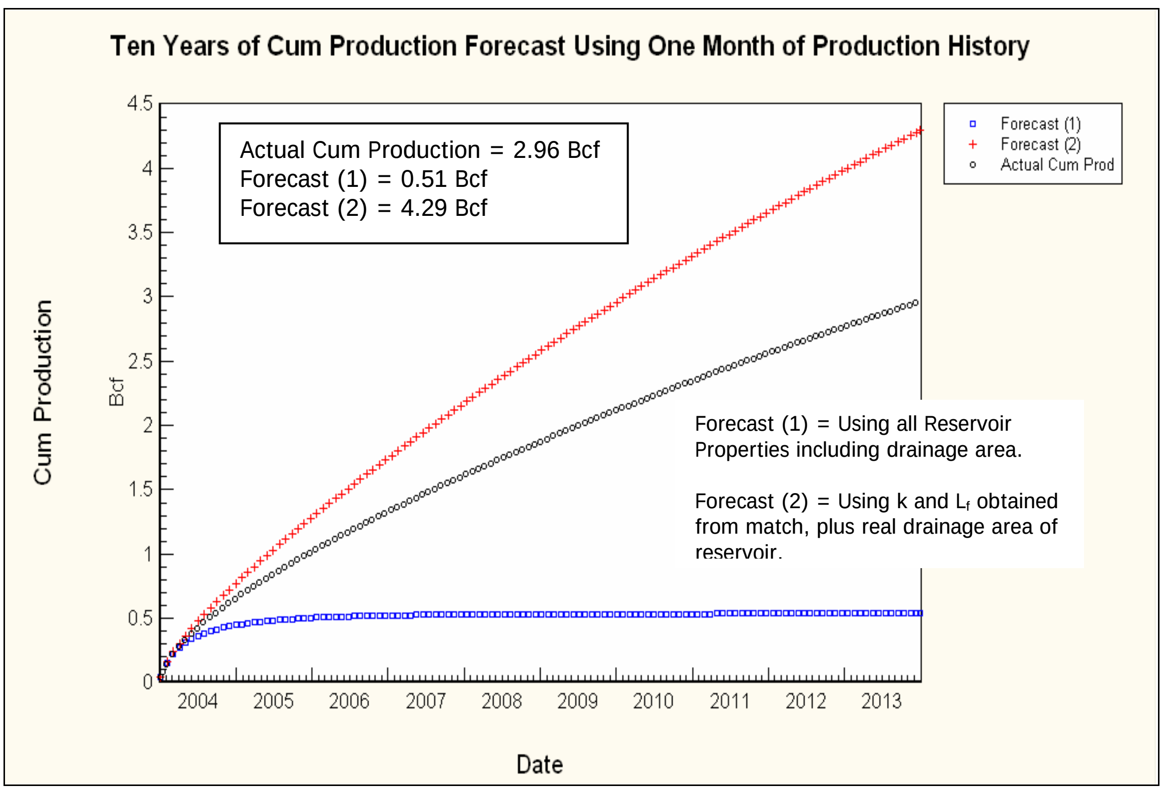

Fig 4.18 *Cumulative Gas Forecast for Case No 16*

In Fig. 4.18 we can see that Forecast (1) is underestimated by 82% due to the small drainage area predicted by the history match. Forecast (2), on the other hand, was overestimated by 45% due to the large value of permeability estimated by the match.

Table 4.8 *Reservoir Data for Simulation Case No 17*

Case N_o	17
$k_{(Top\ Layer)}$, md	1.0
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	5.95
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

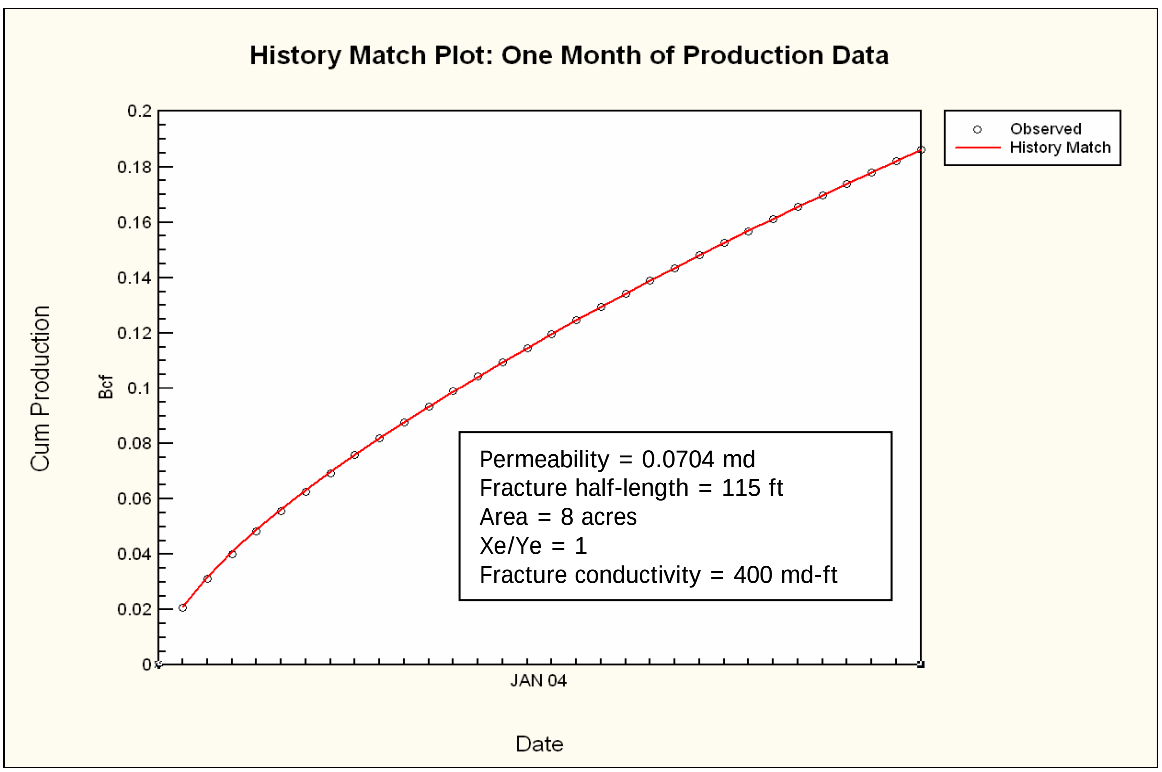

Fig 4.19 *History Match Plot of the Cum Production for Reservoir Model Case No 17*

Case No 17 is the same as case No 11, as shown in Table 4.8, except we only analyzed the first month of production. In simulation case No 17, the gas production during the first month is controlled mainly by the top interval which has a permeability of 1.0 md making the history match estimate a higher permeability value for the whole reservoir system. Fig 4.19 displays a perfect history match for simulation case No 17; however, the results of reservoir properties are incorrect. The permeability-thickness product was overestimated by 19% error. The fracture half-length and the drainage area were underestimated by -67 % and -95%, respectively.

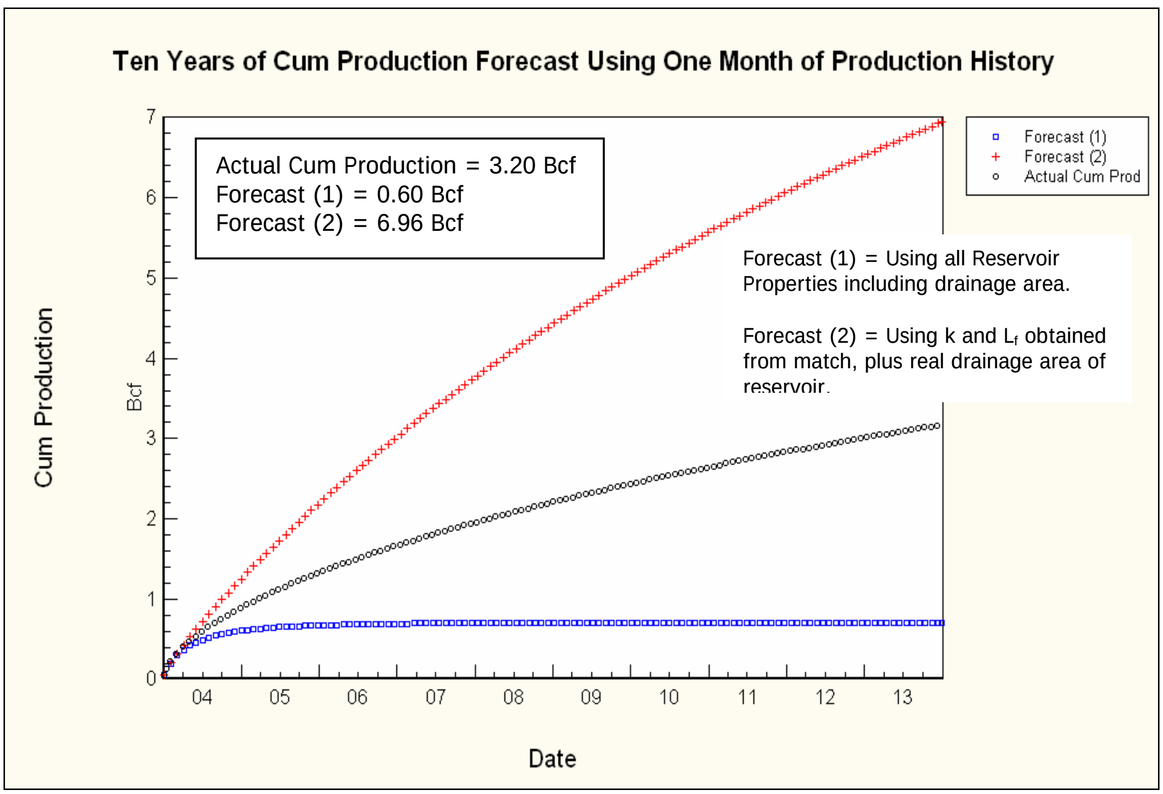

Fig. 4.20 *Cumulative Gas Forecast for Case No 17*

Fig. 4.20 portrays the forecasts for simulation case No 17. Once again, Forecast (1) was underestimated by -81% because of the small drainage area of the well estimated by the history match; on the other hand, Forecast (2) was overestimated by 117% because of the large value of permeability estimated.

Table 4.9 *Reservoir Data for Simulation Case No 18*

Case N_o	18
$k_{(Top\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	50.95
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

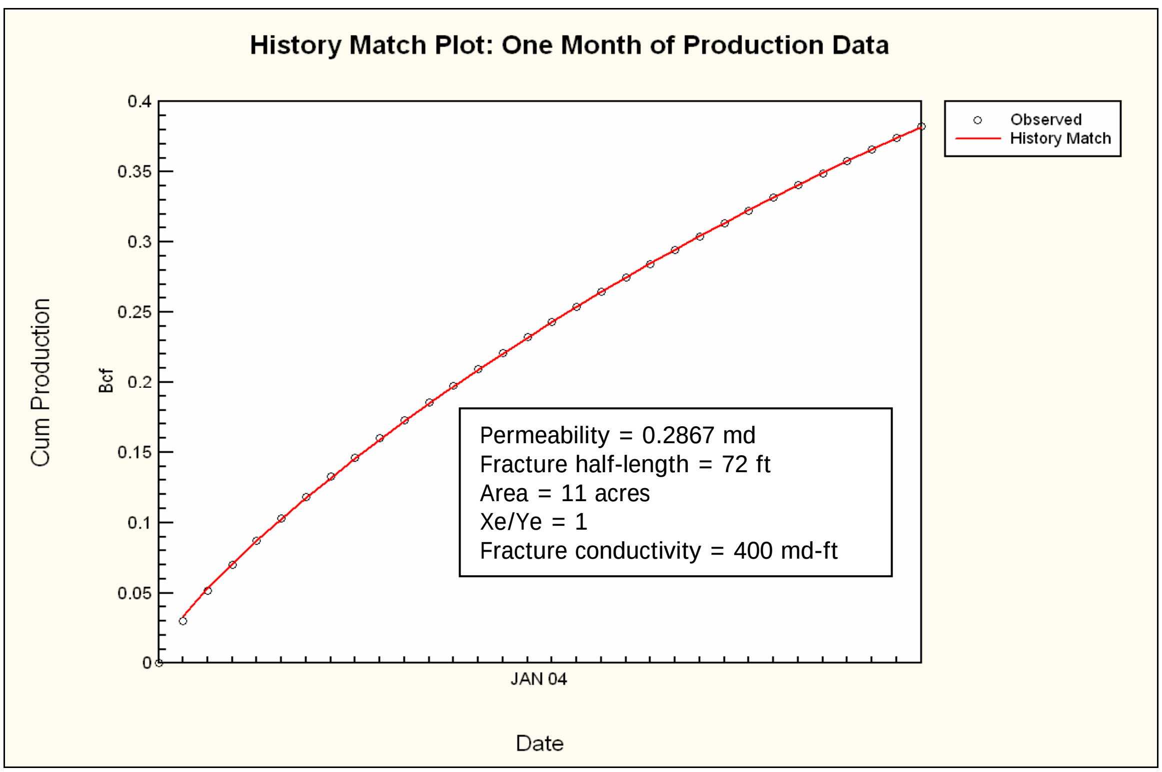

Fig 4.21 *History Match Plot of the Cum Production for Reservoir Model Case No 18*

Unlike simulation case No 12 and No 15 where the drainage area geometry had to be varied in order obtain a good match**,** simulation case No 18 which also presents a high permeability contrast, as shown in Table 4.9 obtained a perfect match without varying the reservoir geometry parameter as shown in Fig. 4.21. However, the reservoir properties estimated by the match do not correspond to the reservoir properties input in the simulation model.

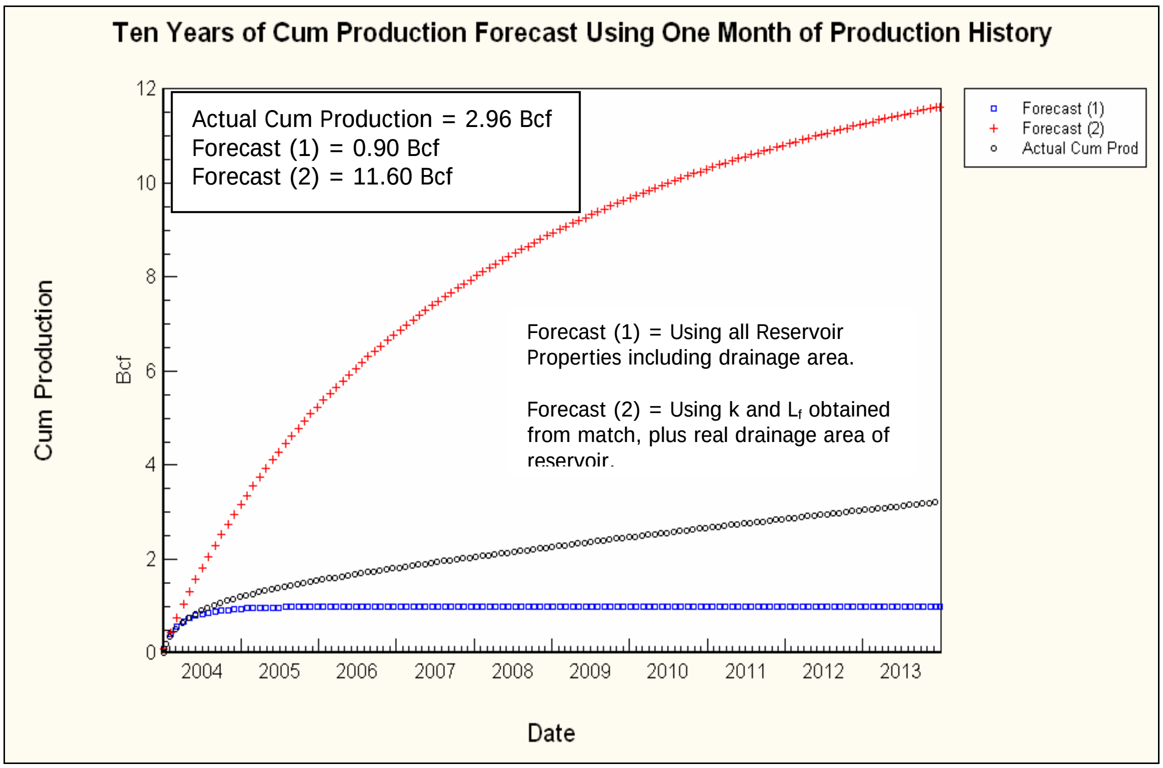

Fig 4.22 *Cumulative Gas Forecast for Case No 18*

Fig. 4.22 displays the reserves forecasts from simulation case No 18. Forecast (1) was underestimated with an error of –72 % while Forecast (2) was overestimated with an error of 261%. Although the permeability-thickness product was underestimated in this case by almost one half of permeability-thickness used in the simulation, the single-layer description makes the permeability be distributed evenly throughout the entire net pay making the low permeability layer, which contains the majority of gas in place, have a higher permeability value, sometimes in the order of one or two magnitudes, thus, overestimating the production forecast.

A summary of the results from case No 10-18 can be found on the Table on p.119, and the significance of the results are discussed in CHAPTER V of this thesis.

4.3 Scenario Two: Simulation Results

4.3.1 Production History = 36 months

Case No 91 is for Scenario two which is a two-layer reservoir where the high permeability layer has a limited drainage area compared to the low permeability layer, as shown in Table 4.10. Again, the low short term production rates are dominated by the high permeability layer which most of the gas in place is in the low permeability layer.

Table 4.10 *Reservoir Data for Simulation Case No 91*

Case N_o	91
$k_{(Top\ Layer)}$, md	0.1
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	1.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

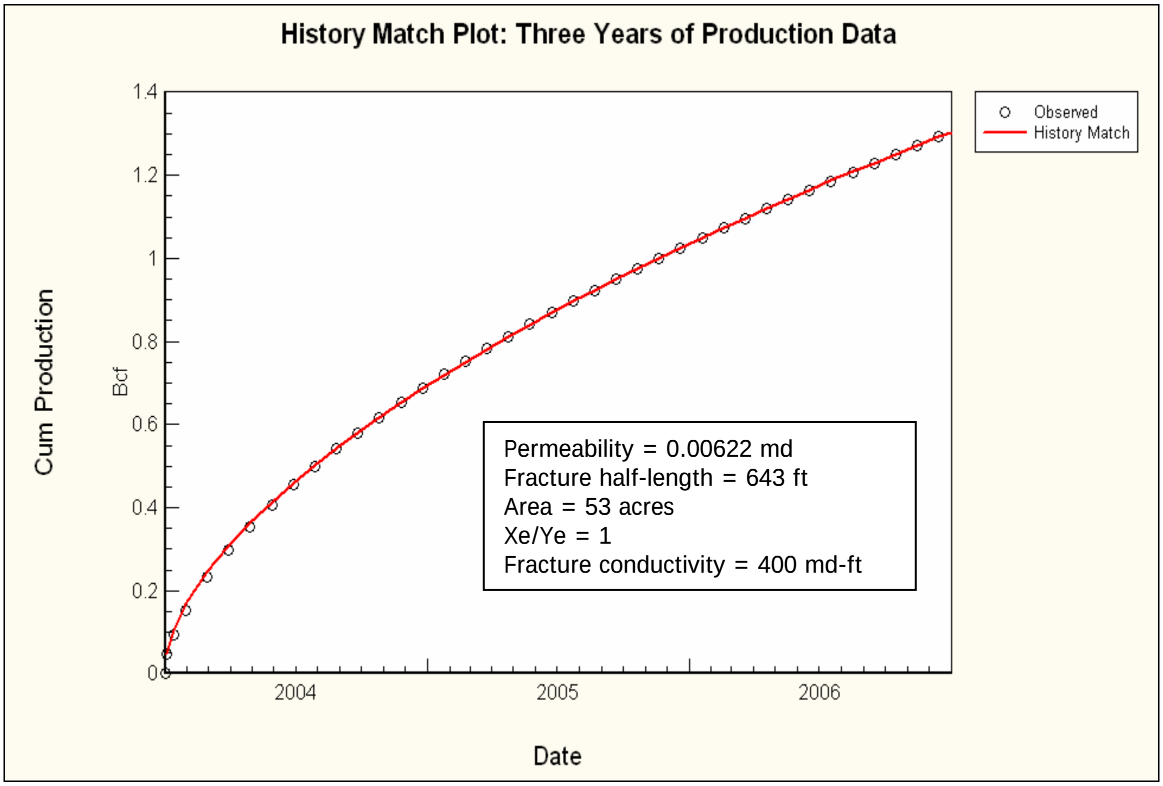

Fig. 4.23 *History Match Plot of the Cum Production for Reservoir Model Case No 91*

Fig 4.23 displays a perfect history match for the data from case No 91 from Table A-2. The properties obtained by the match, however, do not correspond to the reservoir properties used in the simulation model. The permeability-thickness product and the well drainage area were underestimated by -67% and -66%, respectively. The fracture half-length was overestimated by 84%. In this case, one can see that the equivalent single-layer permeability obtained from the history match is even smaller than the permeability of the low permeability layer. This phenomenon is due to the fact that in three years the high permeability layer which has a limited areal extent has depleted completely; therefore, the permeability-thickness product calculation starts being controlled principally by the permeability value of the low permeability layer which covers only 90% of the total thickness.

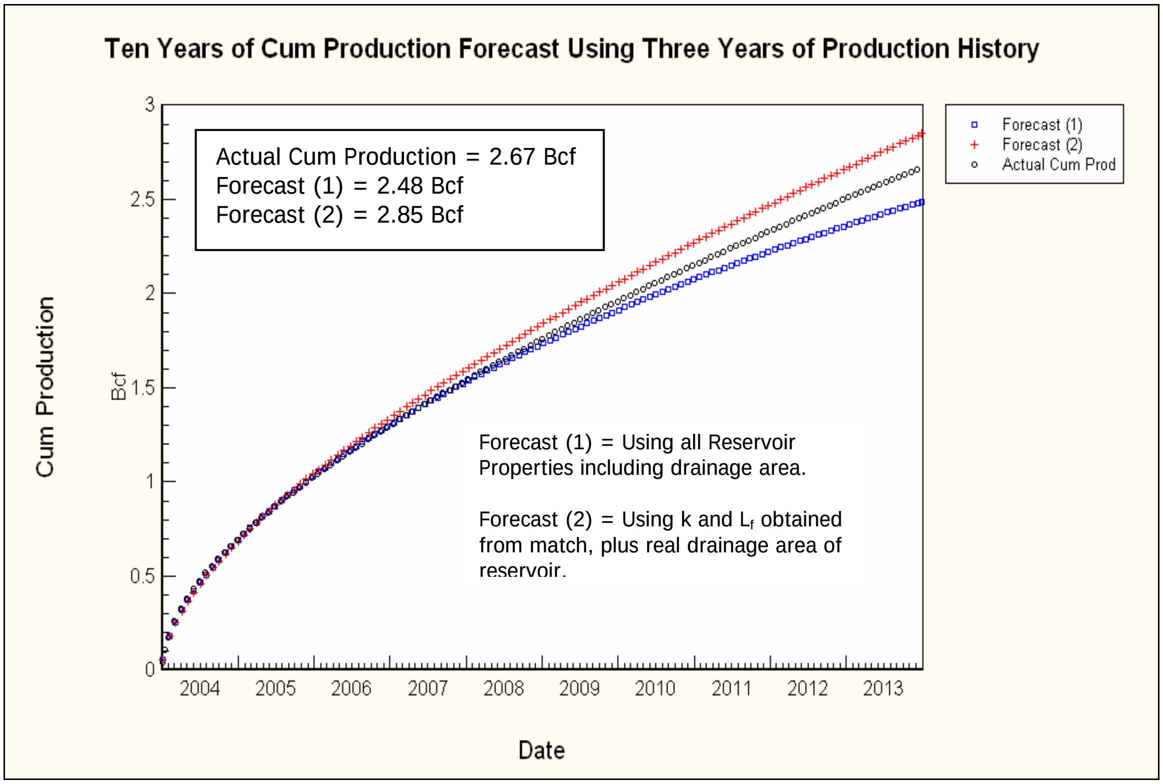

Fig 4.24 *Cumulative Gas Forecast for Case No 91*

Although the values calculated by the history match in case No 91 are incorrect, the 10 year cumulative production forecast using that set of values for reservoir properties gives reliable estimates of reserves falling within the ± 10% error as shown in Fig. 4.24. The reason is that in 10 years, the reservoir has only produced 18% of the total gas in place; in addition, the production data (three years of production history) that were used in the history match analysis to estimate the reservoir properties used to forecast the gas production, accounts for almost 50% of the gas produced in that 10 year period.

Case No 92 is for the two-layer case where the high permeability layer (1.0 md) is of limited extent compared to the low permeability layer (0.01 md), as shown in Table 4.11.

***Table 4.11** Reservoir Data for Simulation Case No 92*

Case N_o	92
$k_{(Top\ Layer)}$, md	1.0
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	10.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

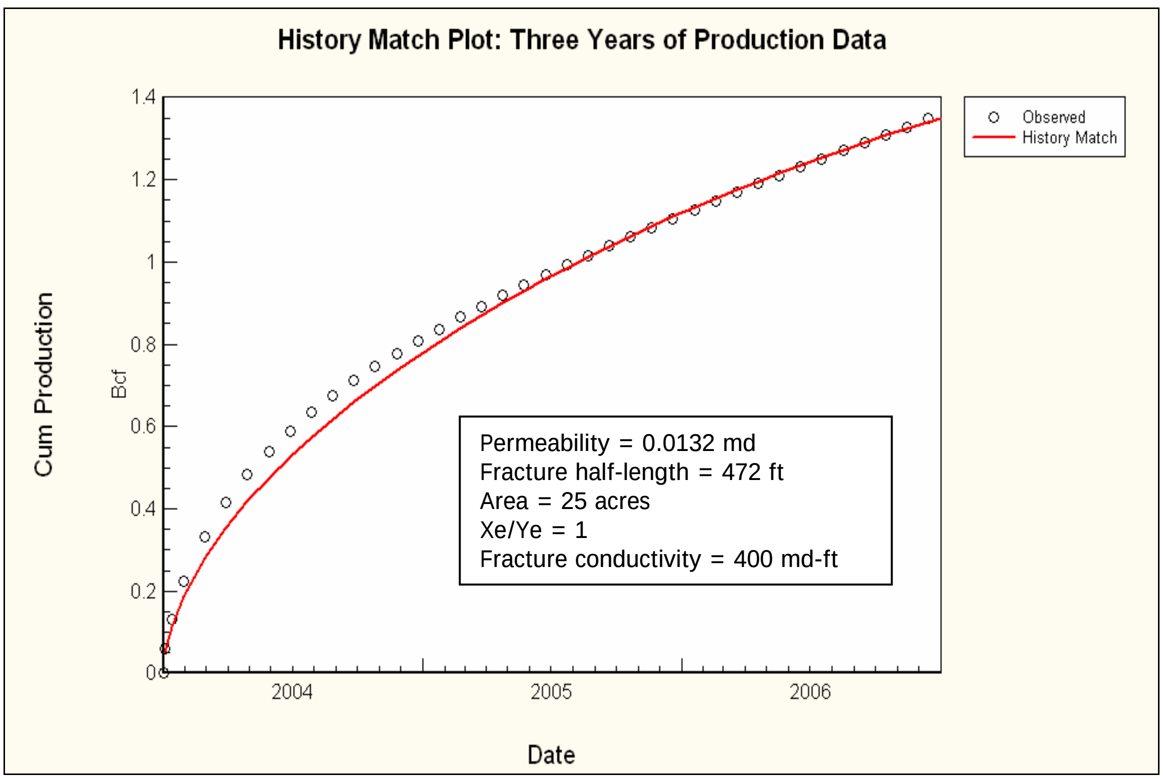

***Fig. 4.25** History Match Plot of the Cum Production for Reservoir Model Case No 92*

Fig. 4.25 shows the history match for run case No 92. The data did not match well in the early time, once again, because of the rapid decline rate of the high permeability layer. However, unlike cases in scenario one where models with medium contrasts in permeability within the layers would still give perfect history matches without changing the geometry of the reservoir, in scenario two, the production data in models with the same specification as mentioned above will not provide perfect matches without changing the geometry of the reservoir.

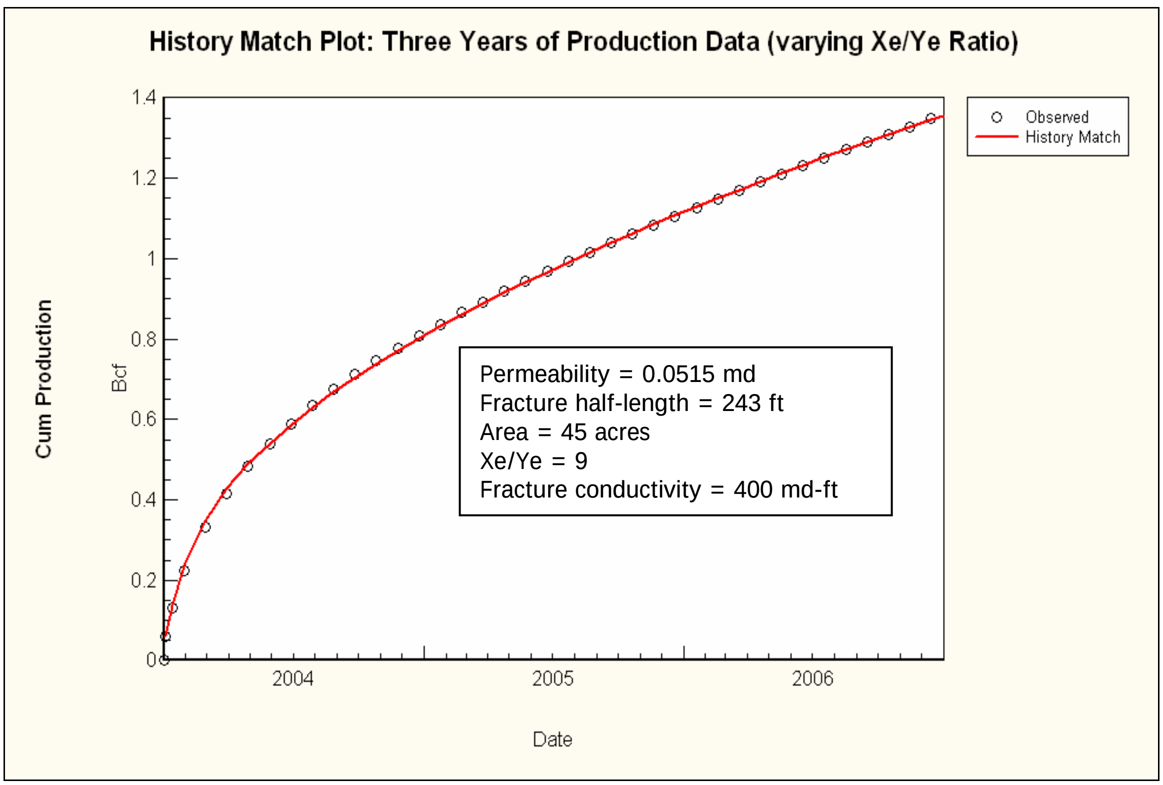

Fig. 4.26 *History Match Plot of the Cum Production for Reservoir Model Case No 92, Varying the Aspect Ratio*

Fig. 4.26 displays a perfect match for run case No 92. This perfect match was obtained by changing the geometry of the reservoir by a factor of 9, making it a rectangle rather than a square. The geometry dictated by the history match however, does not represent the real geometry of the reservoir. The reservoir properties values calculated area also incorrect. Again, this example illustrates the uniqueness problems faced by petroleum engineers trying to history match complex, layered tight gas reservoirs using simple models.

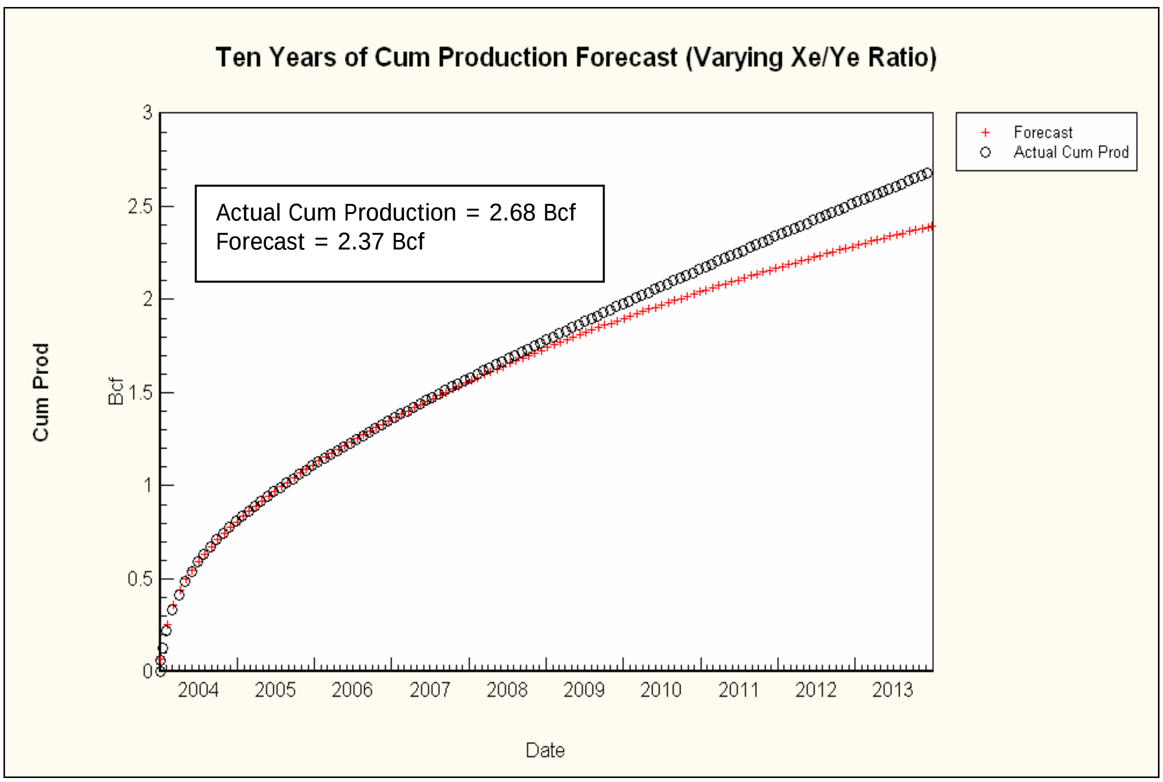

Fig 4.27 *Cumulative Gas Forecast for Case No 92, Varying the Aspect Ratio*

Fig. 4.27 is the 10-year production forecast for Case No 92 after obtaining a perfect match by varying the aspect ratio (Xe/Ye) of the drainage area. Although neither the reservoir geometry nor the reservoir properties describe the reservoir accurately, the 10 year cumulative forecast calculated using the match gives a fair estimate of reserves with an error of 11%. If one notices in the history match results, the variation in the aspect ratio gave a larger drainage area for the well giving more gas in place to be produced. Moreover, the data used in the history match accounts for 51% of the 10 year production forecast, therefore, making only 49% of the 10 year cum production to be forecasted. If a longer time production were to be estimated, the forecast would no longer be suitable because of the erroneous reservoir description as well as the reservoir properties.

Case No 93 is for the two-layer case where the high permeability layer is 10.0 md and is of limited extent compared to the low permeability layer (0.01 md), as shown in Table 4.12.

Table 4.12 *Reservoir Data for Simulation Case No 93*

Case N_o	93
$k_{(Top\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	100.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

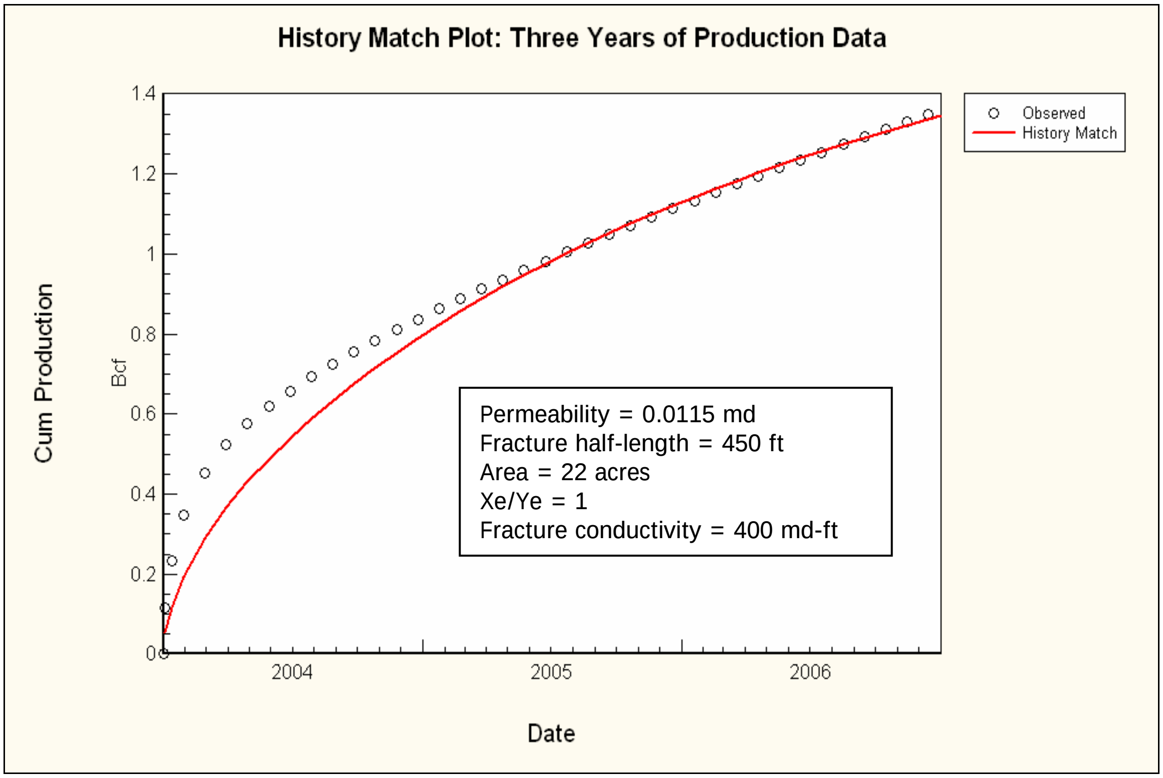

Fig. 4.28 *History Match Plot of the Cum Production for Reservoir Model Case No 93*

In Fig. 4.28 one can observe that the early time production does not match properly using the single layer model because during the first year most of the gas is coming from the high permeability layer. The data starts to match the single layer model better once the high permeability interval has been mostly depleted, and the gas production is being dominated by the low permeability interval.

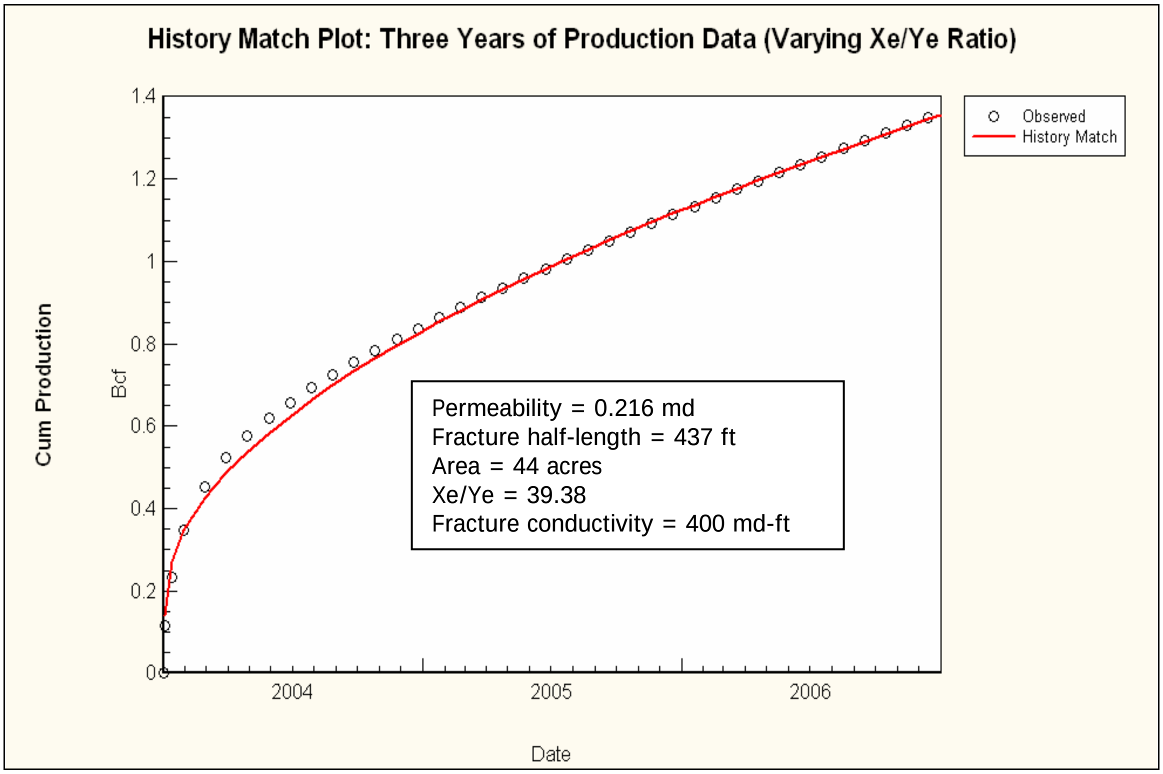

Fig. 4.29 *History Match Plot of the Cum Production for Reservoir Model Case No 93, Varying the Aspect Ratio*

Case No 93 did not match well in the early time even when the geometry of the reservoir was varied as shown in Fig 4.29. However, it is a better match than the one shown in Fig. 4.28. If you notice, however, when the data were matched in the early time, the permeability and the drainage area values calculated were increased substantially.

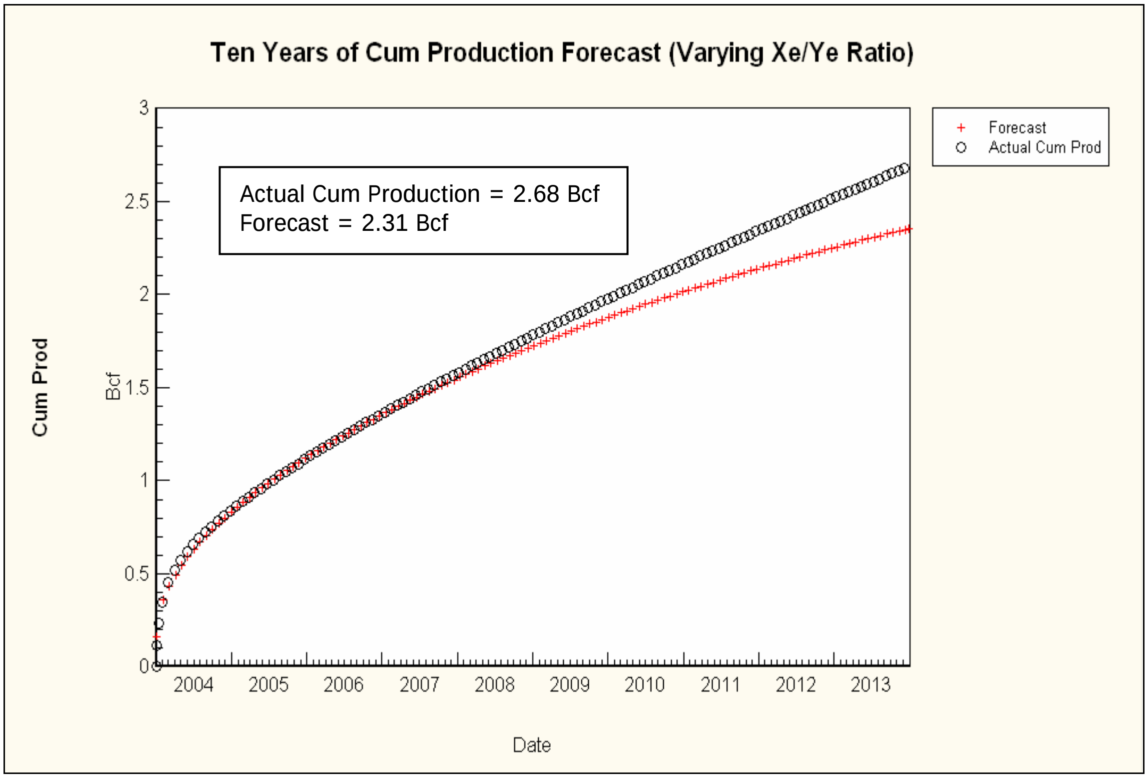

Fig 4.30 *Cumulative Gas Forecast for Case No 93, Varying the Aspect Ratio*

Fig. 4.30 shows the 10 year production forecast for case No 93 when the rectangular drainage area results (Fig. 4.29) were used to compute the well performance. This forecast has an error of only15%; however, the reservoir properties and the reservoir geometry used for the reserves forecast do not describe the reservoir correctly.

4.3.2 Production History = 12 months

Case No 94 is same as case No 91, as shown in Table 4.13, except only the first twelve months of production data were analyzed.

Table 4.13 *Reservoir Data for Simulation Case No 94*

Case N_o	94
$k_{(Top\ Layer)}$, md	0.1
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	1.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

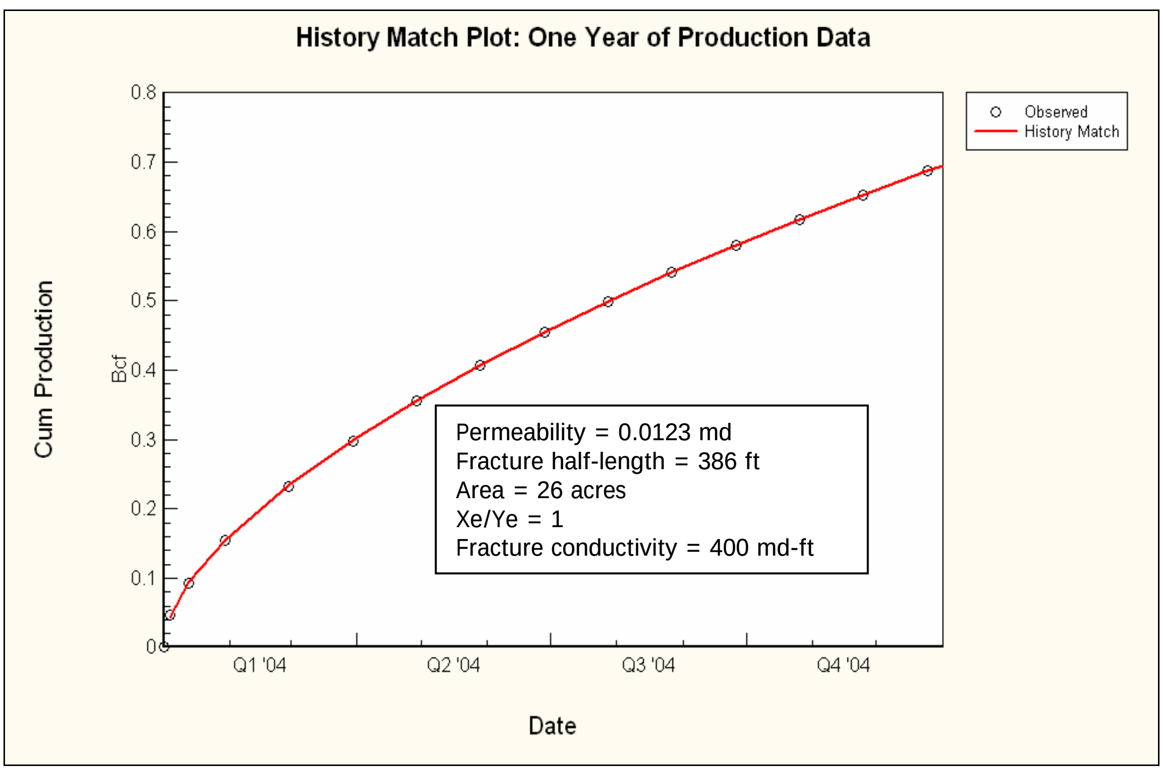

Fig. 4.31 *History Match Plot of the Cum Production for Reservoir Model Case No 94*

Fig. 4.31 shows an excellent match for case No 94. The permeability-thickness and the drainage area of the well were underestimated by 35% and 84%, respectively. However, the calculated fracture half-length calculated has a 10% error with respect to the fracture-half length used in the simulation. Unlike in case No 91 where the permeability-thickness product calculation was dominated only by the low permeability layer because high permeability had depleted completely, in case No 94 the permeability-thickness product calculation is still dominated by both layers given that in one year the high permeability layer has only depleted partially; Hence, making the equivalent single-layer permeability estimated by the history match at least be greater than the permeability in the low permeability layer.

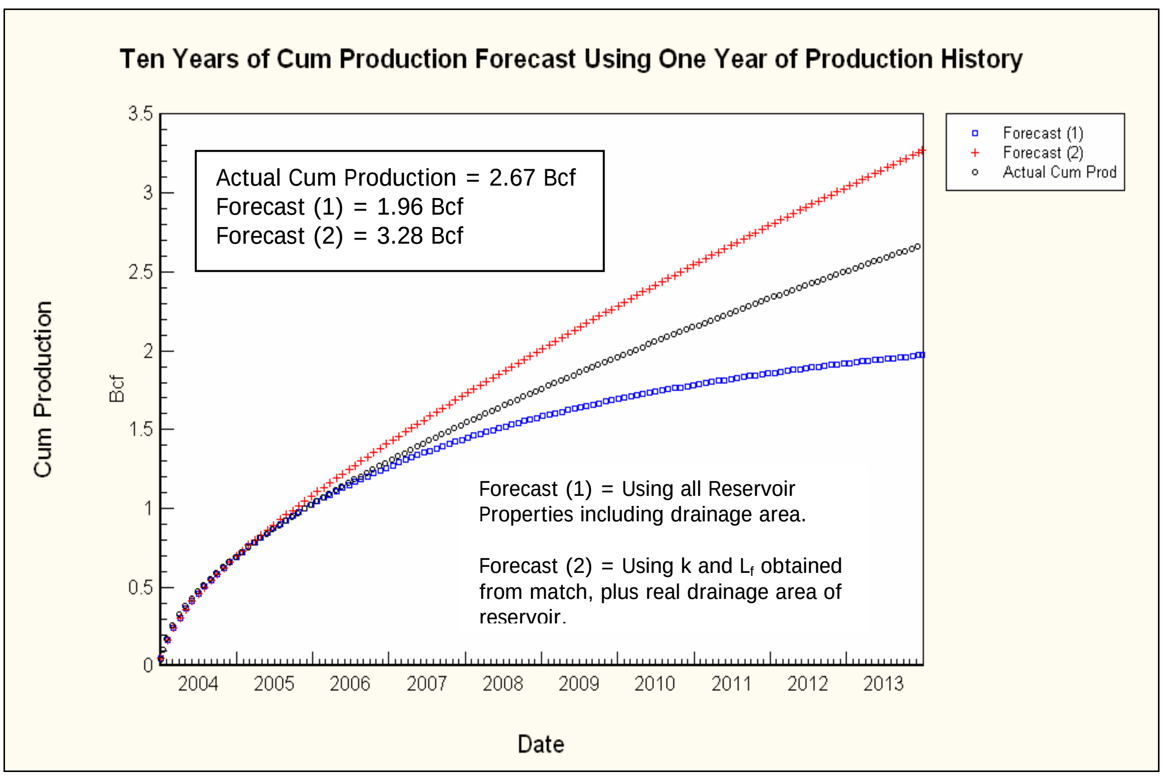

Fig 4.32 *Cumulative Gas Forecast for Case No 94*

Fig. 4.32 shows the ten-year gas production forecast for case No 94. Neither Forecast (1) nor (2) presented a reliable 10 year cumulative gas production forecast. Forecast (1) had an error of -27% because the drainage area is too small while Forecast (2) had an error of 23% because the permeability was too large.

Case No 95 is same as case No 92, as shown in Table 4.14, except only the first twelve months of production data were analyzed.

Table 4.14 *Reservoir Data for Simulation Case No 95*

Case N_o	95
$k_{(Top\ Layer)}$, md	1.0
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	10.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

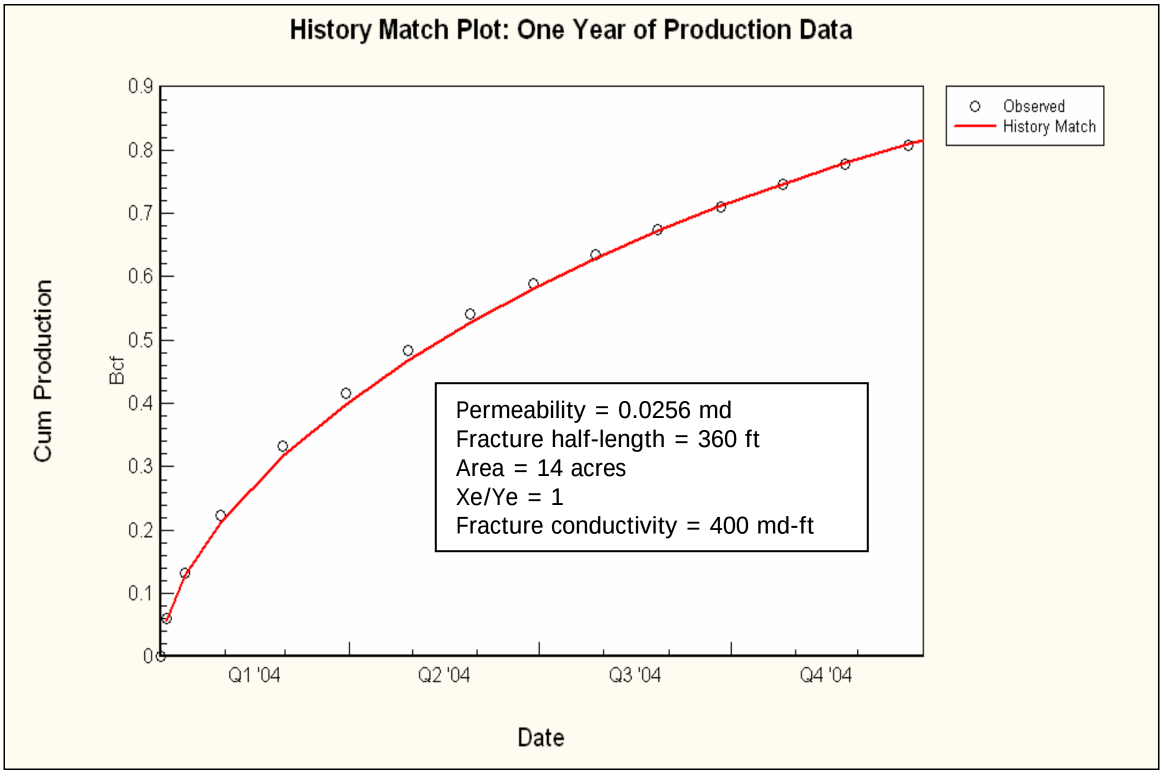

Fig. 4.33 *History Match Plot of the Cum Production for Reservoir Model Case No 95*

Fig. 4.33 shows the history match for run case No 95. The permeability-thickness and the drainage area were underestimated by -77% and -91.25%, respectively. The fracture half-length estimate was within 3% of the input value.

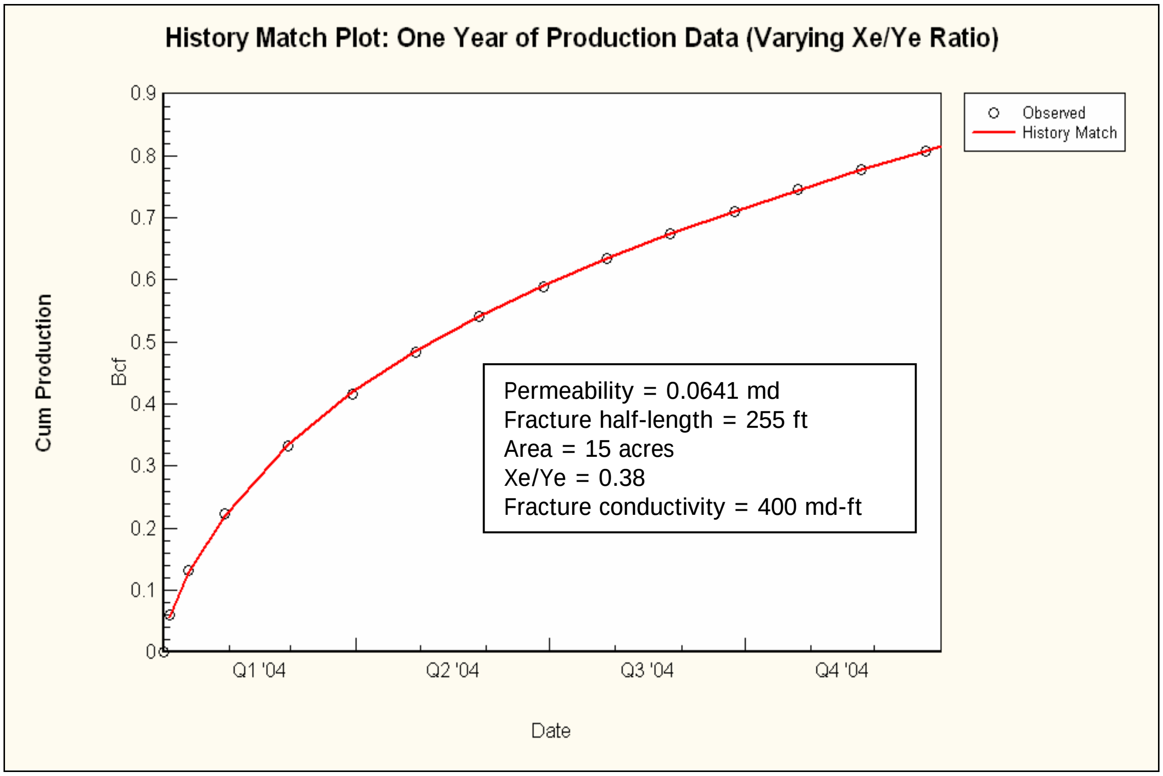

Fig. 4.34 *History Match Plot of the Cum Production for Reservoir Model Case No 95, Varying the Aspect Ratio*

After matching the data perfectly for case No 95 by varying the aspect ratio, one can observe in Fig. 4.34 that the permeability estimated was increased by approximately 150% from the previous history match for the same case as shown in Fig. 4.33. The fracture half-length was underestimated by -28%, and the drainage area did not vary much from the one calculated from the match in Fig. 4.33.

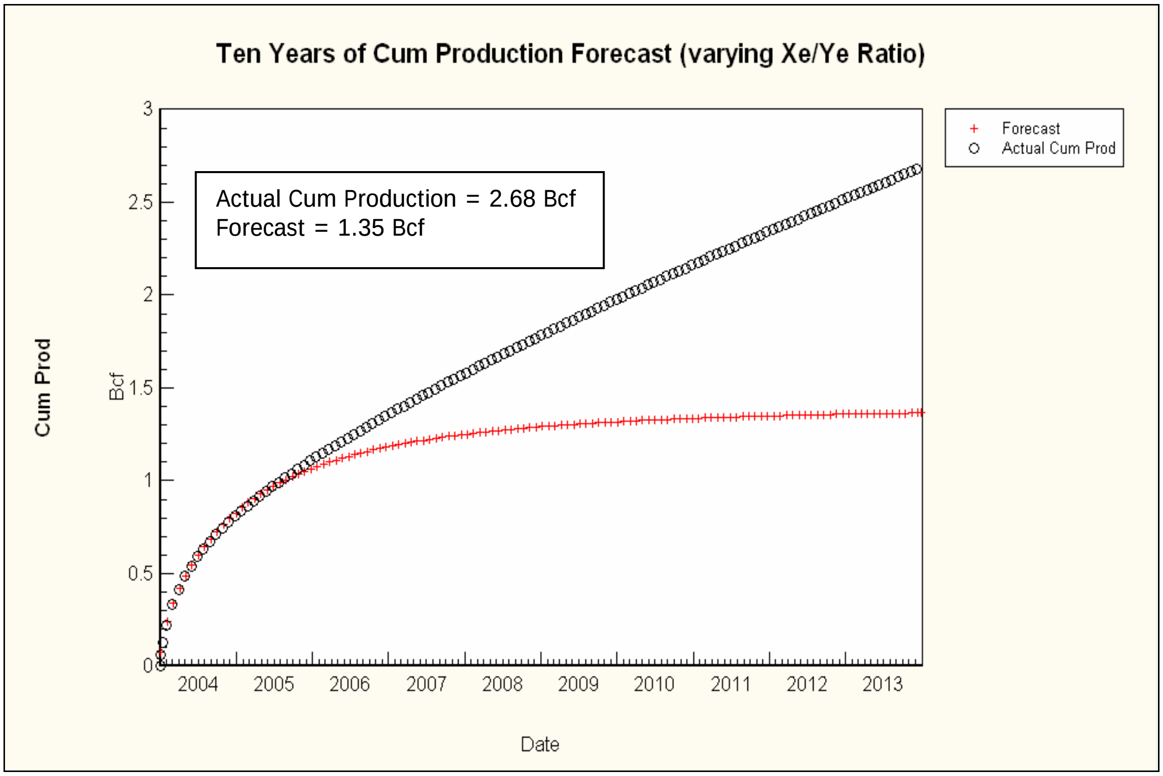

Fig 4.35 *Cumulative Gas Forecast for Case No 95, Varying the Aspect Ratio*

Even when the aspect ratio was varied to match the production data in case No 95, the cumulative production forecast for 10 years was underestimated by 50% as shown in Fig. 4.35. The main factor of this forecast underestimation is the small drainage area estimated by the history match.

Case No 96 is identical as case No 93, as shown in Table 4.15, except only the first twelve months of production data were analyzed.

Table 4.15 *Reservoir Data for Simulation Case No 96*

Case N_o	96
$k_{(Top\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	100.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

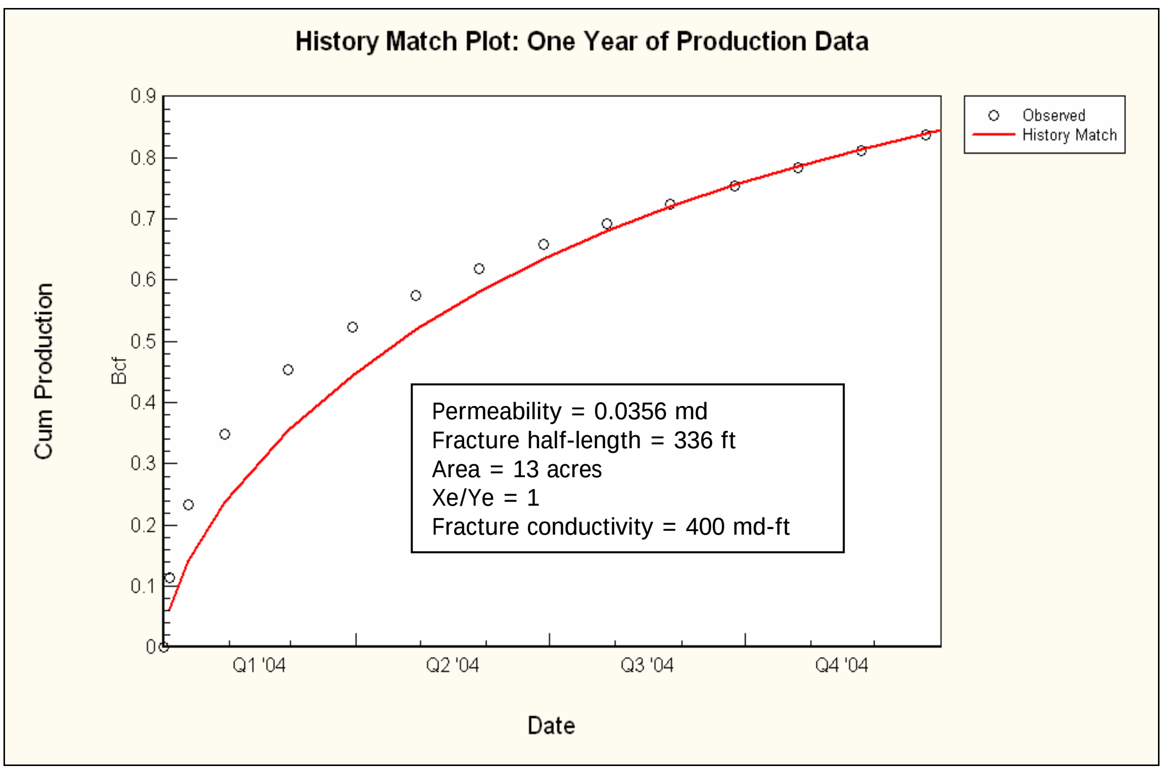

Fig. 4.36 *History Match Plot of the Cum Production for Reservoir Model Case No 96*

Fig. 4.36 exhibits the production history match for case No 96 from Table A.2. The plot shows an unacceptable match for one year of production history. The gas production in the first one half of the year does not match well due to the high gas production contribution of the high permeability layer to the overall production. The production data start to match properly at a later time when the high permeability layer is essentially depleted, and the gas production starts to be controlled by the low permeability interval. The permeability-thickness product calculated by the history match (*kh= 3.56 md-ft*) was underestimated and presented an error of -94.47 % with respect to the permeability thickness product (*kh= 100.9 md-ft*) used in the simulation model. The history match shows a fracture half-length (L_f) of 336 ft, which has a – 4.0% error from the true fracture half-length of the simulation model. The area calculated by the history match was underestimated with an error of -92% (13 acres vs. 160 acres).

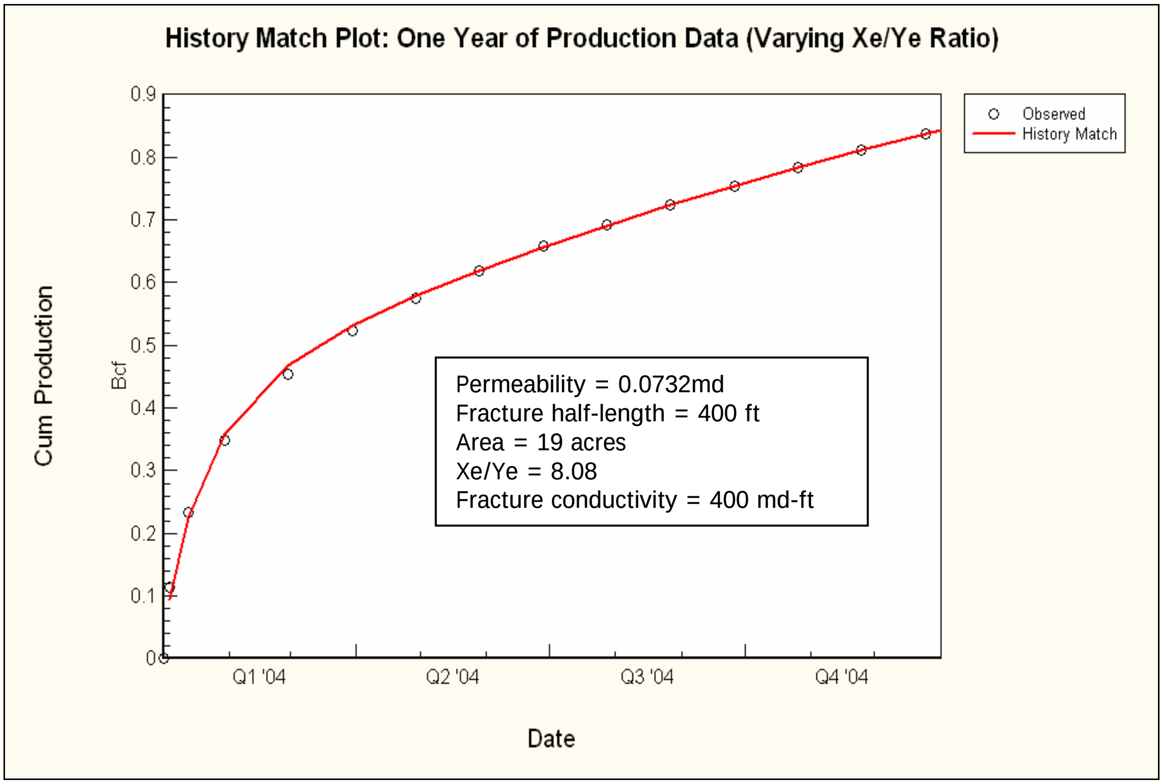

Fig. 4.37 *History Match Plot of the Cum Production for Reservoir Model Case No 96, Varying the Aspect Ratio*

Even when an excellent match was obtained by varying a rectangular drainage area as shown in Fig. 4.37, the resulting match gave erroneous results for properties of the reservoir. Once again, we see that we can use a rectangular, single-layer model to obtain an excellent match from a 2-layer, square reservoir. This non-uniqueness feature can cause real problems when one tries to analyze real reservoir if one does not understand the issues.

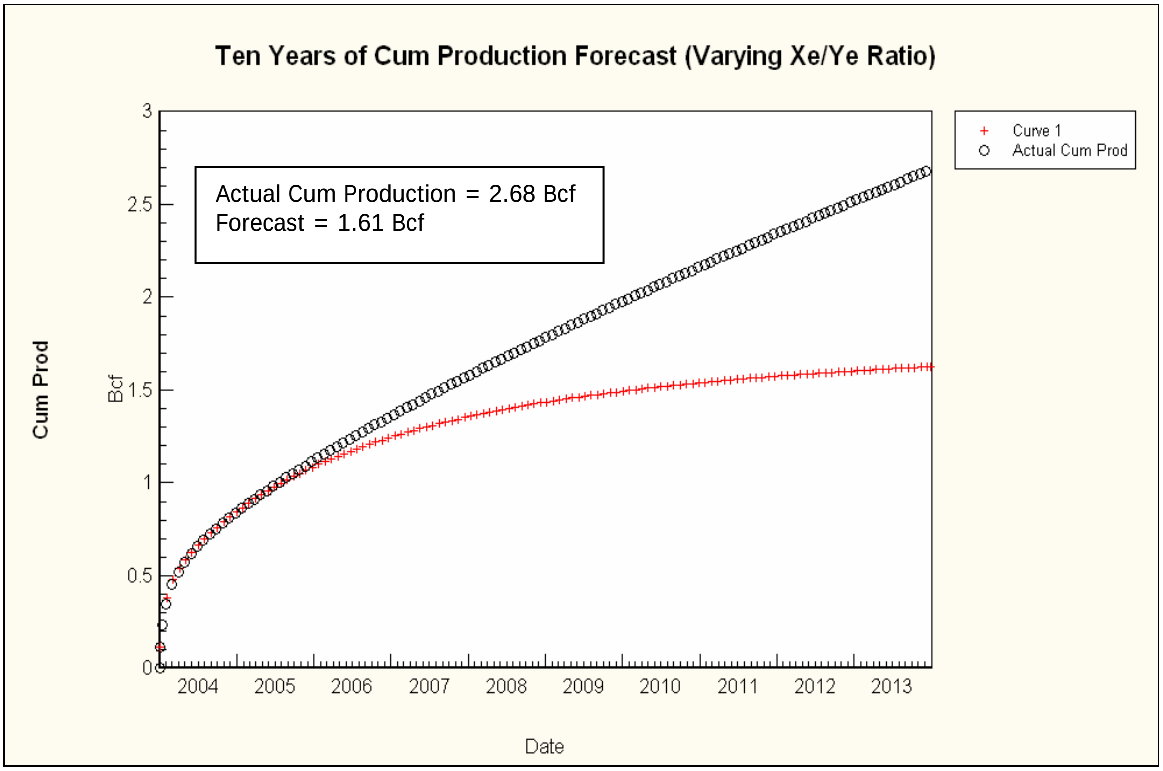

Fig 4.38 *Cumulative Gas Forecast for Case No 96, Varying the Aspect Ratio*

Using the values obtained in Fig. 4.37, we can forecast ten-year gas production. In Fig. 4.38, we see that this "bogus" method does not result in an accurate forecast of production. The ten-year gas production for case No 96 was underestimated by 40%.

4.3.3 Production History= 1 month

Case No 97 is identical to case No 91 and No 94, as shown in Table 4.16, except now we are only analyzing one month of production data versus three years and one year in case No 91 and No 94 respectively.

Table 4.16 *Reservoir Data for Simulation Case No 97*

Case N_o	97
$k_{(Top\ Layer)}$, md	0.1
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	1.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

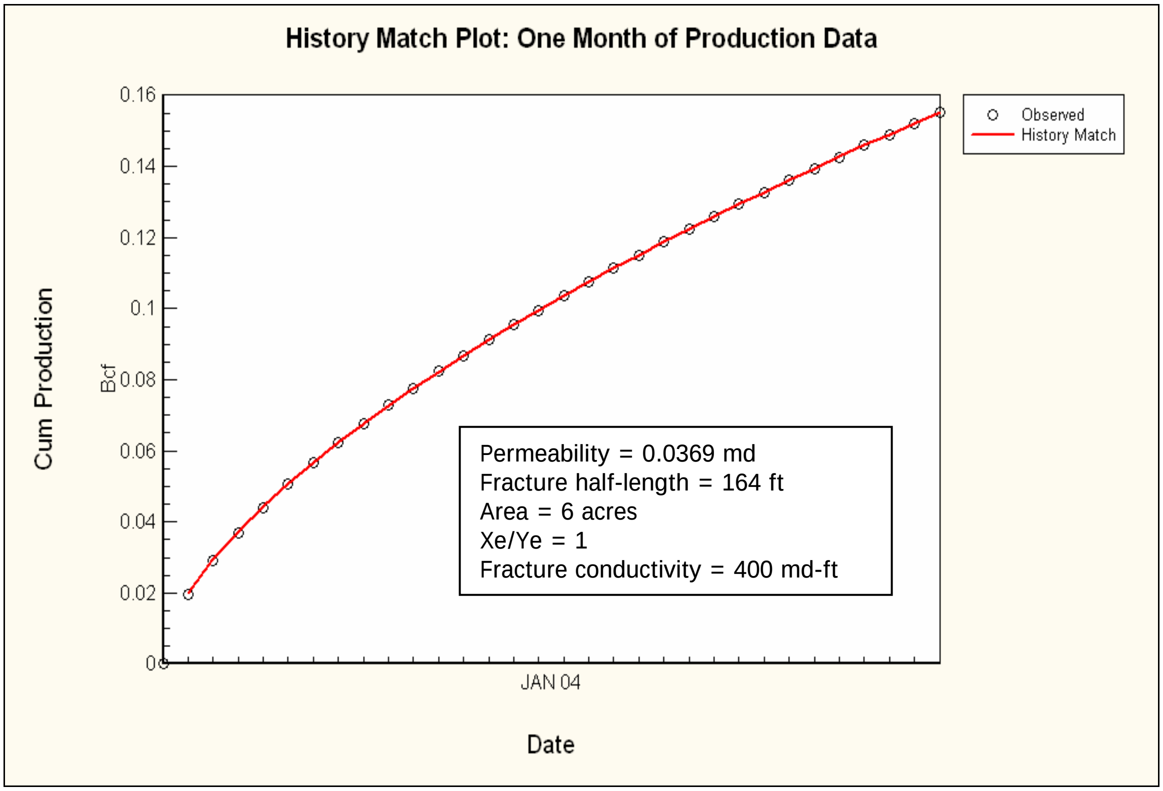

Fig. 4.39 *History Match Plot of the Cum Production for Reservoir Model Case No 97*

Fig 4.39 shows the history match for case No 97 from Table A-2. The production data match perfectly; however, the results do not resemble the parameters input in the simulation model. The permeability-thickness product calculated from the history match (*kh= 3.694 md-ft*) was overestimated by + 94.42%. The fracture half-length was underestimated by -53%. Since the pressure transient will only reach a small radius of investigation with one month of production data, the drainage area for this case was underestimated by 96% (6 acres vs. 160 acres).

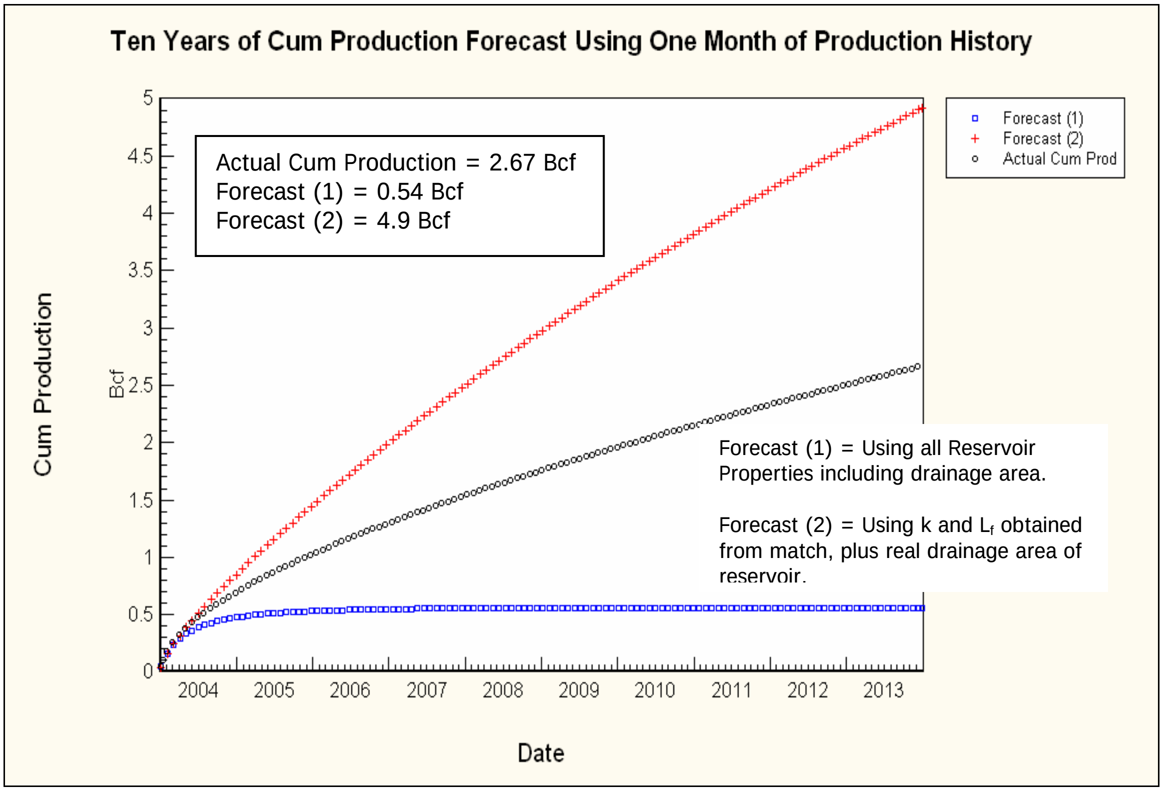

Fig 4.40 *Cumulative Gas Forecast for Case No 97*

Fig. 4.40 displays the ten-year gas production forecast from simulation case No 97. Forecast (1) was underestimated by 80 % because the drainage area is too small while Forecast (2) was overestimated by 84% because the equivalent single-layer model permeability was too large.

Case No 98 is the same to case No 92 and No 95, as shown in Table 4.17, except now we are only analyzing one month of production data

Table 4.17 *Reservoir Data for Simulation Case No 98*

Case N_o	98
$k_{(Top\ Layer)}$, md	1.0
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	10.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

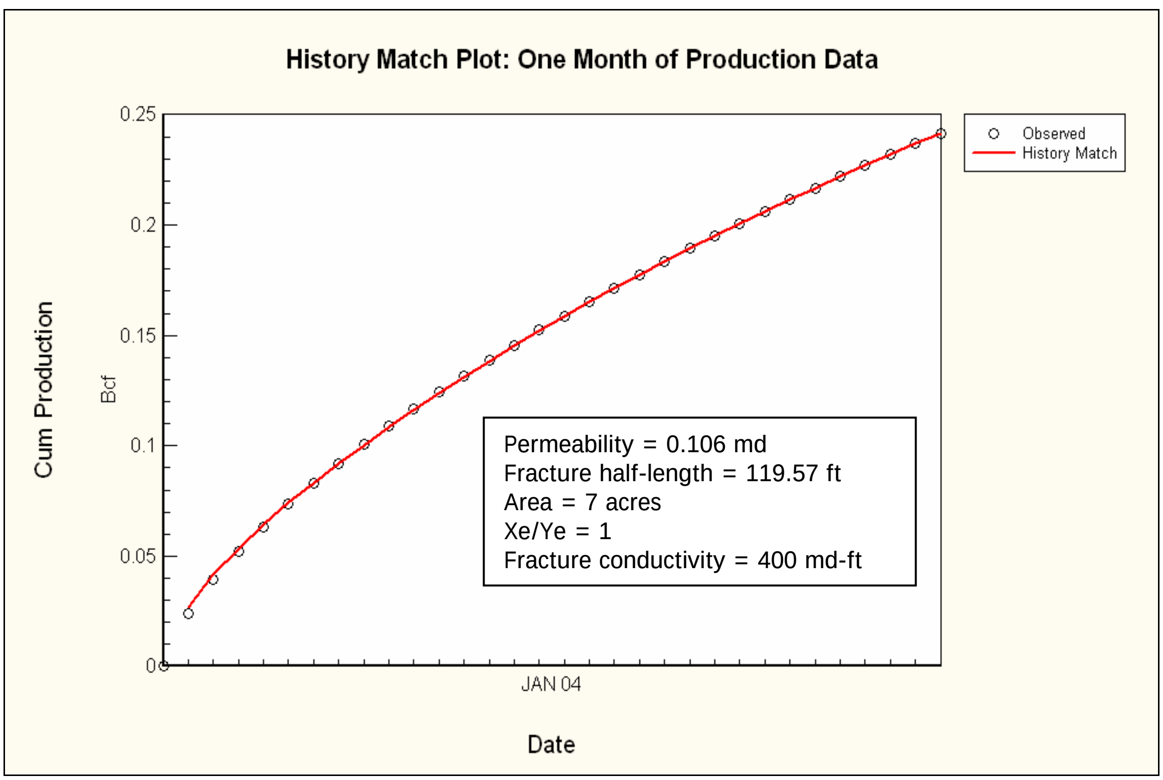

Fig. 4.41 *History Match Plot of the Cum Production for Reservoir Model Case No 98*

Fig 4.41 displays an excellent history match for case No 98. The permeability-thickness product calculated presented a reasonable estimation of actual permeability-thickness product with an error of 3%; the fracture half-length and the drainage area were underestimated by -66% and -96%, respectively.

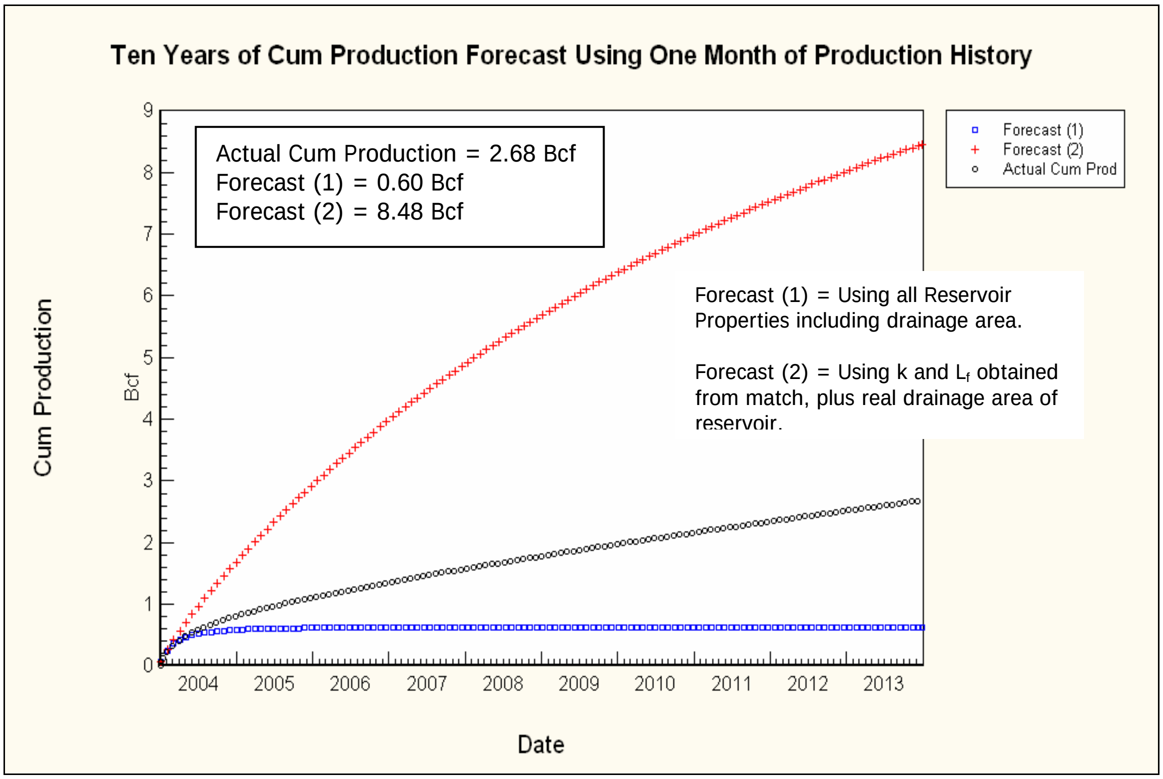

Fig 4.42 *Cumulative Gas Forecast for Case No 98*

Fig. 4.42 presents the reserves forecasts from simulation case No 98. Forecast (1) was underestimated by –78 % while Forecast (2) was overestimated by 216%. One might think that since the permeability-thickness product estimated from the history match was close to the one used in the simulation, Forecast (2) would yield a reliable 10 year of cumulative production forecast. However, in the ten-year gas production forecast calculation, the permeability is distributed evenly throughout the entire reservoir making the low permeability layer, which contains the majority of gas in place, have a larger permeability value than what it really had in the simulation that generated the data.

Case No 99 is the same to case No 93 and No 96, as shown in Table 4.18, except now we are only analyzing one month of production data

Table 4.18 *Reservoir Data for Simulation Case No 99*

Case N_o	99
$k_{(Top\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	100.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

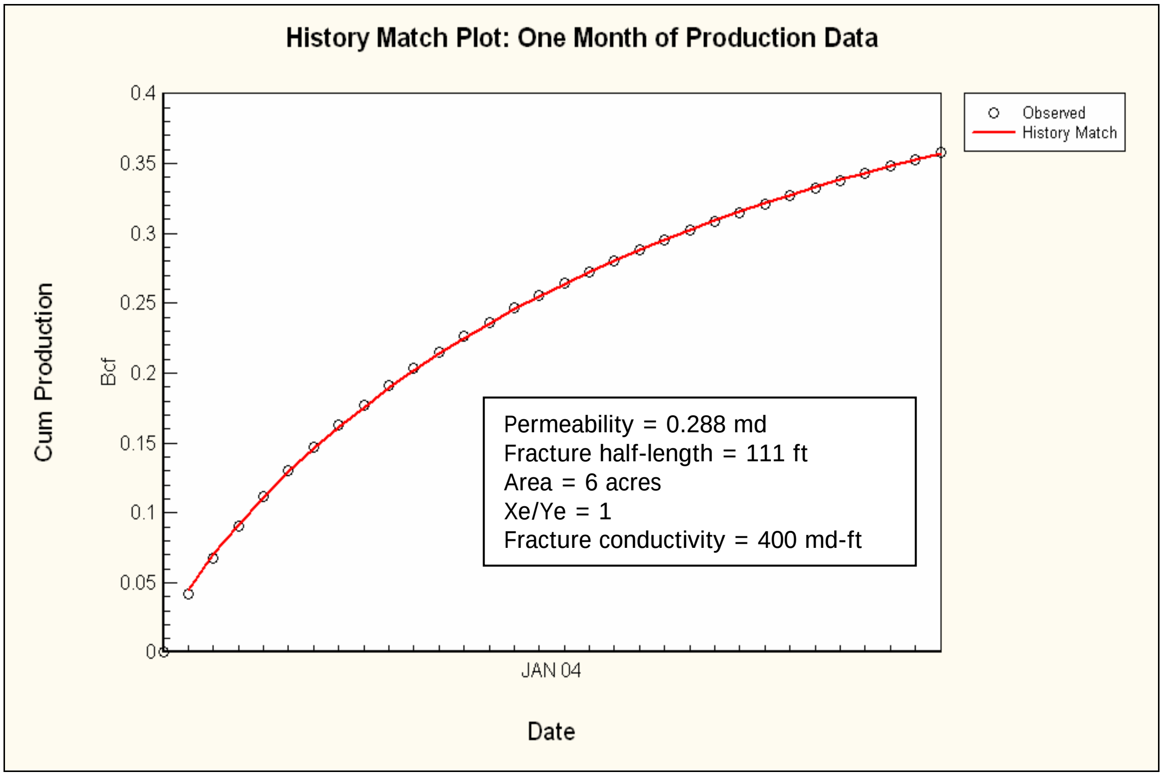

Fig. 4.43 *History Match Plot of the Cum Production for Reservoir Model Case No 99*

Fig 4.43 displays an excellent history match for case No 99. However, the permeability-thickness product, the fracture half-length, and the drainage area do not resemble the input values used in the simulation and were underestimated by -71%; -68%, and -96%, respectively.

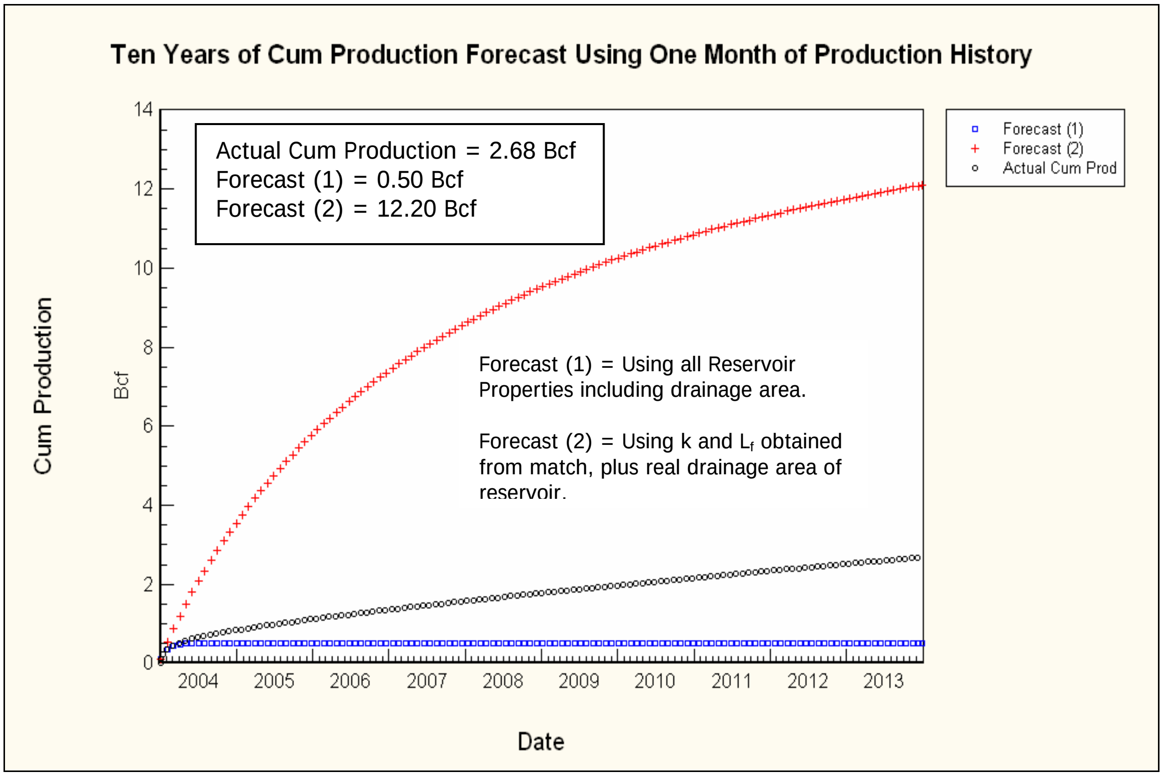

Fig 4.44 *Cumulative Gas Forecast for Case No 99*

Fig. 4.44 displays the ten-year gas production forecast for case No 99. Forecast (1) was underestimated by 81% because the drainage area was too small while Forecast (2) was overestimated with an error of 355 % because the equivalent single-layer model permeability was too large.

A summary of the results from case No 91-99 can be found on the table on p. 130, and the significance of the results are discussed in CHAPTER V of this thesis.

4.4 Scenario Three: Simulation Results

4.4.1 Production History = 36 months

Case No 142 is for Scenario three which is a three-layer reservoir where the top and bottom layers present a drainage area of the same magnitude and a low and a medium permeability values, respectively. The middle layer, on the other hand, has high permeability value and a limited drainage area compared to the low and medium permeability layers. Table 4.19 shows the reservoir data for the simulation case No 142. Again, the low short term production rates are dominated essentially by the high and medium permeability layers which most of the gas in place is in the low permeability layer.

Table 4.19 *Reservoir Data for Simulation Case No 142*

Case N_o	142
$k_{(Top\ Layer)}$, md	0.1
$k_{(Middle\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Middle\ Layer)}$, md	5
$h_{(Bottom\ Layer)}$, ft	85
kh, md-ft	50.85
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
$A_{(Middle\ Layer)}$, acres	20
OGIP, Bcf	15.7
L_f, ft	350

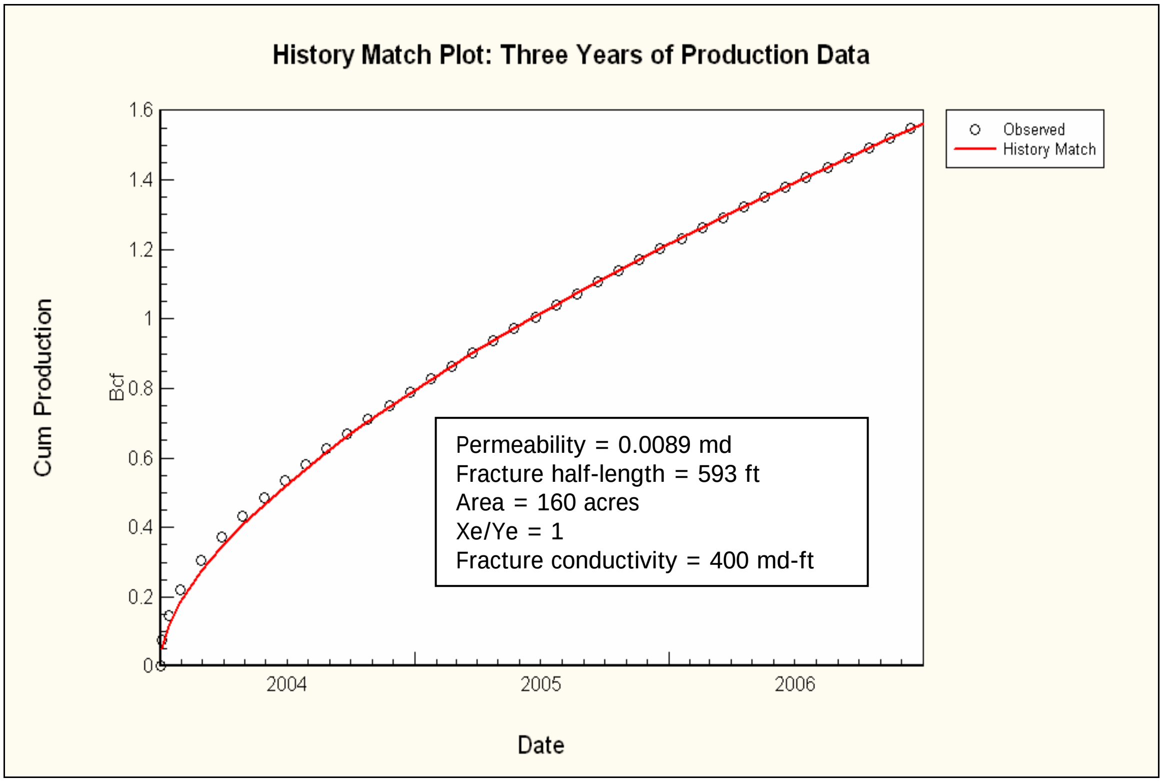

Fig. 4.45 *History Match Plot of the Cum Production for Reservoir Model Case No 142*

The history match for case No 142 from Table A.3 did not match exactly during early time as shown in Fig. 445; however, the match presents a reasonable overall match of the observed data. The permeability-thickness product (*kh*) for this history match does not correspond to the permeability-thickness used in the simulation model. The estimated value of kh was 0.89md-ft and the actual value used to generate the production data was 50.85md-ft. Once again, the equivalent single-layer permeability obtained from the history match is smaller than the permeability of the low permeability layer. This phenomenon is due to the fact that in three years the high permeability layer which has a limited areal extent has depleted completely, In addition, the medium permeability layer which is only 5 feet thick has depleted partially; therefore, the permeability-thickness product calculation starts being controlled principally by the permeability value of the low permeability layer which covers only 85% of the total thickness. The fracture half-length was overestimated by 70%. Since the single-layer model permeability estimated for the three-layer reservoir model was too low, the drainage area calculation estimated by the match tended to be larger than the maximum magnitude of the layers to compensate for the high decline rate. Therefore, a constrain of 160 acres was fixed for the analysis of the case.

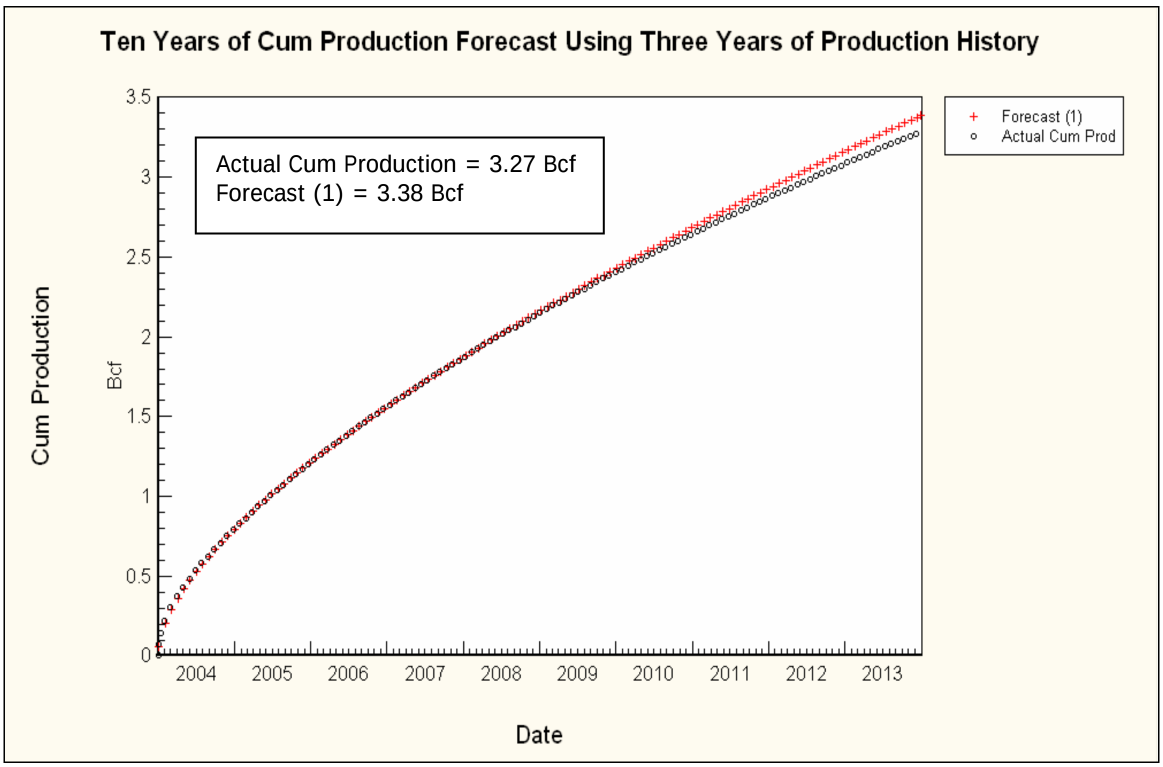

Fig 4.46 *Cumulative Gas Forecast for Case No 142*

Although, the values for reservoir properties obtained in the history match shown in Fig. 4.46 do not represent the values used in the simulation, the ten-year gas production forecast has only a +3% error with respect to the actual cumulative production. This suitable forecast is due to the large amount of gas in place predicted by the analysis with such a large drainage area.

4.4.2 Production History = 12 months

Case No 143 is identical to case No 142, as shown in Table 4.20, except now we are only analyzing twelve months of production data.

Table 4.20 *Reservoir Data for Simulation Case No 143*

Case N_o	143
$k_{(Top\ Layer)}$, md	0.1
$k_{(Middle\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Middle\ Layer)}$, md	5
$h_{(Bottom\ Layer)}$, ft	85
kh, md-ft	50.85
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
$A_{(Middle\ Layer)}$, acres	20
OGIP, Bcf	15.7
L_f, ft	350

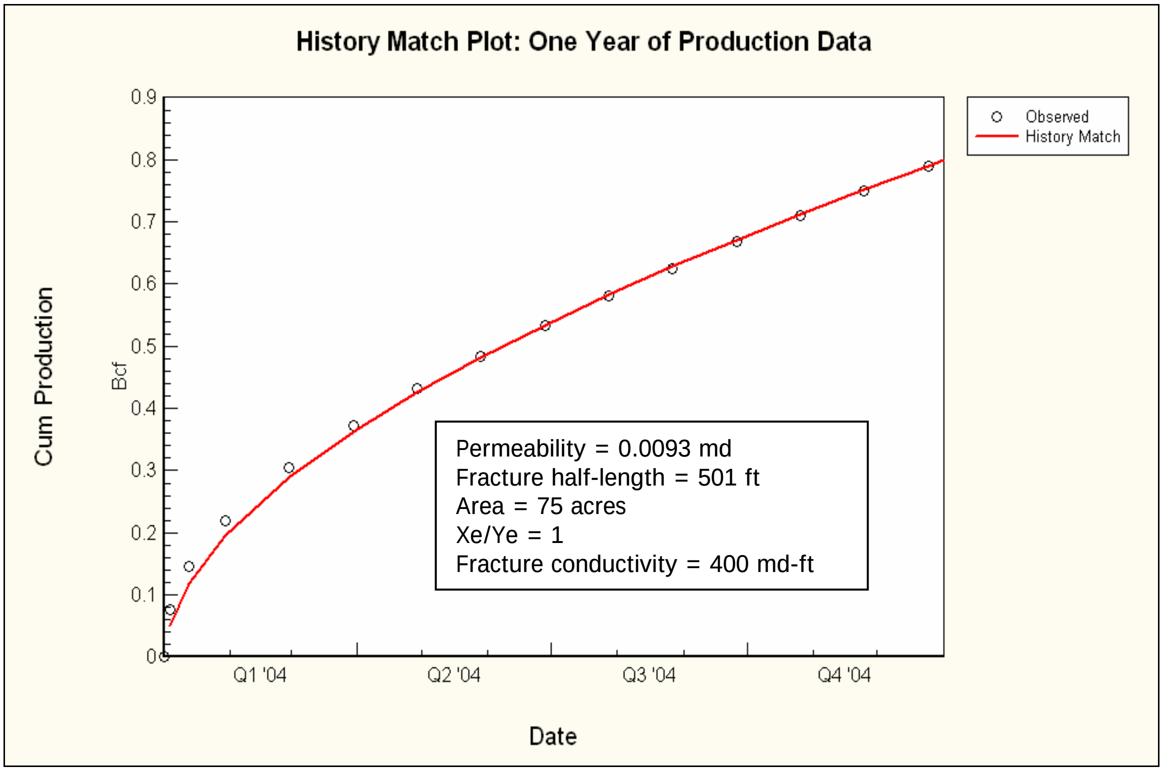

Fig. 4.47 *History Match Plot of the Cum Production for Reservoir Model Case No 143*

Once again, the history match for case No 143 from Table A.3 did not match perfectly in the early time due to the high gas production from the middle layer as shown in Fig. 4.47. Once the middle layer has been depleted, the data start to match better. The permeability-thickness product for this history match does not correspond to the permeability-thickness product used in the simulation model; this value was underestimated by 98%. The fracture half-length was overestimated by 43%. The history match gave a drainage area of the well of 75 acres, which was 50% of the values used in the simulation to generate the synthetic production data.

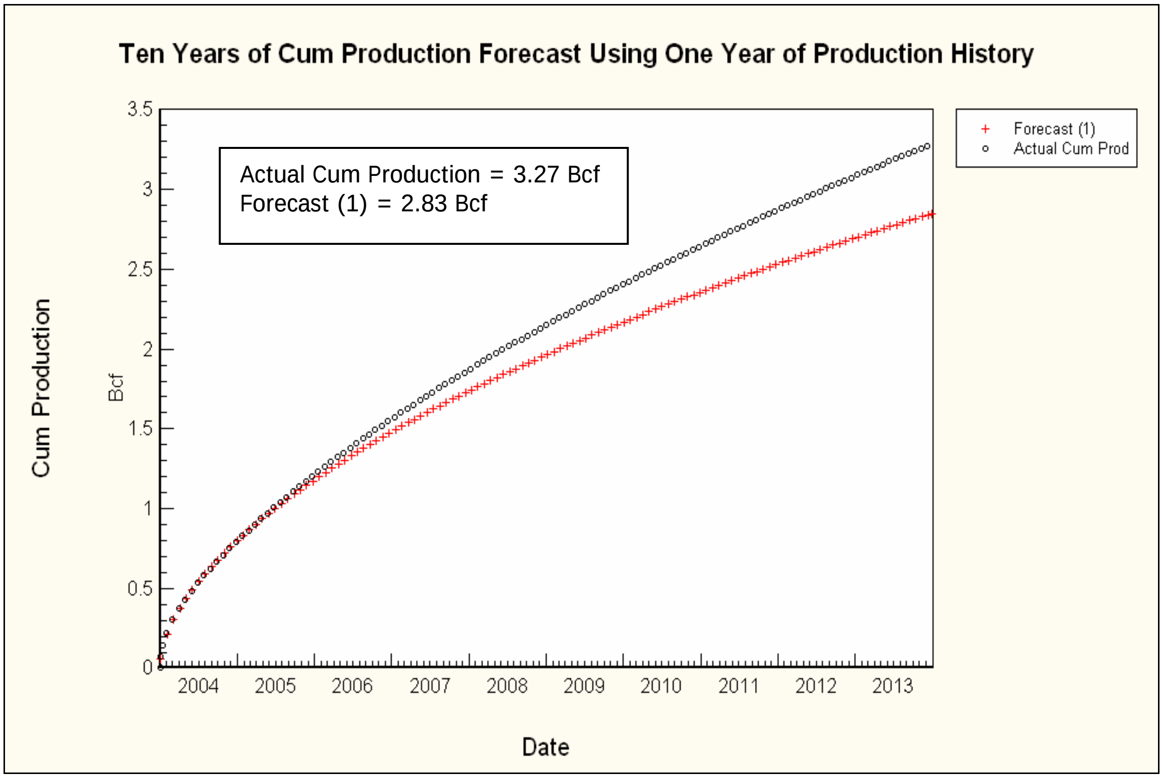

Fig 4.48 *Cumulative Gas Forecast for Case No 143*

Although, the values for reservoir properties obtained in the history match shown in Fig. 4.48 do not represent the values used in the simulation, the 10 year cumulative production forecast has -13% error with respect to the actual cumulative production.

4.4.3 Production History = 1 month

Case No 144 is identical to case No 142 and No 143, as shown in Table 4.21, except now we are only analyzing one month of production data.

***Table 4.21** Reservoir Data for Simulation Case No 144*

Case N_o	144
$k_{(Top\ Layer)}$, md	0.1
$k_{(Middle\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Middle\ Layer)}$, md	5
$h_{(Bottom\ Layer)}$, ft	85
kh, md-ft	50.85
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
$A_{(Middle\ Layer)}$, acres	20
OGIP, Bcf	15.7
L_f, ft	350

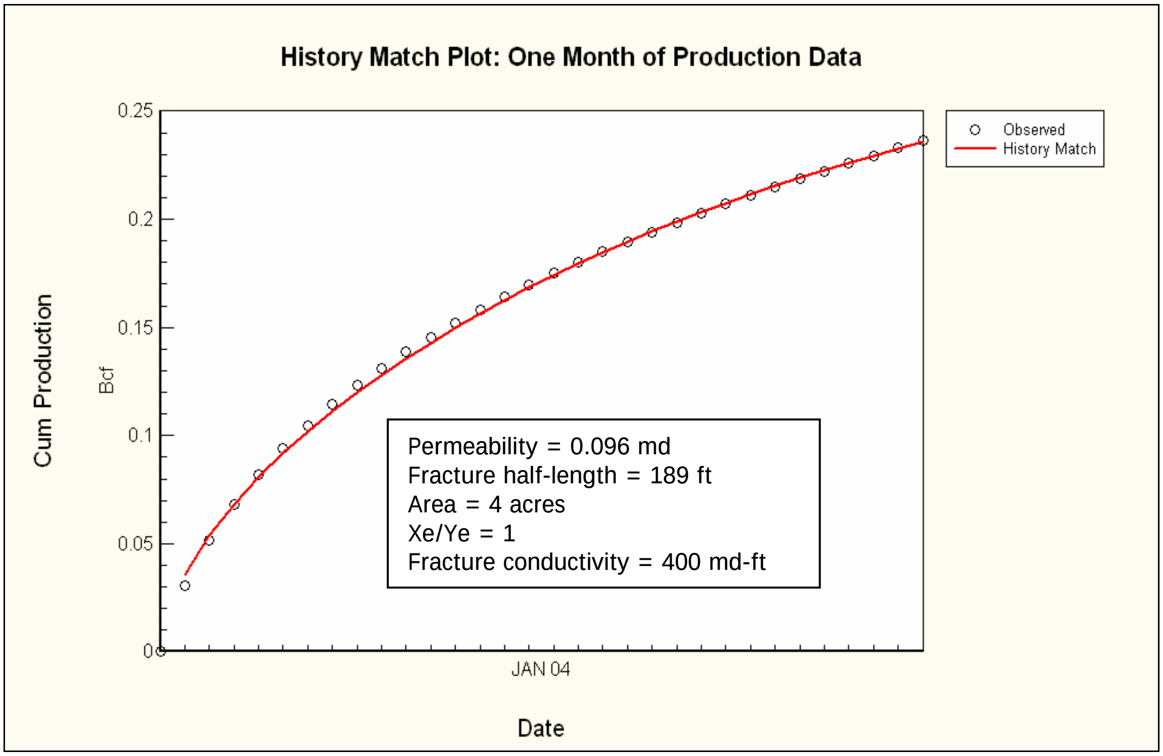

Fig. 4.49 *History Match Plot of the Cum Production for Reservoir Model Case No 144*

Fig. 4.49 displays the history match for case No 144. The match is reasonable; however, the results from this match do not fit the reservoir properties used in the simulation. The permeability-thickness was underestimated by 80%; however, the permeability value resulting from the single-layer reservoir model match was increased by one order of magnitude from the previous case where one year of production data was used in the analysis. The reason is that in one month the flow rate is mostly dominated by the high permeability layer, therefore, making the match estimate a larger permeability value.

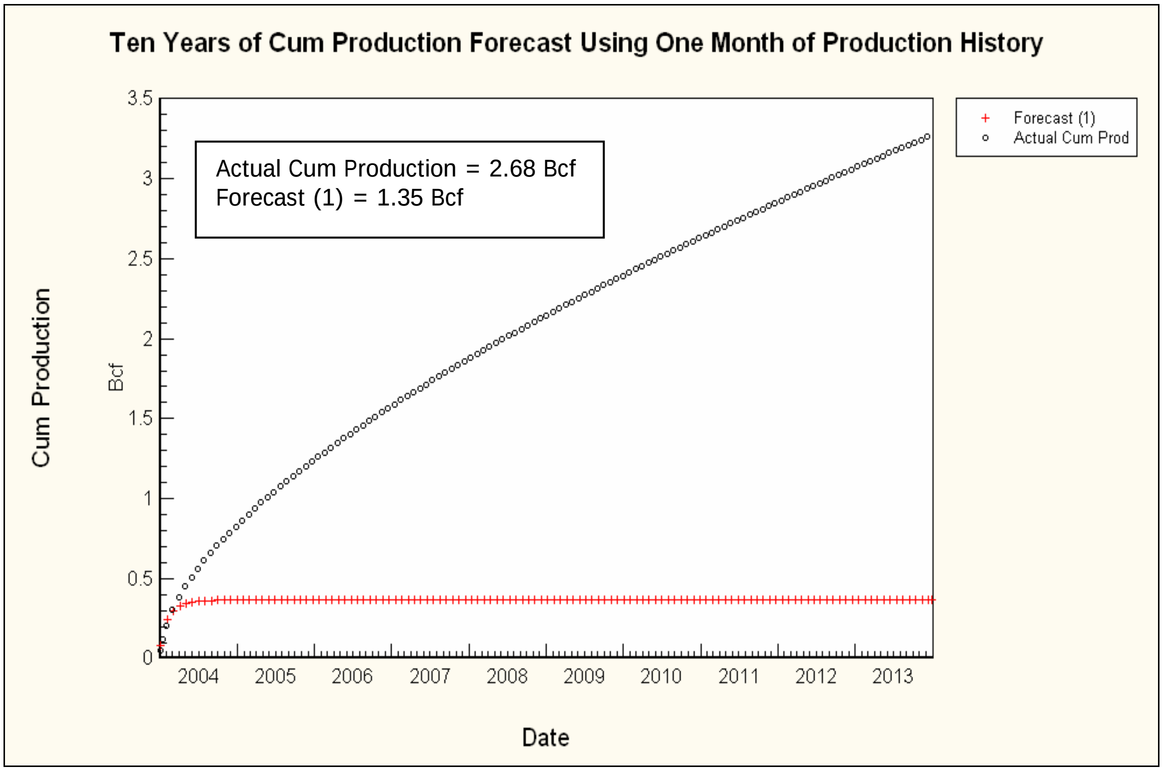

Fig 4.50 *Cumulative Gas Forecast for Case No 144*

Since in one month the pressure transient has only reached a small fraction of the drainage area of the reservoir, the drainage area was estimated to be only 4 acres. Due to this small drainage area estimate, Forecast (1) was underestimated by 90% as shown in fig. 4.50.

A summary of the results from case No 142-144 can be found on the table on p. 138, and the significance of the results are discussed in CHAPTER V of this thesis.

4.5 Multi-layer Production History Analysis

In this section, we demonstrated that it is possible to correctly analyze production data in tight gas reservoirs which include various layers with different permeability values, gas in place volumes and areal extents if one uses a multi-layer model; however, a detailed reservoir description has to be available. The description is obtained by integrating log analysis, core data, build-up tests, production logs and geological information about the reservoir. Such a description is costly and time-consuming. In addition, an expert petroleum engineer must be trained to perform the analysis. As such, many companies do not correctly analyze production data from their layered, tight gas reservoirs.

Three years of production data for simulation cases No 11, 92, and 142 were analyzed using a multi-layer description with a new fully-coupled, single-well analytical simulator (PMT.X) for multilayer unconventional gas reservoirs.[39] Since production data alone do not provide all information necessary to estimate individual layer properties in such complex layered reservoirs, the analytical simulator requires production logs to allocate the total flow rate within the layers at several points in time, and thus, representing each layer as a separate single-layer analytical reservoir model. Three synthetic production logs at 360, 720, and 1050 days were generated for each case for the production data analyses. The production log data were history matched simultaneously with the gas flow rate data using a multi-layer description model as described in Sections 3.6.1-3.6.3. Open circles were used to represent the observed production data and a solid lines were used to represent the production data match.

Ten years of gas production forecast using the reservoir properties calculated from the history matches were also graphed to demonstrate the error that occurs when multi-layer modeling methods are used to history match production data and to forecast well performance in typical layered tight gas reservoirs. Two different forecasts for ten years of gas production were plotted for each case run. **M-L Forecast (1)** is a forecast using all the reservoir properties calculated from the history match analysis including the drainage area. **M-L Forecast (2)** is a forecast using the permeability values (*k*) and fracture half-lengths (L_f) for each layer obtained from the match, plus the true drainage areas (*A*) of each layer. Once again, it is important to mention that the real drainage area is the well spacing assuming a blanket tight gas reservoir.

As mentioned in section 3.6.1, case No 11 is a two-layer reservoir model with the same drainage area for both layers. The bottom layer is a low permeability (0.01 md) interval that contains a significant amount of gas in place and is overlaid by a thin layer with a medium permeability value (1.0 md), as shown in Table 4.22.

Table 4.22 *Reservoir Data for Simulation Case No 11 for Multi-layer Production History Analysis*

Case N_o	11
$k_{(Top\ Layer)}$, md	1.0
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	5
$h_{(Bottom\ Layer)}$, ft	95
kh, md-ft	5.95
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
OGIP, Bcf	16.5
L_f, ft	350

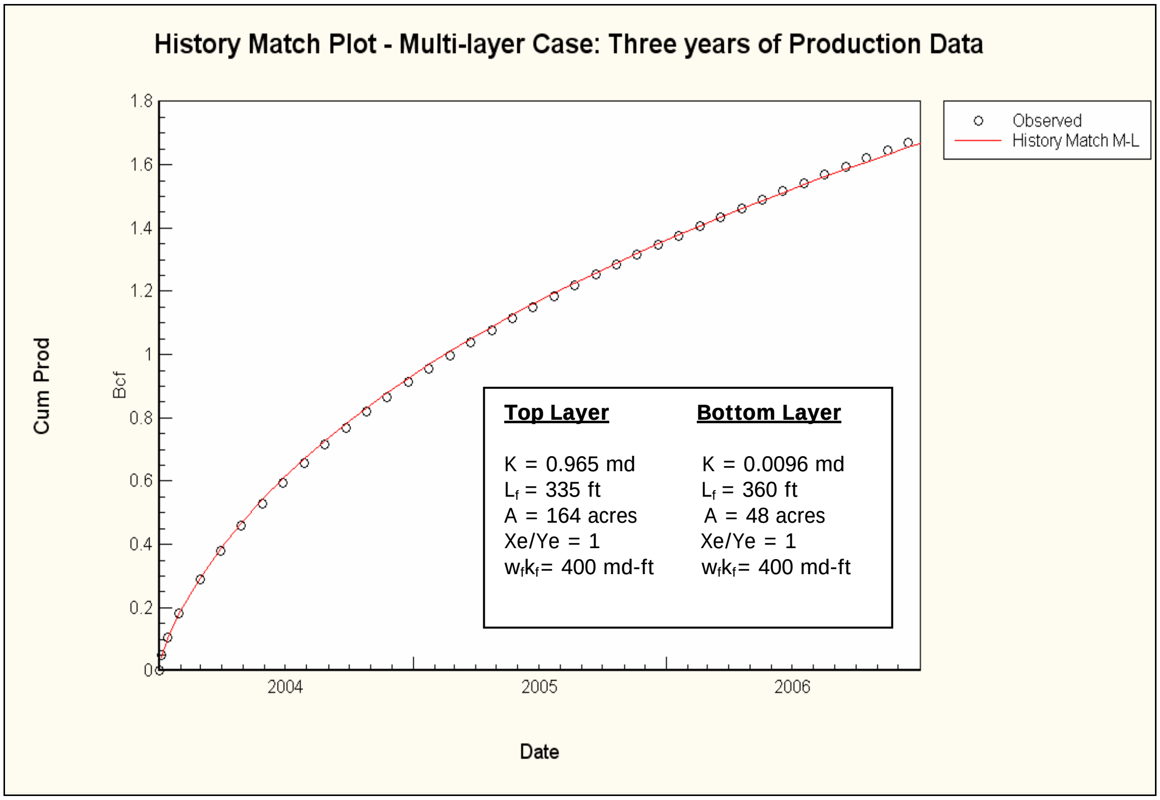

Fig. 4.51 *History Match Plot of the Cum Production for Reservoir Model Case No 11 Using a Multi-layer Description Model*

Fig. 4.51 exhibits the production history match for case No 11 from Table A.1. The production data for this case were analyzed using a two-layer model description with characteristics shown in Table 4.22. The plot shows a reasonable match for 3 years of production history. After matching the production logs and the production data simultaneously, a permeability-thickness product of 5.74 md-ft was estimated which represents an underestimation error of only -3.5% from the one used in the simulation (5.95 md-ft). The history match indicated an average fracture half-length (L_f) of 347 ft, which represents 1% error from the true fracture half-length (350 ft) of the simulation model. The drainage area estimated by the history match for the top layer agrees with the true drainage area of the simulation model. However, the drainage area estimated by the history match for the bottom layer is underestimated by 70% (48 acres vs. 160 acres). The underestimation of the drainage area of bottom layer caused again by the fact that in three years the flow was not affected by the boundaries of the reservoir.

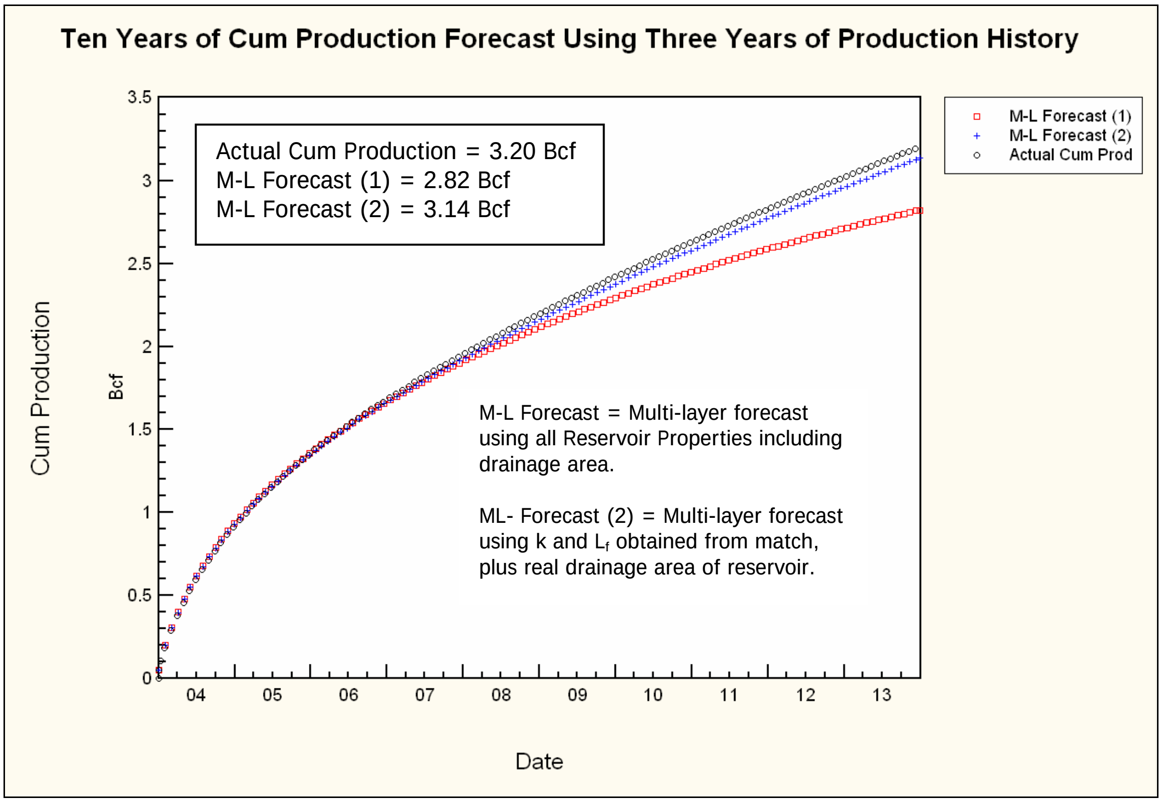

Fig. 4.52 *Cumulative Gas Forecast for Case No 11 Using a Multi-layer Description Model*

Fig. 4.52 displays ten years of gas production forecast for case No 11 using a multi-layer model description. M-L Forecast (1) was underestimated by 12% because the drainage area of the bottom layer, which contains the majority of gas in place, was underestimated by the history match. On the other hand, using the results obtained from the multi-layer analysis plus the real drainage area of the bottom layer, a reliable forecast with a -2% error is obtain, as shown in M-L Forecast (2).

Case No 92 is a two-layer reservoir model with a large, thick, low permeability (0.01 md) layer at the bottom overlaid by thinner, higher permeability (1.0 md) layer that presents a limited areal extent (40 acres) compared to that of the low permeability layer (160 acres), as shown in Table 4.23.

Table 4.23 *Reservoir Data for Simulation Case No 92 for Multi-layer Production History Analysis*

Case N_o	92
$k_{(Top\ Layer)}$, md	1.0
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Bottom\ Layer)}$, ft	90
kh, md-ft	10.9
$A_{(Top\ Layer)}$, acres	40
$A_{(Bottom\ Layer)}$, acres	160
OGIP, Bcf	15.24
L_f, ft	350

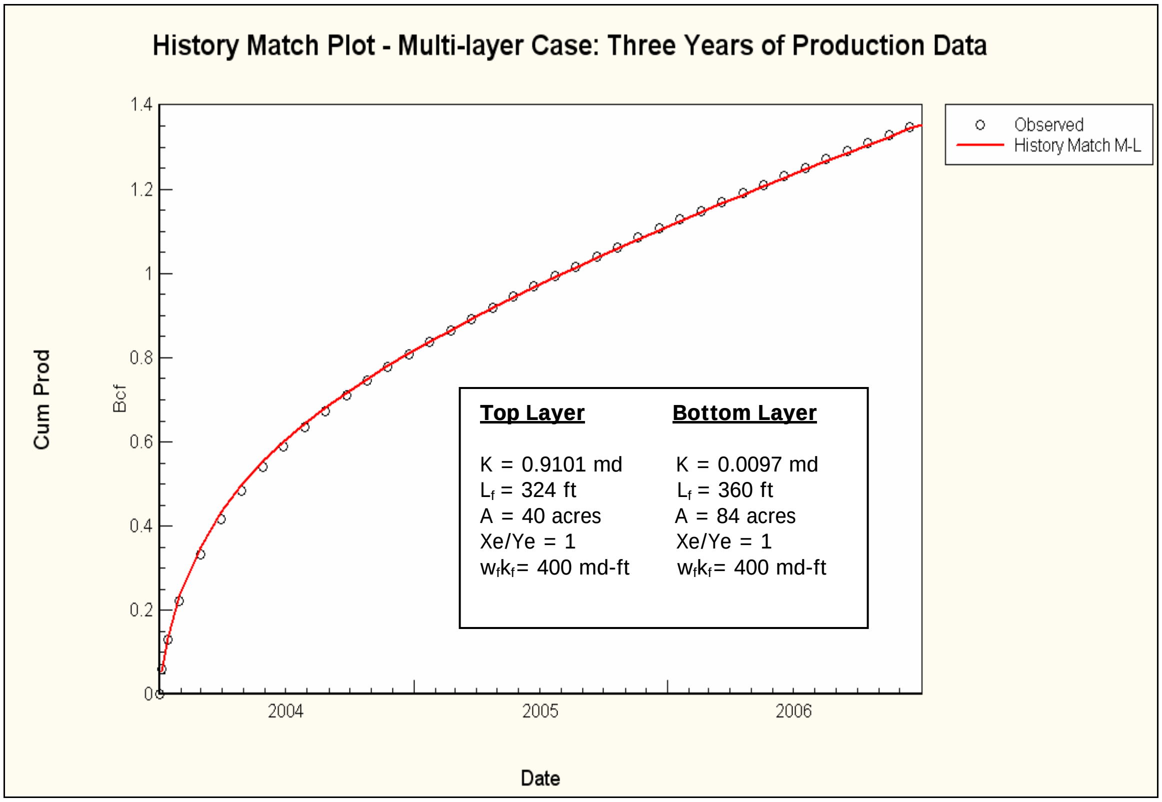

Fig. 4.53 *History Match Plot of the Cum Production for Reservoir Model Case No 92 Using a Multi-layer Description Model*

Fig. 4.53 shows the history match for case No 92, from Table A.2 using a multi-layer description model. Unlike the history match from case No 92 using a single-layer model, where the production data did not match unless the geometry of the reservoir was varied, by using a multi-layer model, the production data matches perfectly without varying the geometry of the reservoir. A permeability-thickness product of 10 md-ft was estimated which presents an error of -8.5% from the real permeability-thickness product used in the simulation (10.9 md-ft). The history match indicated an average fracture half-length (L_f) of 342 ft; it represents 3% error from the true fracture half-length (350 ft) of the simulation model. The drainage area estimated by the history match for the top layer agrees with the true drainage area of the simulation model (40 acre vs. 40 acres). However, the drainage area estimated by the history match for the bottom layer is underestimated by -47% (84 acres vs. 160 acres). Once again, the transient flow in the bottom layer caused the drainage area to be underestimated.

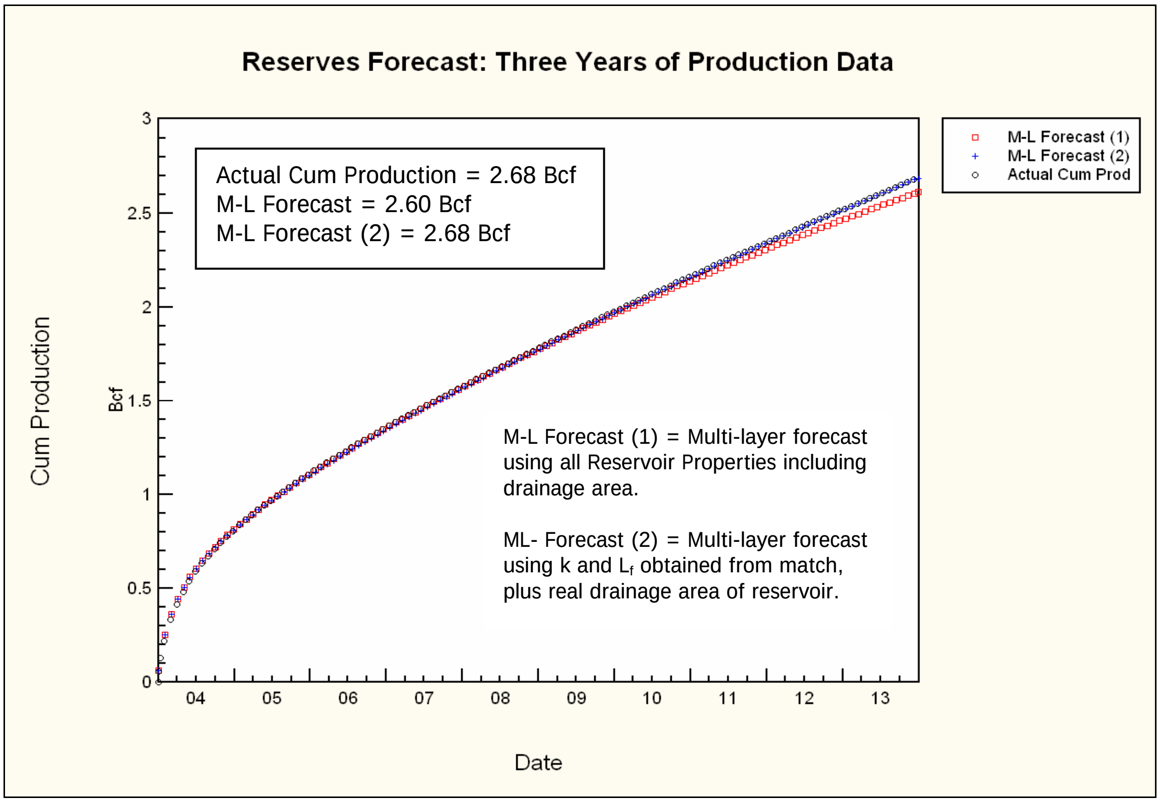

Fig. 4.54 *Cumulative Gas Forecast for Case No 92 Using a Multi-layer Description Model*

Fig. 4.54 shows ten years of gas production forecast from case No 92 using a two layer model description. M-L Forecast (1) and M-L Forecast (2) both show a very good forecast estimate of gas production for ten years. One might think that because the drainage area of the bottom layer was underestimated by one half, M-L forecast was going to be underestimated, however, in ten years the system will only produce 17% of its total gas in place, and the drainage area obtained by the history match for the bottom layer (84 acres) was large enough to be able to contain at least 20% of its total gas in place.

Case No 142 is a three-layer reservoir model with the same drainage area for the top and bottom layers (160 acres) and a layer with smaller drainage area (20 acres) in the middle. The middle layer has a high permeability value (10 md), while the bottom and top layers present a low (0.01 md) and a medium (1.0 md) permeability values, respectively, as can be seen in Table 4.24. The bottom layer, however, is a thick interval that contains a significant amount of the gas in place.

Table 4.24 *Reservoir Data for Simulation Case No 142 for Multi-layer Production History Analysis*

Case N_o	142
$k_{(Top\ Layer)}$, md	0.1
$k_{(Middle\ Layer)}$, md	10
$k_{(Bottom\ Layer)}$, md	0.01
$h_{(Top\ Layer)}$, ft	10
$h_{(Middle\ Layer)}$, md	5
$h_{(Bottom\ Layer)}$, ft	85
kh, md-ft	50.85
$A_{(Top\ \&\ Bottom\ Layers)}$, acres	160
$A_{(Middle\ Layer)}$, acres	20
OGIP, Bcf	15.7
L_f, ft	350

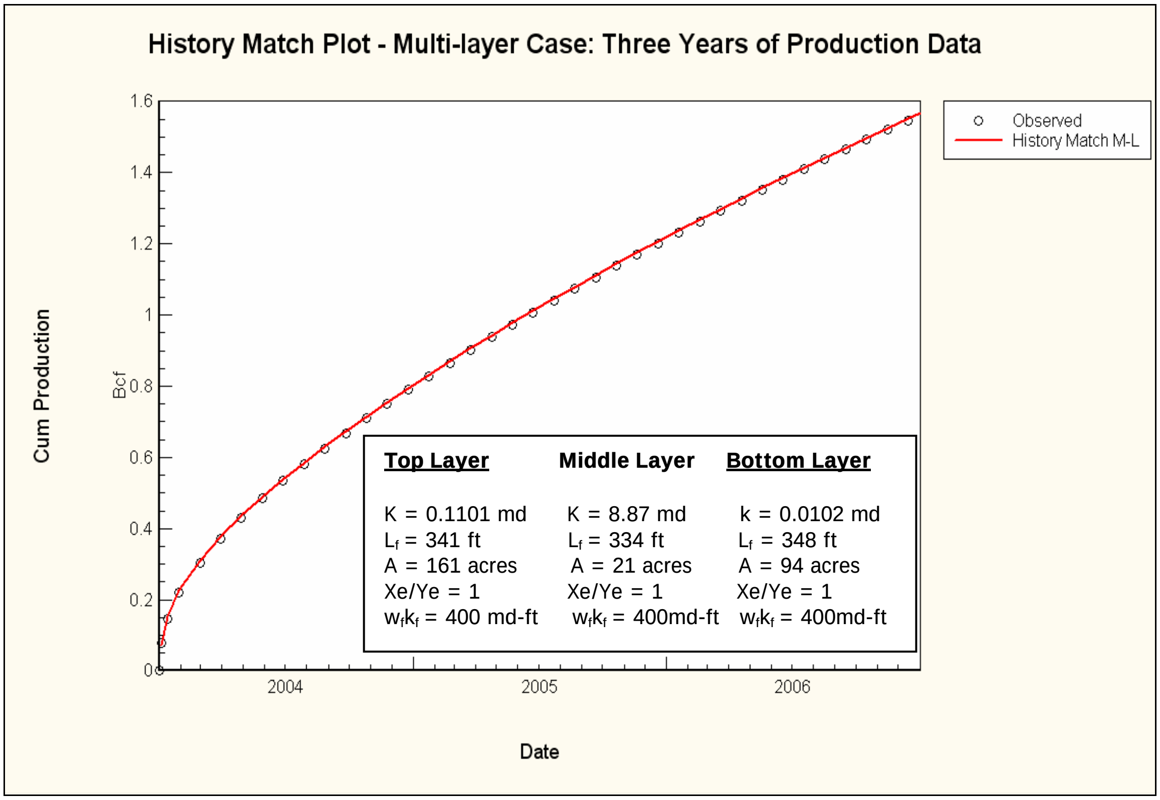

Fig. 4.55 *History Match Plot of the Cum Production for Reservoir Model Case No 142 Using a Multi-layer Description Model*

Fig. 4.55 displays a perfect history match for case No 142 using a multi-layer description model. The permeability-thickness product (46.32 md-ft vs. 50.85 md-ft) and the fracture half-length (341 ft vs. 350 ft) obtained from the match are in a good agreement with the true values used in the simulation model with errors of -9% and 3%, respectively. The drainage area for the top (161 acres vs. 160 acres) and middle (21 acres vs. 20 acres) layers also agree with the true values; however, the drainage area of the bottom layer was underestimated by 41% (94 acres vs. 160 acres).

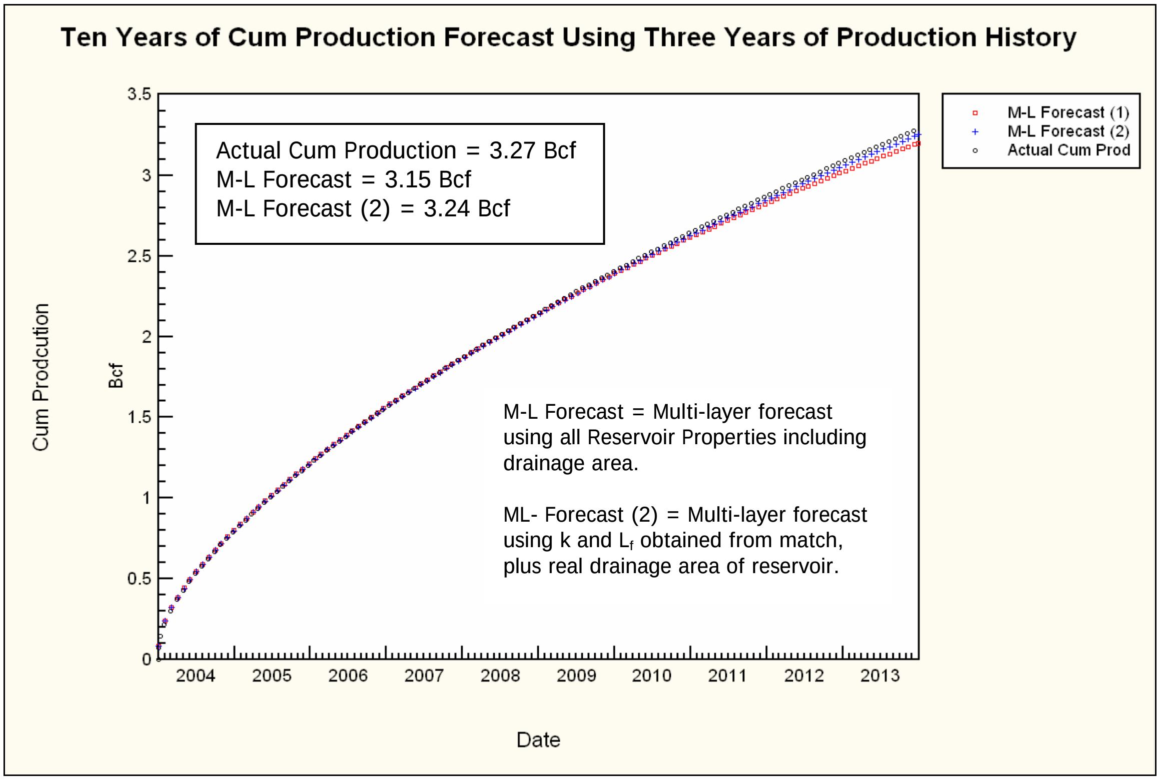

Fig. 4.56 *Cumulative Gas Forecast for Case No 142 Using a Multi-layer Description Model*

Fig. 4.56 shows the ten-year gas production forecast from case No 142 using a multi-layer description model. M-L Forecast (1) and M-L Forecast (2) present reliable ten years of production forecast estimates falling within 4% and 1% error, respectively.

CHAPTER V
DISCUSSION OF RESULTS

5.1 Discussion of Simulation Case Results for Scenario One

Again, scenario one is a two-layer tight gas reservoir model with the same drainage area for both layers, but different layer thickness and reservoir properties. The layer thickness for the top layer is 5 ft and for the bottom layer is 95 ft; the total net pay for the reservoir is 100 ft.

Table 5.1 summarizes the results for the cases in Scenario one explained in the CHAPTER IV. Tables of history match results for the simulation cases for scenario one that were not explained in the previous section can be found in APPENDIX B (Tables B1-B8). Table 5.1 shows the values for permeability-thickness product, fracture half-length, and drainage area calculated by the history match analyses. Table 5.1 also shows the error for 10 years of cumulative gas production for the reservoir model when forecasted with the values calculated from the history match analysis.

The contrast in layer properties in a tight gas reservoir drastically affects the history match results. From the analysis in Table 5.1, one can see that the degree of underestimation for the permeability-thickness product calculated by the history match will increase as the contrast of permeability in the layers increases. Let's consider cases No 10, No 11, and No 12, where we have history matched three years of gas flow rate data in each case. The permeability-thickness product for case No 10, which has a small permeability contrast, is about 90% of the actual permeability-thickness product (kh) (1.27 md-ft vs. 1.45 md-ft). On the other hand, permeability-thickness products for cases

No 11 and No 12 which have medium and large permeability contrasts had more error. For case No 11, the computed kh was 1.33 md-ft and the actual was 5.95 md-ft. For case No 12, the computed value was 2.73 md-ft which the input value was 50.95md-ft. Therefore, those values of kh only account for 22% and 5% of the actual kh, respectively. Although, the permeability-thickness product was underestimated in all the cases, the permeability value, when distributed evenly throughout the entire net pay thickness, as one must do when using a single-layer model, will still be larger than the *true permeability value in the low permeability zone* where the majority of gas in place is located. Therefore, the ten-year gas production will be overestimated if the correct drainage area is used to generate the forecast.

In these runs, when three years of production data are analyzed, the high permeability layers (case No 12) tend to be partially depleted during the three year period. Even though the early gas flow rate is dominated by the high permeability layer, the gas production during the last year or more is mainly coming from the low permeability layer. Thus, the 'kh' from the match of three years of production data from case No 12 is lower than the true kh because the match hast to match the late time data, which is dominated by the low permeability layer. As will be seen in cases No 15 and No 18, which are identical to case No 12 except less production data are analyzed, the estimated values of kh from the history matches are actually better because the early time production data are affected more by the high permeability layer production.

Table 5.1 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 10-18*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	5	160	1.0	5	160	10	5	160
Bottom Layer:	0.01	95	160	0.01	95	160	0.01	95	160
Three Years of Production Data									
		Case 10			**Case 11**			**Case 12**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	1.27	-12.41	5.95	1.33	-77.65	50.95	**2.73**	-94.64
Lf, (ft)	350	341	-2.57	350	545	55.71	350	**483**	38.00
A, (acres)	160	61	-61.88	160	38	-76.25	160	**26**	-83.75
Forecast 1, (Bcf)	2.96	2.8	-5.41	3.2	2.61	-18.44	3.21	**2.23**	-30.53
Forecast 2, (Bcf)	2.96	3.15	6.42	3.2	4.19	30.94	3.21	**6**	86.92
One Year of Production Data									
		Case 13			**Case 14**			**Case 15**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	1.33	-8.28	5.95	3.33	-44.03	50.95	**5.29**	-89.62
Lf, (ft)	350	328	-6.29	350	243	-30.57	350	**403**	15.14
A, (acres)	160	61	-61.88	160	24	-85.00	160	**18**	-88.75
Forecast 1, (Bcf)	2.96	2.56	-13.51	3.2	2.09	-34.69	3.21	**1.56**	-51.40
Forecast 2, (Bcf)	2.96	3.15	6.42	3.2	5.21	62.81	3.21	**8.1**	152.34
One Month of Production Data									
		Case 16			**Case 17**			**Case 18**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	2.67	84.14	5.95	7.04	18.32	50.95	28.67	-43.73
Lf, (ft)	350	212	-39.43	350	115	-67.14	350	72	-79.43
A, (acres)	160	6	-96.25	160	8	-95.00	160	11	-93.13
Forecast 1, (Bcf)	2.96	0.51	-82.77	3.2	0.6	-81.25	3.21	0.9	-71.96
Forecast 2, (Bcf)	2.96	4.29	44.93	3.2	6.96	117.50	3.21	11.6	261.37

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

It appears that the drainage area of the low permeability layer will always be underestimated if the data collected are still in the transient flow period in the layers that contain the bulk of the gas in place. In other words, if the pressure transient has not yet reached the boundaries of the reservoir, the drainage area calculated by the history match will be essentially the areal extent that the transient pressure had reached at the time the data were collected to do the history match analysis. For instance, the drainage area of the well calculated by the history match for cases No 11, No 14, and No 17, as shown in Table 5.1, decreased from 38 to 24 to 8 acres, respectively, as the amount of production data used in the history match decreased. It was also found, in all the cases, that the contrast in permeability within the layers also affects the estimation of drainage area for the reservoir system. As the permeability contrast increases within the layers, analyzing the same amount of production data, the computed value of drainage area decreases. For instance, in Table 5.1, one can notice that drainage area of the well in cases No 10, No 11 and, No 12 decreases from 61 to 38 to 26 acres, respectively, as the permeability in the high permeability layer is increased.

In cases No 12 and, No 15, where the permeability within the layers varied up to three orders of magnitude, the data did not match properly in the early time because of the rapid decline rate dominated by high permeability layer. However, it was found that the data in these cases could be matched very well by varying the geometry of the drainage area or the aspect ratio. All the synthetic data were generated in Eclipse using a square reservoir grid. However, we could match the multilayer, square grid results with a single-layer, rectangular grid, which of course, is totally incorrect. Some reservoir engineers, in their attempt to match production data in multi-layer tight gas reservoirs, are tempted to change the geometry of the drainage area of the wells, trying to match data from a complex reservoir with a simple model. However, the final result of the history match is often a bogus description of the reservoir system that will lead to erroneous conclusions regarding the amount of gas to be produced in the future and sometimes, the match can cause one to reach incorrect conclusions concerning the local geology. It is a classic case of doing two things wrong (single layer vs. multilayer and rectangular vs. square shaped drainage area) in order to get a “match”.

The fracture half-lengths for the simulation cases also present high degrees of variability, either overestimating or underestimating the actual value of the fracture half-length used in the simulation. However, there is not a definite trend visible in the results that would tell us when these values will be overestimated or underestimated. For instance, the history match analysis performed for case simulations No 13 and No 14, which have a small and a moderate permeability contrasts, estimated a fracture half-length of 328 and 243 ft, respectively. These values underestimated the fracture by 7% and 31% correspondingly. In contrast, the history match analysis performed for case No 15, which has a large degree of permeability contrast within the layers, was overestimated by 15% (403 ft vs. 350 ft). However, if the average permeability estimated for the multi-layer model was larger than the true permeability of the low permeability layer that contains the bulk of gas in place, the fracture half-length was underestimated to balance out the high rate that the high value of permeability estimated would make produce. On the other hand, if the estimated average permeability for the multilayer model was lower than the low permeability layer, the fracture half-length was overestimated to account for the high flow rate in the early time contributed by the high permeability layer.

It must be remembered that the results explained above are valid for the limited data used in this research study as shown in CHAPTER III of this thesis. However, the same conclusion would probably be reached using different sets of similar input data. Because of the high degree of variability in tight gas reservoirs, history matching production data using single-layer model descriptions will indeed produce incorrect values of permeability-thickness product, fracture half-length and drainage area. Using these values of reservoir properties to forecast reserves, will give misleading estimates of gas production potential.

Figs 5.1-5.3 show the error one might expect for ten years of gas production forecasted using the history match results generated during this research. Fig. 5.1 is a graph of the error for the reservoir model with a small permeability contrast ($k_{layer\ 1}$= 0.1md and $k_{layer\ 2}$ = 0.01md) and a drainage area of 160 acres. Each line represents the error of either Forecast (1) or Forecast (2) for three different fracture half-lengths used in this research. As can be seen in Fig. 5.1, all Forecast (1) results underestimate the actual cumulative production due to underestimated drainage areas and small gas volumes estimated by the history match analysis. All Forecast (2) results overestimate the actual cumulative production because the average value of permeability is too large. However, after about 15 months of production, the ten-year gas production value for Forecast (1) results will yield reliable forecasts with an error falling within a 10% range. The error of cumulative production for 10 years in Forecast (2) results converges after 12 months of production data used for the history match analysis.

Fig. 5.2 displays the error for ten years of gas production for the reservoir model with a medium permeability contrast ($k_{layer\ 1}$= 1.0 md and $k_{layer\ 2}$ = 0.01md) and a drainage area of 160 acres. All Forecast (1) results underestimate the actual cumulative production due to small values for drainage area while all Forecast (2) results overestimate the actual cumulative production because the value of average permeability is too large. If one history matches only one month of production data and uses the all the results, including the calculated drainage area, to forecast gas production for 10 years, one will underestimate the value by up to 80%. However, if one uses the matched values with a month of production data and also uses the real drainage area of the well, one will overestimate the value by up to 135%. Reliable ten years of gas production under 10% error will not be achieved for these cases even when history matching 3 years of production data. For Forecast (1) results, the reason of not obtaining reliable forecasts even when 3 years of production data is available is because of the small drainage areas obtained by the matches, making the system have a small gas in place to be produced. On the other hand, for Forecast (2) results, the reason of not obtaining reliable forecasts is because of the large average permeability obtained by the match.

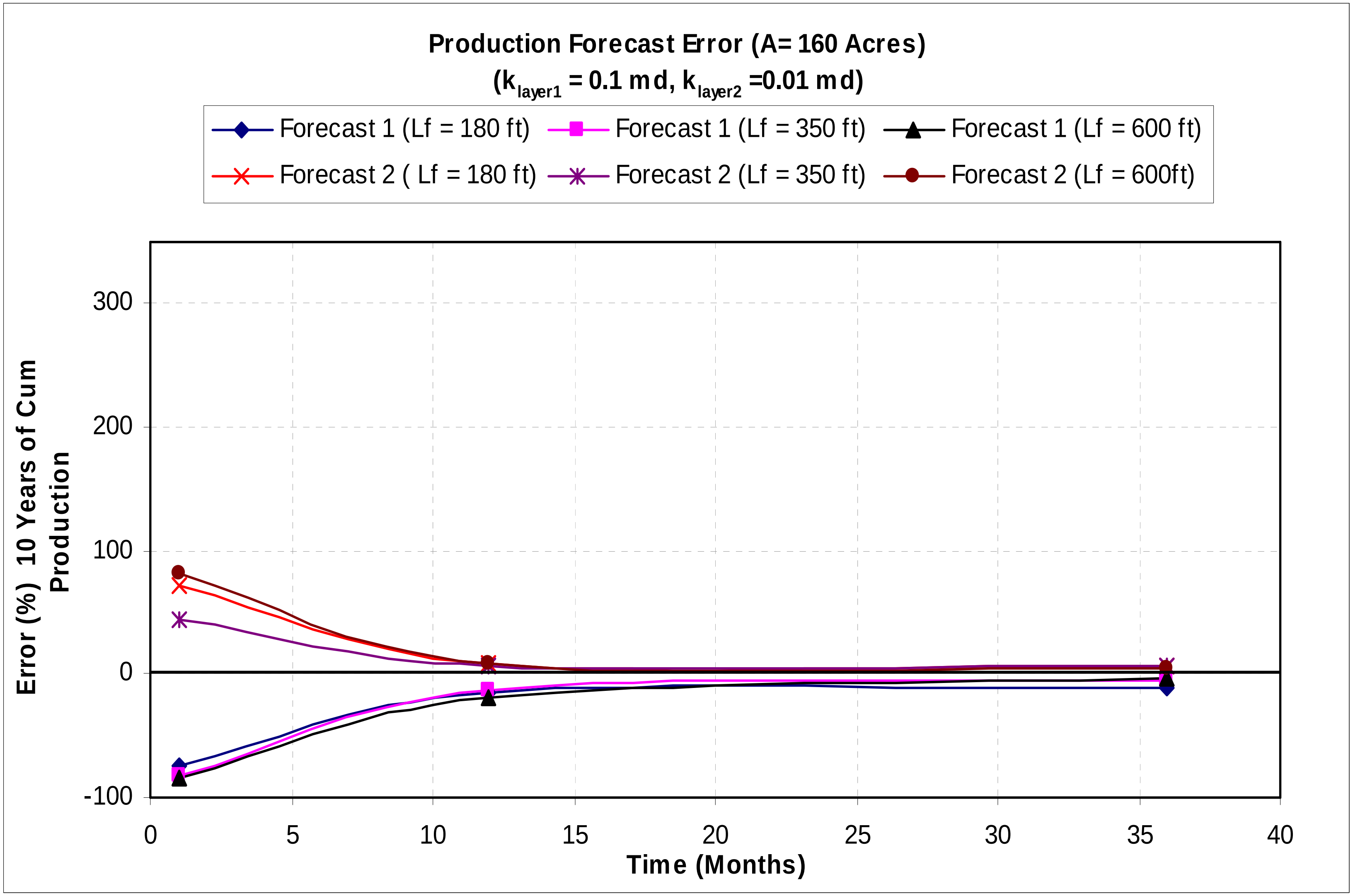

Fig 5.1 *Production Forecast Error Scenario One (A=160 acres, k_{layer1}= 0.1md, K_{layer2}=0.01 md)*

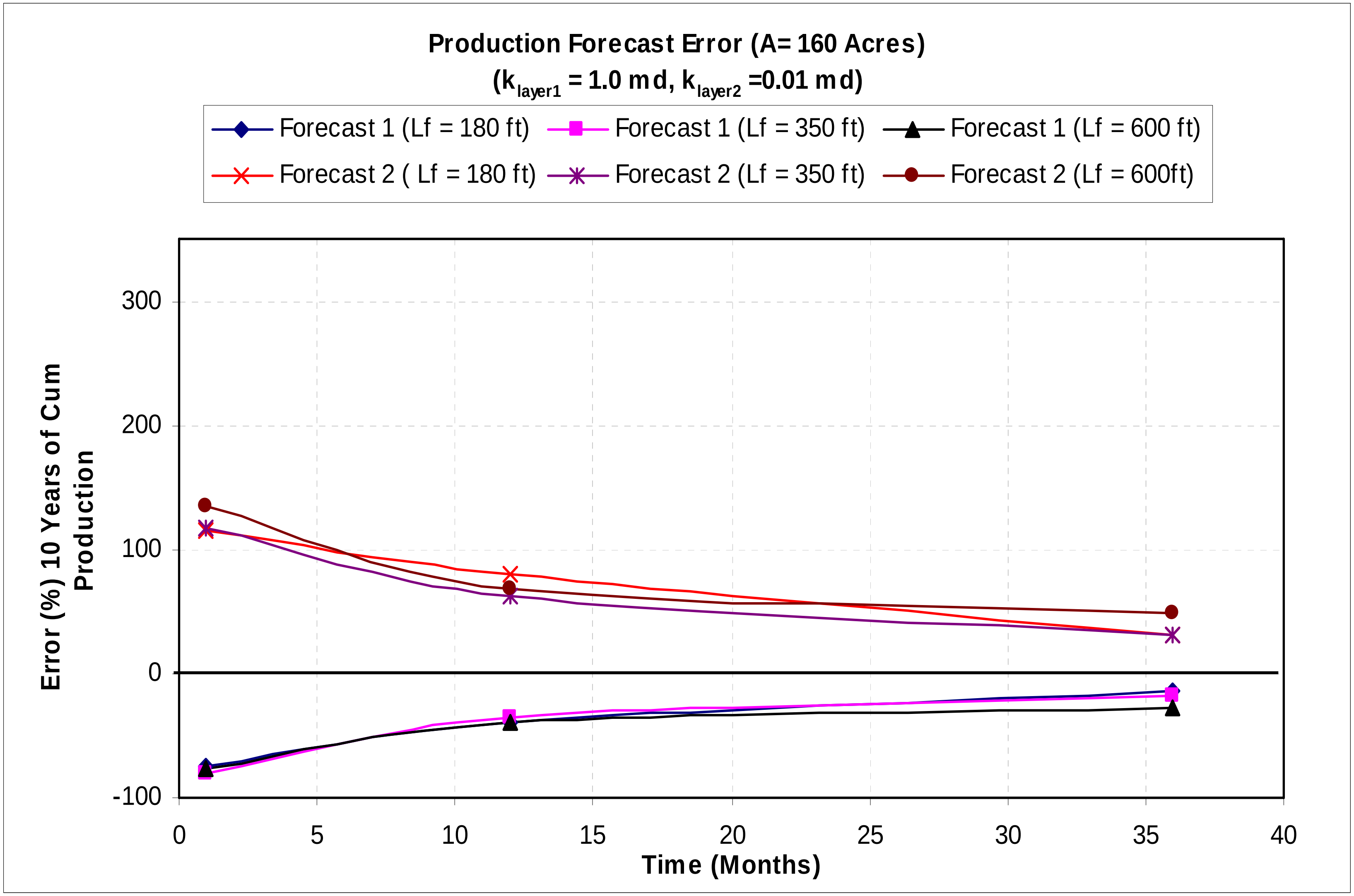

Fig 5.2 *Production Forecast Error Scenario One (A=160 acres, k_{layer1}= 1.0 md, K_{layer2}=0.01 md)*

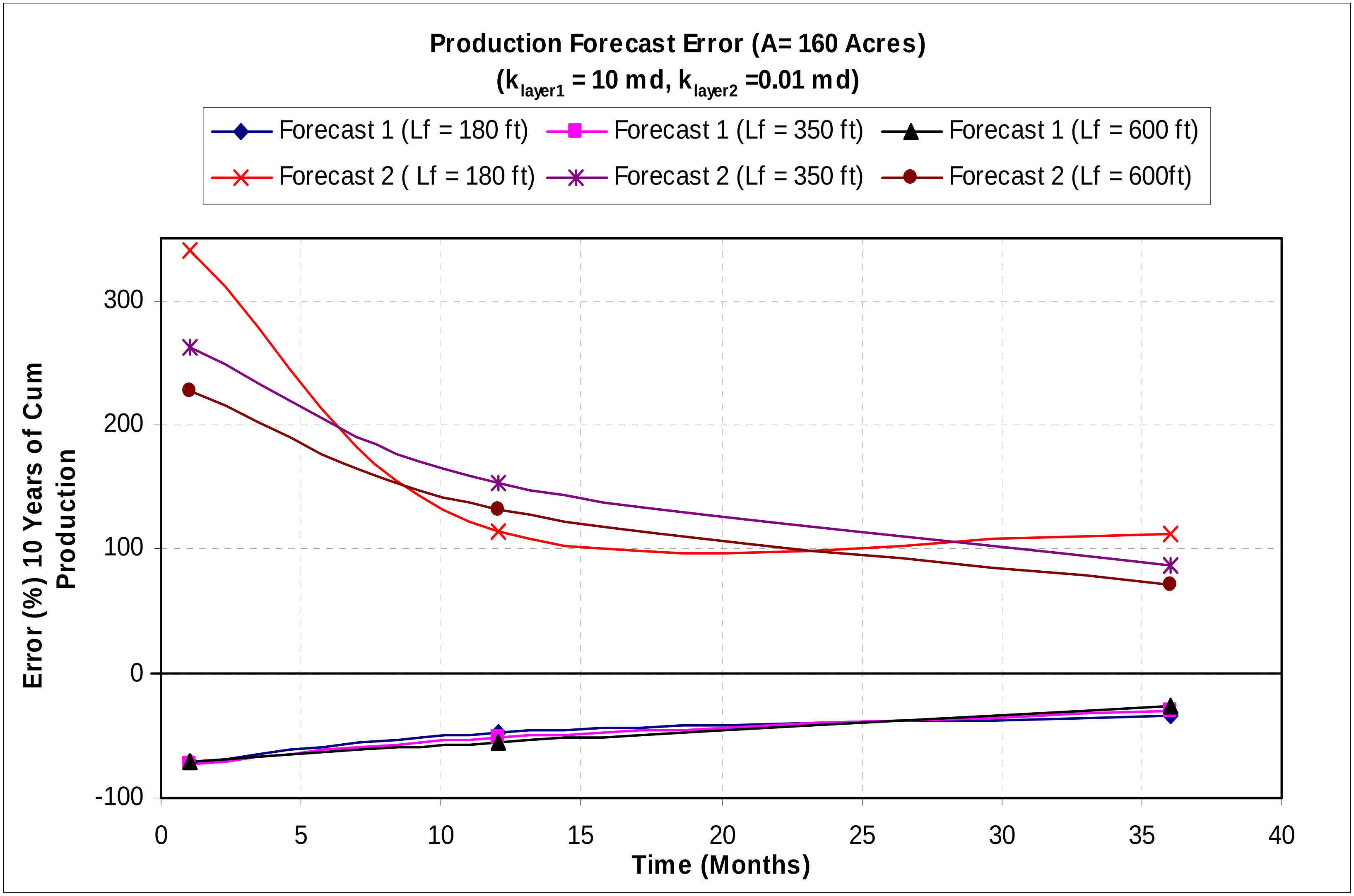

Fig 5.3 *Production Forecast Error Scenario One (A=160 acres, k_{layer1}= 10 md, K_{layer2}=0.01 md)*

Fig. 5.3 shows the error in ten-year gas production forecasts for the Scenario one reservoir model with a large permeability contrast, varying up to three orders of magnitude, ($k_{layer\ 1}$= 10md and $k_{layer\ 2}$ = 0.01md) and a drainage area of 160 acres. The forecasts did not yield good estimates of 10 years cumulative gas production even if three years of production is history match. Again, Forecast (1) results did not yield reliable ten years of gas production because of the small drainage area values obtained by the matches. Forecast (2) results did not yield reliable ten years of gas production because of the large values of average permeability calculated by the matches when a single-layer model was used.

5.2 Discussion of Simulation Case Results for Scenario Two

Table 5.2 summarizes the history match results for the case Nos 91-99 from Table A-2. Tables of history match results for the remaining simulation cases for scenario two examples can be found in APPENDIX B (Tables B.9-B.13). Table 5.2 shows the values for permeability; fracture half-length and drainage area estimated by the history match analyses with their respective error for case Nos 91-99.

The large variation in the permeability of typical layered tight gas reservoirs will affect dramatically the results of reservoir properties estimated when using single-layer models to analyze production data. As the layer permeability contrasts increases, the permeability-thickness product calculated using a single layer model will increase, especially if limited production data are analyzed. For instance, in Table 5.2, case Nos 97-99, where only one month of production data were analyzed, as the permeability in the high permeability layer increased from 0.1 to 1.0 to 10 md, the permeability-thickness product increased from 3.69 to 10.6 to 28.85 md-ft, respectively. However the high permeability layers do not contain the bulk of the gas in place.

In case No 91, one can see that the equivalent single-layer permeability obtained from the history match (0.00622 md) is even smaller than the permeability of the low permeability layer (0.01 md) when a long period of production data is matched. This phenomenon is due to the fact that in three years, the high permeability layer which has a limited areal extend has depleted completely; therefore, the permeability-thickness product calculation starts being controlled principally by the permeability value of the low permeability layer which covers only 90% of the total thickness. Thus, when the permeability from 90% of the net pay is distributed evenly over 100% of the pay, the average value of permeability will be even less than the value over the 90% zone.

In Table 5.2 can be seen that the drainage area will always be underestimated if the data collected are still in the transient flow period in the layers that contain the bulk of the gas in place. For instance, the drainage area calculated by the history match for cases No 91, No 94, and No 97 decreased from 53 to 26 to 6 acres, respectively, as the amount of production data used in the history match decreased from three years to one year to one month, respectively. In the cases where production data from three years as well as one year were analyzed, the contrast in permeability within the layers affected the estimation of drainage area for the reservoir system. As the permeability contrast increased within the layers, the computed value of drainage area decreased. For instance, in Table 5.2, one can notice that drainage area of the well in cases No 91, No 92 and, No

93, where three years of production data was used in the analysis, decreased from 53 to 25 to 22 acres, respectively, as the permeability in the high permeability layer is increased. However, when only one month of production data were analyzed, the drainage area estimate kept constant as the permeability contrast increased as shown in cases No 97, No 98 and, No 99 where the drainage areas were estimated to be 6, 7 and 6 acres, respectively.

One can also observe, In Table 5.2, that when one tries to history match more than twelve months of production data from a reservoir with moderate (permeability varying two orders of magnitude) to high permeability contrasts (permeability varying three orders or magnitude) where the high permeability interval has a smaller drainage area, a perfect match cannot be achievable unless the geometry of drainage area is varied, as shown in cases No 92, No 93, No 95, and No 96. Petroleum engineers often vary the geometry of the drainage area to obtain “perfect matches” of production data claiming that there might be a nearby natural boundary or a boundary caused by an offset well. However, the results of reservoir properties for these perfect history matches are most of the time incorrect.

Table 5.2 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 91-99*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	40	1.0	10	40	10	10	40
Bottom Layer:	0.01	90	160	0.01	90	160	0.01	90	160
Three Years of Production Data									
		Case 91			**Case 92**			**Case 93**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	0.622	-67.26	10.9	**1.32**	-87.89	100.9	**1.15**	-98.86
Lf, (ft)	350	643	83.71	350	**472**	34.86	350	**459**	31.14
A, (acres)	160	53	-66.88	160	**25**	-84.38	160	**22**	-86.25
Forecast 1, (Bcf)	2.67	2.48	-7.12	2.68	**1.97**	-26.49	2.68	**1.86**	-30.60
Forecast 2, (Bcf)	2.67	2.85	6.74	2.68	**3.8**	41.79	2.68	**4.05**	51.12
One Year of Production Data									
		Case 94			**Case 95**			**Case 96**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	1.23	-35.26	10.9	**2.56**	-76.51	100.9	**3.56**	-96.47
Lf, (ft)	350	389	11.14	350	**360**	2.86	350	**336**	-4.00
A, (acres)	160	26	-83.75	160	**14**	-91.25	160	**13**	-91.88
Forecast 1, (Bcf)	2.67	1.96	-26.59	2.68	**1.34**	-50.00	2.68	**1.102**	-58.88
Forecast 2, (Bcf)	2.67	3.28	22.85	2.68	**5.11**	90.67	2.68	**6.18**	130.60
One Month of Production Data									
		Case 97			**Case 98**			**Case 99**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	3.694	94.42	10.9	10.6	-2.75	100.9	28.85	-71.41
Lf, (ft)	350	164	-53.14	350	120	-65.71	350	111	-68.29
A, (acres)	160	6	-96.25	160	7	-95.63	160	6	-96.25
Forecast 1, (Bcf)	2.67	0.54	-79.78	2.68	0.6	-77.61	2.68	0.5	-81.34
Forecast 2, (Bcf)	2.67	4.9	83.52	2.68	8.48	216.42	2.68	12.2	355.22

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

The fracture half-length estimates for all the cases in Scenario two also presented a very high variability. However, unlike Scenario one where there was not a definite trend in the results, it was found that in Scenario two, the values of fracture half-length estimates decreased as the amount of data used in the analysis decreased. For example, in case No 91 where three years of production data were analyzed, the fracture half-length was calculated to be 643 ft; on the other hand, in case No 94 and No 97 where one year and one month were analyzed, correspondingly, the fracture half-length estimates were calculated to be 389 and 164 ft, respectively. The reason is that because in three years the average permeability for the single-layer model is calculated so small, the fracture half-length estimate has to be large in order to match the high rate decline created by the high permeability layer. On the other hand, when a short period of production data such as a month is analyzed, the average permeability for the single-layer model is calculated to be so large since the flow rate is still dominated by the high permeability layer; therefore, the fracture half-length estimate has to be small to compensate and match the production data.

Figs 5.4-5.6 show the error for ten years of gas production forecasted using the history match results vs. the amount of production data used in the history match analysis for scenario two. Fig. 5.4 shows the error for the reservoir model with a small permeability contrast ($k_{layer\ 1}$= 0.1md and $k_{layer\ 2}$ = 0.01md) and a drainage area of 160 acres and 40 acres for the bottom and top layers, respectively. Each line represents the error of either Forecast (1) or Forecast (2) for three different fracture half-lengths. As can be seen in Fig. 5.4, all Forecast (1) results underestimate the actual cumulative production while all forecast (2) results overestimate the actual cumulative production. One can see in Fig. 5.4 that to obtain fair estimates of ten years of gas production, about three years of production data need to history match.

Fig. 5.5 shows the error of ten years of gas production forecasted for the reservoir model with a medium permeability contrast ($k_{layer\ 1}$= 1.0md and $k_{layer\ 2}$ = 0.01md) and a drainage area of 160 acres and 40 acres for bottom and top layers, respectively. As shown in Fig. 5.5, the forecasts will not yield good estimates of 10 years of cumulative production even if three years of production is history match do to either the small drainage area estimated by the match in Forecast (1) results or large average single-layer model permeability estimated by the match in Forecast (2) results.

Fig. 5.6 shows the error of Ten years of gas production forecasted for the reservoir model with a high permeability contrast ($k_{layer\ 1}$= 10md and $k_{layer\ 2}$ = 0.01md) and a drainage area of 160 acres and 40 acres for bottom and top layers, respectively. As shown in Fig. 5.6, the forecasts will yield estimates of 10 years of cumulative production with an error of about 35% for Forecast (1) cases and 60% for Forecast (2) cases if three years of production data are history matched.

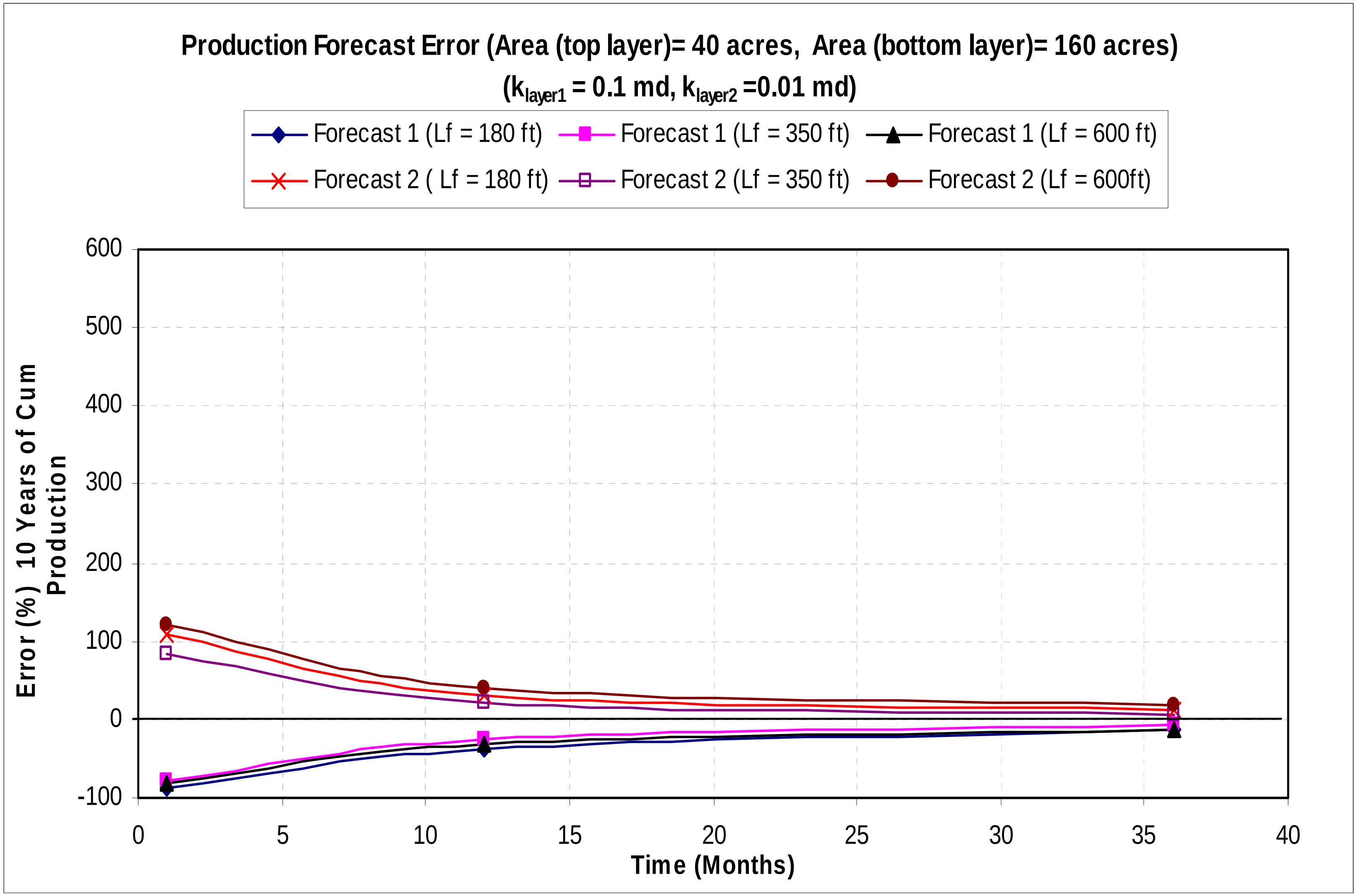

Fig 5.4 *Production Forecast Error Scenario Two (A_{layer1}=40 acres, A_{layer2}=160 acres, k_{layer1}= 0.1md, k_{layer2}=0.01 md)*

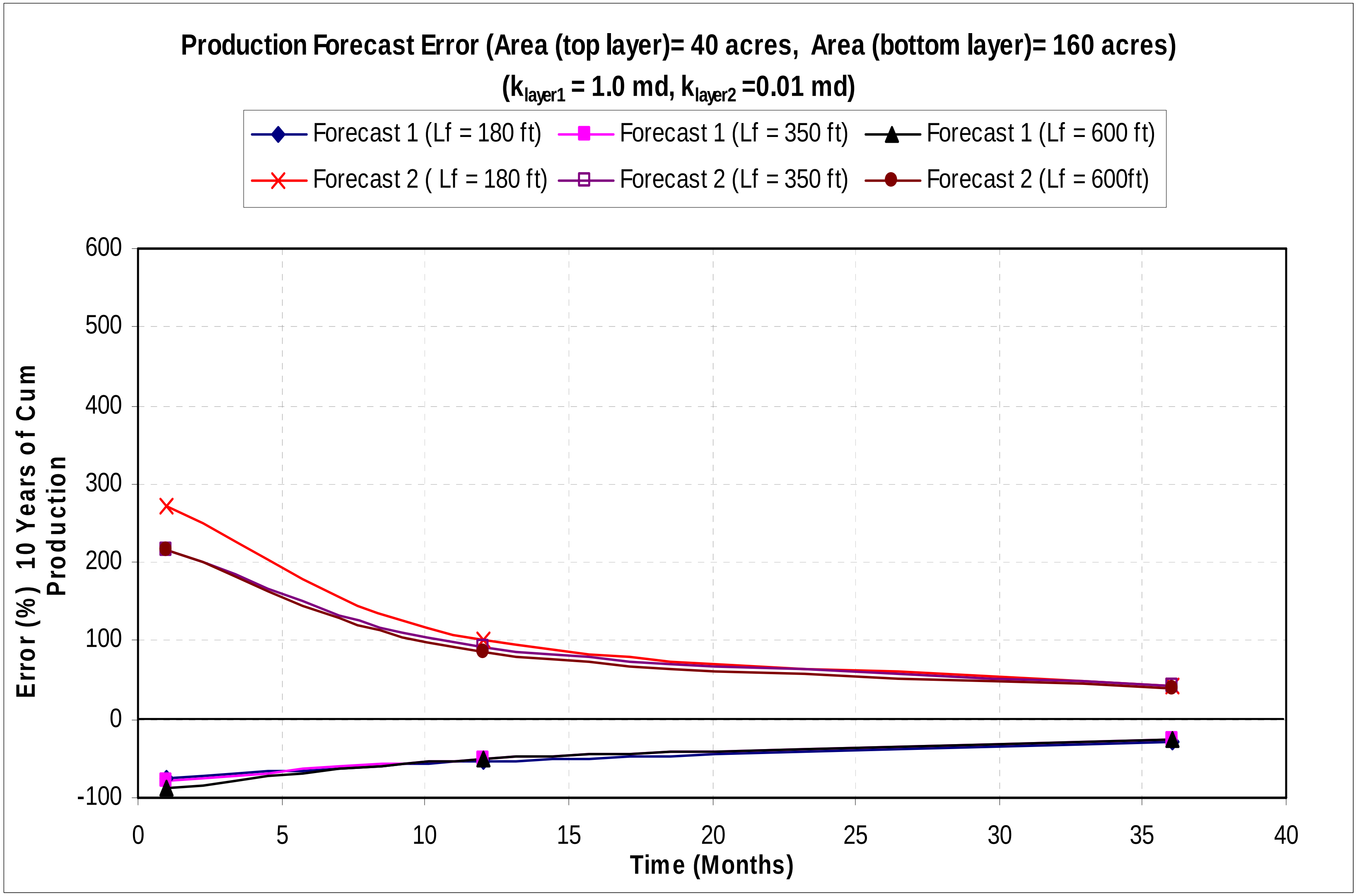

***Fig 5.5** Production Forecast Error Scenario Two (A_{layer1}=40 acres, A_{layer2}=160 acres, k_{layer1}= 1.0md, k_{layer2}=0.01 md)*

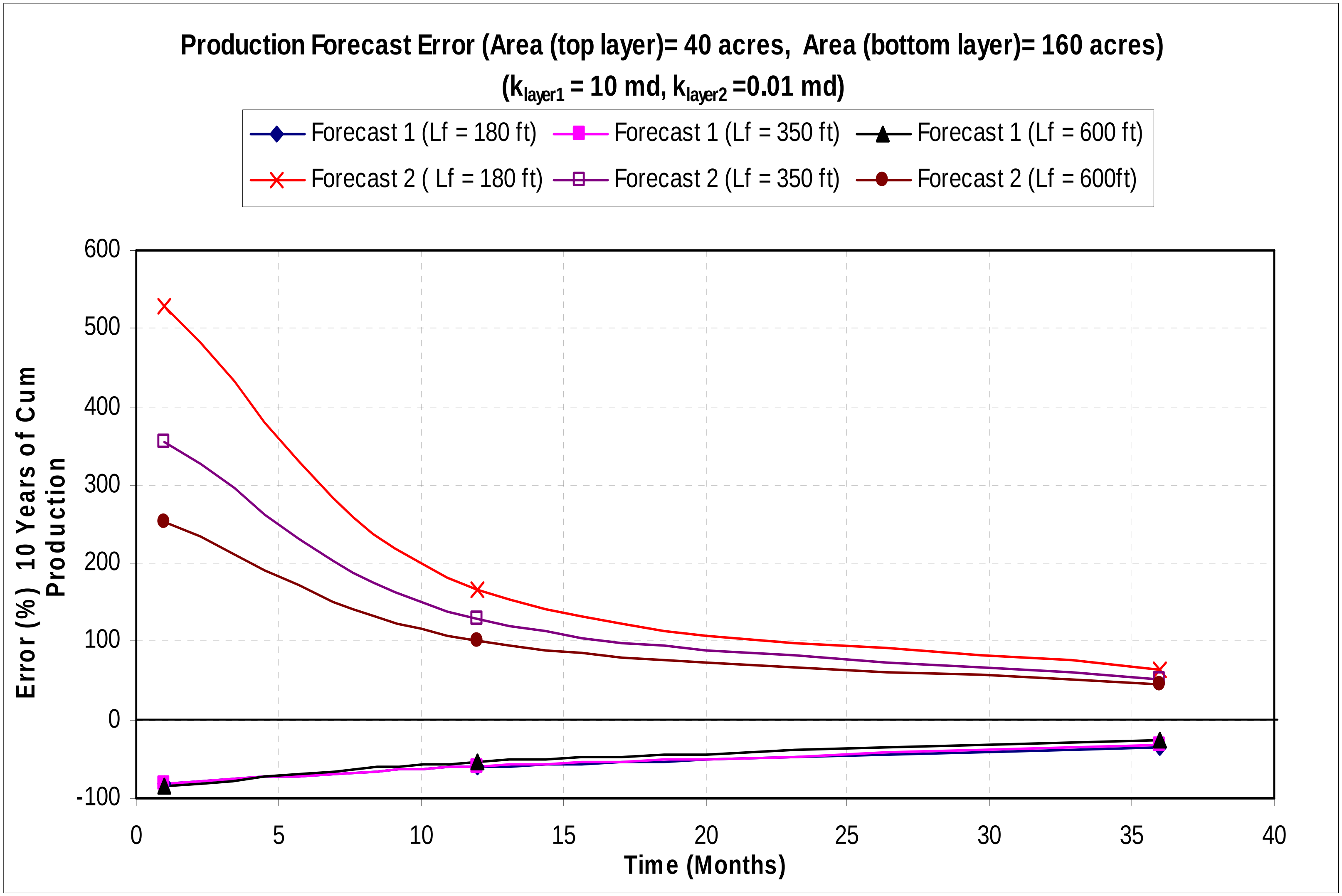

Fig 5.6 *Production Forecast Error Scenario Two (A_{layer1}=40 acres, A_{layer2}=160 acres, k_{layer1}= 10md, k_{layer2}=0.01 md)*

5.3 Discussion of Simulation Case Results for Scenario Three

Table 5.3 summarizes the history match results for case Nos 142-144 from Table A-3. Table 5.3 presents values for permeability-thickness, fracture half-length and drainage area with their respective error. Table 5.3 also shows the error of ten years of gas production for the reservoir model when forecasted with the values calculated from the history match analysis. Tables of history match results for the remaining simulation cases for case scenario three can be found in APPENDIX B (Tables B.14-B.18)

In Table 5.3, one can see that the equivalent single-layer permeability calculated by the match in cases such as Case No 142 (0.0089 md) and No 143 (0.00926 md) where three years and one year of production data were analyzed, respectively. Notice that these values are lower than the low permeability layer (0.001 md). For these cases, the high permeability layer (10 md) and the medium permeability layer (1.0 md) has mostly depleted during the first year; therefore, the permeability-thickness product is dominated during the last two years by the permeability value of the low permeability layer which only cover 85% of the total thickness. Thus, when the permeability from 85% of the net pay is distributed evenly over 100% of the pay, the average value of permeability will be even less than the value over the 85% zone. On the other hand, when one month of production data were analyzed, a single-layer model permeability (0.9683 md) of about two orders of magnitude larger than the low permeability layer was estimated.

For scenario three, when one tries to history match three years of production data, as shown in case No 142, the drainage area of the well is overestimated; therefore, a constrain of a maximum drainage area of 160 acres had to be set for these cases. The reason of the overestimation in the drainage area in case No 142 is because of the low single-layer model permeability estimated by the match, the calculation has to compensate for the rapid decline rate and the large volume of hydrocarbon produced during the early time by finding a large average of drainage area. In case No 144, when one month of production data were analyzed, , the average drainage area (4 acres vs. 160 acres) was underestimated by 97% because the pressure transient only reached a small fraction of the total drainage area.

For scenario three, history matching three years of production data gave reliable results of 10 year of cumulative forecast, falling within ±10%; however, none of these cases showed accurate estimates of reservoir properties used in the simulations. These reliable forecasts are due to the fact that three years of production data already present a definite trend and the main function of history matching is to find the best combination of parameters that minimizes the vertical deviation or error, and since the drainage area calculated is large, the gas volume to be produced is larger.

Table 5.3 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 142-144*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	160
Middle Layer:	10	5	20
Bottom Layer:	0.01	85	160
Three Years of Production Data			
		Case 142	
Units	Input Values	Calculated Values	error (%)
kh, (md-ft)	51.85	0.893	-98.28
Lf, (ft)	350	593	69.43
A, (acres)	160	160	0.00
Forecast 1, (Bcf)	3.27	3.38	3.36
One Year of Production Data			
		Case 143	
Units	Input Values	Calculated Values	error (%)
kh, (md-ft)	51.85	0.926	-98.21
Lf, (ft)	350	501	43.14
A, (acres)	160	75	-53.13
Forecast 1, (Bcf)	3.27	2.83	-13.46
One Month of Production Data			
		Case 144	
Units	Input Values	Calculated Values	error (%)
kh, (md-ft)	51.85	9.683	-81.32
Lf, (ft)	350	189	-46.00
A, (acres)	160	4	-97.50
Forecast 1, (Bcf)	3.27	0.35	-89.30

Forecast 1: Using History Matched Area
Forecast 2: Using 160 Acres

Calculated Values = Light Match with square Area
Bold Match with rectangular area

Fig. 5.7 shows the error for ten years of gas production forecasted using the history match results vs. the amount of production data used in the history match analysis for case scenario three.

Fig. 5.7 displays the error of the ten years of production forecast for the reservoir model with three layers with permeabilities that vary from 0.01 md to 10 md (k_{Top}= 1.0, k_{middle}= 10md, and k_{bottom}= 0.01md) and a drainage area of 160 acres for the top and bottom layers and 20 acres for the middle high permeability layer. All forecast (1) results underestimate the actual cumulative production If one history matches only one month of production data and uses the all the results, including the calculated drainage area, to forecast cum production for 10 years, one will underestimate the forecast by up to 90%. Reliable forecasts under 10% error will be achieved for these cases when 3 years of production data is available for the history match evaluation; however, the properties estimated by the analysis will not describe the real properties of the reservoir.

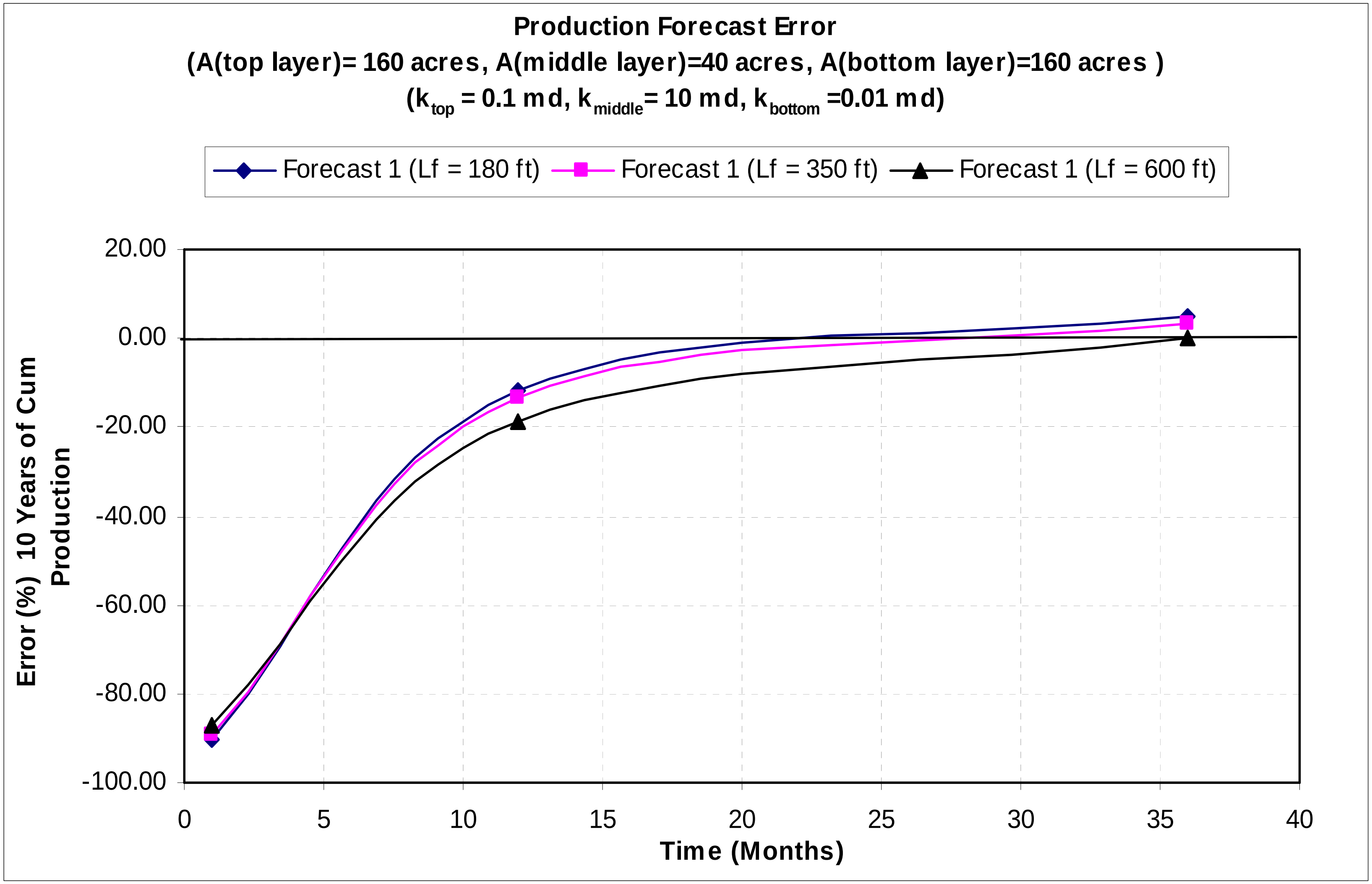

Fig 5.7 *Production Forecast Error Scenario Three ($A_{top\ layer}$=160 acres, $A_{middle\ layer}$ =40acres, $A_{bottom\ layer}$=160acres k_{top}= 0.1md, k_{middle}=0.01 md k_{bottom}=0.01 md)*

5.4 Discussion of Results for Multi-layer Production History Analysis

Because most of the tight gas sands in the United States, including those of the Cotton Valley formation in East Texas and North Louisiana, produce from multiple intervals being independent from each other with their gas production commingled by the hydraulic fracture and the wellbore, conventional, single-layer modeling techniques will only estimate effective properties of an equivalent single-layer reservoir that will usually result in erroneous values as the permeability contrasts within the layers increase. Spivey[39] developed a single-well analytical simulator for multi-layer unconventional gas reservoirs to try to overcome the challenges involved when analyzing the performance of these complex reservoirs. Spivey's multi-layer simulator was used in this study to prove its efficacy.

Three cases (case No 11, 92, and 142), one from each scenario, were analyzed using Spivey's model with a multi-layer description. Table 5.4 summarizes the history match results for the three cases along with their respective error. In Table 5.4, one can see that the permeability-thickness (*kh*) product for each case was in agreement with the true permeability-thickness product used in the simulation falling within an error of less than 10%. Case No 11 had a permeability-thickness product estimate of 5.74 md-ft with an error of 3.5% with respect to the true permeability-thickness product (5.95 md-ft). Case No 92 and 142 had more error; however, they were still under 10% error. For Case No 92, the computed kh was 9.974 md-ft and the actual was 10.9 md-ft (8.5% error). For case No 142 the computed value was 46.318 md-ft which the input value was 50.85 (9% error).

Table 5.4 *Percentage Error in Calculated Values from History Match Analysis Using a Multi-layer Description Model, Simulation Cases 11, 92, 142*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	1.0	5	160	1.0	10	40	1.0	10	160
Middle Layer		Two-Layer Case			Two-Layer Case		10	5	40
Bottom Layer:	0.01	95	160	0.01	90	160	0.01	85	160
Three Years of Production Data									
								Case 142	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	5.95	5.74	-3.53	10.9	9.974	-8.50	50.85	46.318	-8.91
Lf, (ft)	350	347	-0.86	350	342	-2.29	350	341	-2.57
$A_{Top\ Layer}$, (acres)	160	164	2.50	40	40	0.00	160	161	0.63
$A_{Middle\ Layer}$, (acres)		Two-Layer Case			Two-Layer Case		20	21	5.00
$A_{Bottom\ Layer}$, (acres)	160	48	-70.00	160	84	-47.50	160	94	-41.25
M-L Forecast (1), (Bcf)	3.2	2.82	-11.88	2.68	2.6	-2.99	3.27	3.15	-3.67
M-L Forecast (2), (Bcf)	3.2	3.14	-1.88	2.68	2.68	0.00	3.27	3.24	-0.92

Forecast 1:	Using History Matched Area	Calculated Values=	Light	Match with square area
Forecast 2:	Using 160 acres		**Bold**	Match with rectangular area

The average fracture half-length estimates for case No 11, 92, and 142 were also close to the true values for every case, as shown in Table 5.4. For case No 11, 92, and 142, the average fracture half-length computed were 347, 342, and 341 ft, respectively, compared to 350 ft used in the simulation

The drainage areas for the layers that had a extremely small permeability value, in all the cases analyzed, were underestimated because in three years of production they had not reached boundary-dominated flow. For instance, the drainage area of the bottom layer in case No 11 was underestimated by 70% (48 acres, vs. 160 acres). In case No 92 the drainage area for the bottom layer (k = 0.01 md) was computed to be 84 acres and the actual value was 160 acres with an underestimation error of -47.50%. Likewise, in case No 142, the drainage area of the bottom layer (k = 0.01 md) was estimated to be 94 acres having an underestimation error of -41%. On the other hand, the layers with larger permeability values that reached boundary-dominated flow within three years achieved well-estimated of drainage areas.

Although the drainage areas of the layers with small permeability values in all the cases which contain the majority of gas in place were underestimated, the history matches gave reliable estimates of ten years of production forecast. In ten years, the three cases explained will only deplete a small fraction of the total-gas in-place and the drainage area that were estimated by the history matches was large enough to produce that fraction of total-gas-in placed produced in those 10 years.

Comparing the permeability-thickness products (*kh*) for the three cases analyzed with the multi-layer model to the permeability-thickness products for the same cases analyzed with the single-layer model, it seems that when three years of production data are analyzed using a single-layer model analysis, the permeability-thickness product presents a larger underestimation value than the permeability-thickness product obtained by the multi-layer model analysis. If the value of kh obtained by the single-layer model is used with the real drainage area of the reservoir to forecast ten years of gas production, the resulting forecast will be overestimated by a large amount. On the other hand, if one was to use the kh value obtained by the multi-layer model analysis to forecast ten years of gas production, the resulting forecast will be reliable forecast falling within a 10% error. For instance, in case No 92 the kh obtained by the single-layer model was underestimated by 88% (1.32 md-ft vs. 10.9 md-ft); however, the forecast was overestimated by 42% (3.8 Bcf vs. 2.68 Bcf). On the other hand, the kh obtained by the multi-layer model was only underestimated by 8.5% (9.974 md-ft vs. 10.9 md-ft) and the forecast was only underestimated by 3% (2.6 Bcf vs. 2.68 Bcf). One might think that because of the low kh value obtained by the single-layer model, the ten years of gas production forecast would be underestimated; however, this is not the case because the average permeability (*k*) value when distributed evenly over the total thickness of the reservoir, will be larger than the actual permeability of the low permeability layer where the bulk of gas in place is located; thus overestimating the ten years of gas production forecast. On the contrary, the permeability obtained by the multi-layer model is distributed accordingly with the magnitude of permeability in each layer over the entire thickness since every layer is taken as an individual single-layer model.

PMTx proved effective when calculating reservoir parameters in multi-layer tight gas reservoirs as long as one has data from multiple production logs. The simulator history matches production data and production log data simultaneously to allocate flow rate within the layers. Therefore, production logs are required at different times in the well's life. However, in the oil field production logs are not often run because of their expensive costs. The simulator models every layer as a separate single-layer reservoir to calculate reservoir properties in each layer individually, a large number of parameters have to be varied; therefore, only three parameters in each layer can be varied at a time. Also, the parameters to be varied have to be manually adjusted close to a solution before beginning the automatic matching process. As the number of layers increases, the more accurate the starting guesses have to be to reach a satisfactory solution; therefore, it is essential that the reservoir engineer has a very clear understanding of the reservoir before beginning to perform the history match analysis.

CHAPTER VI

SUMMARY AND CONCLUSIONS

6.1 Summary

Single-layer models are often used by reservoir engineers to analyze production data and forecast gas production in tight gas reservoir systems. However, most of the tight gas systems that reservoir engineers have to deal with are layered systems where the permeability and porosity of each layer can vary considerably. In addition, the drainage areas of each of the layers can be substantially different. Analyzing production data for tight gas sands using single-layer techniques rarely provide the engineer with the accuracy required to forecast gas production. Single-layer models do not take into account the complexity of typical multi-layer tight gas reservoirs. Thus, when the single layer model is forced to “match” data from multi-layer systems, the match will not usually allow one to accurately forecast future gas production. To find a better history match, one that really describes the reservoir being analyzed, one should use multi-layer models in multi-layer reservoirs. However, to properly use a multi-layer model, one has to characterize the layers and sum production logs to obtain flow rates from the layers as a function of time.

In this research, production data for a vertical well containing a vertical hydraulic fracture and producing from a typical layered tight gas reservoir, resembling the rock and fluid properties often observed in the Cotton Valley formation in East Texas or North Louisiana, were generated by using Eclipse, which is a finite-difference black oil reservoir simulator. The production data generated were then analyzed by using single-layer models to investigate typical errors that can occur when one analyzes production data using simple single-layer techniques to obtain reservoir properties and use those values to forecast ultimate recovery in such complex reservoirs. The generated production data were also analyzed by a new single-well analytical simulator (PMTx) for multi-layer unconventional gas reservoirs to prove its effectiveness when dealing with such challenging reservoirs.

6.2 Conclusions

On the basis of the work done during this research project, the following conclusions are offered:

1. The accuracy in reservoir properties and future gas flow rates results in layered tight gas reservoirs when analyzed using a single-layer model is a function of the degree of variability in permeability within the layers and the availability of production data to be analyzed.
2. As the amount of production data used to analyze a well increases, the match and forecast of future gas flow rates become more accurate.
3. In the case of a layered tight gas reservoir where there is a variability in “k” of two orders of magnitude and up and only up to a year worth of production data, using a single-layer model will estimate and equivalent single-layer permeability that is greater (up to three orders of magnitude) than the low permeability layer where the bulk of gas in place is located. As a result, the gas

recovery forecast will be either overestimated if the forecast is generated by using the reservoir property estimates from the history match plus the real drainage area of the reservoir or underestimated if the forecast is generated using all the reservoir properties obtained by the history match analysis.

4. The production data in cases where the tight gas reservoir presented a range of three orders of magnitude in “k” within the layers could be matched better in appearance by changing the geometry of the drainage area; however, the results of reservoir properties estimated were erroneous as well as the shape of the reservoir.
5. In the cases where the permeability in the layers varied only up to one order of magnitude, reliable Ten-year gas production forecasts falling in the 10% error or less could be obtained after analyzing 15 months worth of data. On the other hand, if the permeability in the layers varied three orders of magnitude, the forecast would be overestimated by up to 90% or underestimated by up to 45% depending on the drainage area used to generate the forecasts.
6. In the case where there is an idea that the reservoir presents a large variability in ‘’k”, using a multi-layer model to analyze the production data will provide the reservoir engineer with more accurate estimates of long-term production recovery and reservoir properties. However, when using a multi-layer model to obtain a successful solution in analyzing tight gas reservoirs it is essential that the engineer has a clear understanding of the reservoir to be able to describe it as feasible as possible.

6.3 Recommendations

On the basis of this work, the following recommendations are offered:

1. If over one year of production data is available and the only resource to analyze the data is a single-layer model, it is recommended that the data be analyze month by month to check the change in the estimation of permeability. If the change is large from month to month, it is an indicative that the reservoir is indeed a multilayer reservoir with a large variability in permeability in the layers.
2. To analyze production data from layered tight gas reservoirs with large variability in permeability within the layers, it is recommended that multi-layer model methods be used for the analysis to obtain more accurate results of reservoir properties and production recovery.
3. Before starting the production history matching analysis, it is recommended that the reservoir engineer have a detailed description of the reservoir to set up a layered model that best describes the reservoir.
4. In the effort to obtain a detail reservoir description, the reservoir engineer can integrate different well tests such build-up tests and deliverability tests, with core measurements and logs to clearly identify net pay thickness, porosity, saturations and the ranges of permeabilities from individual layers. Also, use geologic reservoir description information and experience to estimate the areal extent of each layer.

5. Production logs at different points in time, especially early in the life of the well, are also needed for the multi-layer model methods to allocate the total flow rate within the layers.

NOMENCLATURE

b	=	production decline exponent
B_g	=	gas formation volume factor, RB/Mscf
B_{gi}	=	gas formation volume factor at initial conditions, RB/Mscf
B_w	=	water formation volume factor, RB/STB
CAL_N	=	caliper, in
c_g	=	gas compressibility, psia^{-1}
c_t	=	total compressibility, psia^{-1}
D_i	=	initial decline rate, day^{-1}
G	=	original gas in place, Mscf
G_p	=	cumulative gas production, Mscf
GR_N	=	normalized gamma ray, API
h	=	net formation thickness, ft
k	=	formation permeability, md
L_f	=	fracture half-length, ft
$m(\bar{P})$	=	real gas pseudo-pressure, psi^2/cp
n	=	exponent in back pressure equation
NPHI_N	=	neutron porosity, porosity units
$\bar{P}$	=	average reservoir pressure, psia
PERM	=	permeability, md
P_i	=	initial reservoir pressure, psia

POR_N	=	porosity, fraction
P_{wf}	=	bottom flowing pressure, psia
q_D	=	dimensionless flow rate
q_g	=	gas flow rate, Mscf/D
q_{gi}	=	initial gas flow rate, Mscf/D
R	=	radius ratio r_e / r_w
r_e	=	outer radius of reservoir, ft
RHOB_N	=	density log, gm/cc
RTD_N	=	resistivity, ohm-meter
r_w	=	wellbore radius, ft
SP_N	=	normalized spontaneous potential, MV
SWT	=	water saturation, fraction
t	=	time, days
t_a	=	pseudo-equivalent time, hours
t_D	=	dimensionless time for Carter type curve
t_n	=	normalized time, hours
t_s	=	stabilization time, hours
V_f	=	reservoir formation (rock) volume, res bbl
V_w	=	volume of water, res bbl
W_e	=	cumulative water influx volume, res bbl
w_f	=	fracture width, ft
$w_f\, k_f$	=	fracture conductivity, md-ft

W_p = cumulative water production, STB

z = gas compressibility factor

z_i = gas compressibility factor at initial conditions

Subscripts

f = fracture

g = gas

i = initial

p = cumulative

w = water

wf = flowing-wellbore

Greek Symbols

Δ = differential

μ = viscosity, cp

ϕ = porosity, percentage

η = transient-flow-period correlation parameter

λ = boundary-dominated-flow-period correlation parameter

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APPENDIX A

TABLES OF SIMULATION RUNS FOR CASE SCENARIOS

Table A.1 *Set of Simulations for Case Scenario One*

Case	Layers	Permeability k md	Area A Acres	Fracture Half-Length L_f ft	Production Time t Months
1	Top Bottom	0.1 0.01	160	180	36
2	Top Bottom	1 0.01	160	180	36
3	Top Bottom	10 0.01	160	180	36
4	Top Bottom	0.1 0.01	160	180	12
5	Top Bottom	1 0.01	160	180	12
6	Top Bottom	10 0.01	160	180	12
7	Top Bottom	0.1 0.01	160	180	1
8	Top Bottom	1 0.01	160	180	1
9	Top Bottom	10 0.01	160	180	1
10	Top Bottom	0.1 0.01	160	350	36
11	Top Bottom	1 0.01	160	350	36
12	Top Bottom	10 0.01	160	350	36
13	Top Bottom	0.1 0.01	160	350	12
14	Top Bottom	1 0.01	160	350	12
15	Top Bottom	10 0.01	160	350	12
16	Top Bottom	0.1 0.01	160	350	1
17	Top Bottom	1 0.01	160	350	1
18	Top Bottom	10 0.01	160	350	1
19	Top Bottom	0.1 0.01	160	600	36
20	Top Bottom	1 0.01	160	600	36
21	Top Bottom	10 0.01	160	600	36
22	Top Bottom	0.1 0.01	160	600	12
23	Top Bottom	1 0.01	160	600	12
24	Top Bottom	10 0.01	160	600	12
25	Top Bottom	0.1 0.01	160	600	1
26	Top Bottom	1 0.01	160	600	1
27	Top Bottom	10 0.01	160	600	1

Table A.1 *Continued*

Case	Layers	Permeability *k* md	Area *A* Acres	Fracture Half-Length L_f ft	Production Time *t* Months
28	Top Bottom	0.1 0.01	80	180	36
29	Top Bottom	1 0.01	80	180	36
30	Top Bottom	10 0.01	80	180	36
31	Top Bottom	0.1 0.01	80	180	12
32	Top Bottom	1 0.01	80	180	12
33	Top Bottom	10 0.01	80	180	12
34	Top Bottom	0.1 0.01	80	180	1
35	Top Bottom	1 0.01	80	180	1
36	Top Bottom	10 0.01	80	180	1
37	Top Bottom	0.1 0.01	80	350	36
38	Top Bottom	1 0.01	80	350	36
39	Top Bottom	10 0.01	80	350	36
40	Top Bottom	0.1 0.01	80	350	12
41	Top Bottom	1 0.01	80	350	12
42	Top Bottom	10 0.01	80	350	12
43	Top Bottom	0.1 0.01	80	350	1
44	Top Bottom	1 0.01	80	350	1
45	Top Bottom	10 0.01	80	350	1
46	Top Bottom	0.1 0.01	80	600	36
47	Top Bottom	1 0.01	80	600	36
48	Top Bottom	10 0.01	80	600	36
49	Top Bottom	0.1 0.01	80	600	12
50	Top Bottom	1 0.01	80	600	12
51	Top Bottom	10 0.01	80	600	12
52	Top Bottom	0.1 0.01	80	600	1
53	Top Bottom	1 0.01	80	600	1
54	Top Bottom	10 0.01	80	600	1

***Table A.1** Continued*

Case	Layers	Permeability k md	Area A Acres	Fracture Half-Length L_f ft	Production Time t Months
55	Top Bottom	0.1 0.01	40	180	36
56	Top Bottom	1 0.01	40	180	36
57	Top Bottom	10 0.01	40	180	36
58	Top Bottom	0.1 0.01	40	180	12
59	Top Bottom	1 0.01	40	180	12
60	Top Bottom	10 0.01	40	180	12
61	Top Bottom	0.1 0.01	40	180	1
62	Top Bottom	1 0.01	40	180	1
63	Top Bottom	10 0.01	40	180	1
64	Top Bottom	0.1 0.01	40	350	36
65	Top Bottom	1 0.01	40	350	36
66	Top Bottom	10 0.01	40	350	36
67	Top Bottom	0.1 0.01	40	350	12
68	Top Bottom	1 0.01	40	350	12
69	Top Bottom	10 0.01	40	350	12
70	Top Bottom	0.1 0.01	40	350	1
71	Top Bottom	1 0.01	40	350	1
72	Top Bottom	10 0.01	40	350	1
73	Top Bottom	0.1 0.01	40	600	36
74	Top Bottom	1 0.01	40	600	36
75	Top Bottom	10 0.01	40	600	36
76	Top Bottom	0.1 0.01	40	600	12
77	Top Bottom	1 0.01	40	600	12
78	Top Bottom	10 0.01	40	600	12
79	Top Bottom	0.1 0.01	40	600	1
80	Top Bottom	1 0.01	40	600	1
81	Top Bottom	10 0.01	40	600	1

Table A.2 *Set of Simulations for Case Scenario Two*

Case	Layers	Permeability *k* md	Area *A* Acres	Fracture Half-Length L_f ft	Production Time *t* Months
82	Top Bottom	0.1 0.01	40 160	180	36
83	Top Bottom	1 0.01	40 160	180	36
84	Top Bottom	10 0.01	40 160	180	36
85	Top Bottom	0.1 0.01	40 160	180	12
86	Top Bottom	1 0.01	40 160	180	12
87	Top Bottom	10 0.01	40 160	180	12
88	Top Bottom	0.1 0.01	40 160	180	1
89	Top Bottom	1 0.01	40 160	180	1
90	Top Bottom	10 0.01	40 160	180	1
91	Top Bottom	0.1 0.01	40 160	350	36
92	Top Bottom	1 0.01	40 160	350	36
93	Top Bottom	10 0.01	40 160	350	36
94	Top Bottom	0.1 0.01	40 160	350	12
95	Top Bottom	1 0.01	40 160	350	12
96	Top Bottom	10 0.01	40 160	350	12
97	Top Bottom	0.1 0.01	40 160	350	1
98	Top Bottom	1 0.01	40 160	350	1
99	Top Bottom	10 0.01	40 160	350	1
100	Top Bottom	0.1 0.01	40 160	600	36
101	Top Bottom	1 0.01	40 160	600	36
102	Top Bottom	10 0.01	40 160	600	36
103	Top Bottom	0.1 0.01	40 160	600	12
104	Top Bottom	1 0.01	40 160	600	12
105	Top Bottom	10 0.01	40 160	600	12
106	Top Bottom	0.1 0.01	40 160	600	1
107	Top Bottom	1 0.01	40 160	600	1
108	Top Bottom	10 0.01	40 160	600	1

Table A.2 *Continued*

Case	Layers	Permeability *k* md	Area *A* Acres	Fracture Half-Length L_f ft	Production Time *t* Months
109	Top Bottom	0.1 0.01	20 160	180	36
110	Top Bottom	1 0.01	20 160	180	36
111	Top Bottom	10 0.01	20 160	180	36
112	Top Bottom	0.1 0.01	20 160	180	12
113	Top Bottom	1 0.01	20 160	180	12
114	Top Bottom	10 0.01	20 160	180	12
115	Top Bottom	0.1 0.01	20 160	180	1
116	Top Bottom	1 0.01	20 160	180	1
117	Top Bottom	10 0.01	20 160	180	1
118	Top Bottom	0.1 0.01	20 160	350	36
119	Top Bottom	1 0.01	20 160	350	36
120	Top Bottom	10 0.01	20 160	350	36
121	Top Bottom	0.1 0.01	20 160	350	12
122	Top Bottom	1 0.01	20 160	350	12
123	Top Bottom	10 0.01	20 160	350	12
124	Top Bottom	0.1 0.01	20 160	350	1
125	Top Bottom	1 0.01	20 160	350	1
126	Top Bottom	10 0.01	20 160	350	1
127	Top Bottom	0.1 0.01	20 160	600	36
128	Top Bottom	1 0.01	20 160	600	36
129	Top Bottom	10 0.01	20 160	600	36
130	Top Bottom	0.1 0.01	20 160	600	12
131	Top Bottom	1 0.01	20 160	600	12
132	Top Bottom	10 0.01	20 160	600	12
133	Top Bottom	0.1 0.01	20 160	600	1
134	Top Bottom	1 0.01	20 160	600	1
135	Top Bottom	10 0.01	20 160	600	1

Table A.3 *Set of Simulations for Case Scenario Three*

Case	Layers	Permeability *k* md	Area *A* Acres	Fracture Half-Length *Lf* ft	Production Time *t* Months
	Top	0.1	160		
136	Middle	10	20	180	36
	Bottom	0.01	160		
	Top	0.1	160		
137	Middle	10	20	180	12
	Bottom	0.01	160		
	Top	0.1	160		
138	Middle	10	20	180	1
	Bottom	0.01	160		
	Top	0.1	80		
139	Middle	10	20	180	36
	Bottom	0.01	80		
	Top	0.1	80		
140	Middle	10	20	180	12
	Bottom	0.01	80		
	Top	0.1	80		
141	Middle	10	20	180	1
	Bottom	0.01	80		
	Top	0.1	160		
142	Middle	10	20	350	36
	Bottom	0.01	160		
	Top	0.1	160		
143	Middle	10	20	350	12
	Bottom	0.01	160		
	Top	0.1	160		
144	Middle	10	20	350	1
	Bottom	0.01	160		
	Top	0.1	80		
145	Middle	10	20	350	36
	Bottom	0.01	80		
	Top	0.1	80		
146	Middle	10	20	350	12
	Bottom	0.01	80		
	Top	0.1	80		
147	Middle	10	20	350	1
	Bottom	0.01	80		
	Top	0.1	160		
148	Middle	10	20	600	36
	Bottom	0.01	160		
	Top	0.1	160		
149	Middle	10	20	600	12
	Bottom	0.01	160		
	Top	0.1	160		
150	Middle	10	20	600	1
	Bottom	0.01	160		
	Top	0.1	80		
151	Middle	10	20	600	36
	Bottom	0.01	80		
	Top	0.1	80		
152	Middle	10	20	600	12
	Bottom	0.01	80		
	Top	0.1	80		
153	Middle	10	20	600	1
	Bottom	0.01	80		

APPENDIX B

TABLES OF RESULTS FROM HISTORY MATCH ANALYSIS

Table B.1 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 1-9*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	5	160	1.0	5	160	10	5	160
Bottom Layer:	0.01	95	160	0.01	95	160	0.01	95	160
Three Years of Production Data									
		Case 1			**Case 2**			**Case 3**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.45	1.29	-11.03	5.95	1.28	-78.49	50.95	**2.44**	-95.21
Lf, (ft)	180	178	-1.11	180	378	110.00	180	**422**	134.44
A, (acres)	160	52	-67.50	160	29	-81.88	160	**20**	-87.50
Forecast 1, (Bcf)	2.2	1.97	-10.45	2.51	2.15	-14.34	2.52	**1.65**	-34.52
Forecast 2, (Bcf)	2.2	2.34	6.36	2.51	3.29	31.08	2.52	**5.34**	111.90
One Year of Production Data									
		Case 4			**Case 5**			**Case 6**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.45	1.34	-7.59	5.95	3.45	-42.02	50.95	**4.74**	-90.70
Lf, (ft)	180	169	-6.11	180	142	-21.11	180	**360**	100.00
A, (acres)	160	35	-78.13	160	18	-88.75	160	**14**	-91.25
Forecast 1, (Bcf)	2.2	1.86	-15.45	2.51	1.53	-39.04	2.52	**1.32**	-47.62
Forecast 2, (Bcf)	2.2	2.37	7.73	2.51	4.5	79.28	2.52	**5.38**	113.49
One Month of Production Data									
		Case 7			**Case 8**			**Case 9**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.45	0.934	-35.59	5.95	5.48	-7.90	50.95	28.98	-43.12
Lf, (ft)	180	223	23.89	180	81	-55.00	180	45	-75.00
A, (acres)	160	7	-95.63	160	7	-95.63	160	10	-93.75
Forecast, 1 (Bcf)	2.2	0.58	-73.64	2.51	0.63	-74.90	2.52	0.76	-69.84
Forecast 2, (Bcf)	2.2	3.76	70.91	2.51	5.4	115.14	2.52	11.1	340.48

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light — Match with square area
Bold — Match with rectangular area

Table B.2 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 19-27*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	5	160	1.0	5	160	10	5	160
Bottom Layer:	0.01	95	160	0.01	95	160	0.01	95	160
Three Years of Production Data									
		Case 19			**Case 20**			**Case 21**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	1.1	-24.14	5.95	2.57	-56.81	50.95	**3.12**	-93.88
Lf, (ft)	600	622	3.67	600	557	-7.17	600	**547**	-8.83
A, (acres)	160	90	-43.75	160	34	-78.75	160	**33**	-79.38
Forecast 1, (Bcf)	3.85	3.75	-2.60	4.01	2.92	-27.18	4.04	**2.97**	-26.49
Forecast 2, (Bcf)	3.85	4	3.90	4.01	5.94	48.13	4.04	**6.91**	71.04
One Year of Production Data									
		Case 22			**Case 23**			**Case 24**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	1.48	2.07	5.95	3.9	-34.45	50.95	**6.9**	-86.46
Lf, (ft)	600	494	-17.67	600	376	-37.33	600	**437**	-27.17
A, (acres)	160	49	-69.38	160	27	-83.13	160	**21**	-86.88
Forecast 1, (Bcf)	3.85	3.1	-19.48	4.01	2.47	-38.40	4.04	**1.8**	-55.45
Forecast 2, (Bcf)	3.85	4.2	9.09	4.01	6.71	67.33	4.04	**9.38**	132.18
One Month of Production Data									
		Case 25			**Case 26**			**Case 27**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	6.43	343.45	5.95	14.32	140.67	50.95	56.64	11.17
Lf, (ft)	600	170	-71.67	600	104	-82.67	600	53	-91.17
A, (acres)	160	7	-95.63	160	10	-93.75	160	12	-92.50
Forecast 1, (Bcf)	3.85	0.6	-84.42	4.01	0.93	-76.81	4.04	1.18	-70.79
Forecast 2, (Bcf)	3.85	7	81.82	4.01	9.43	135.16	4.04	13.19	226.49

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light — Match with square area; **Bold** — Match with rectangular area

Table B.3 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 28-36*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	5	80	1.0	5	80	10	5	80
Bottom Layer:	0.01	95	80	0.01	95	80	0.01	95	80
Three Years of Production Data									
		Case 28			**Case 29**			**Case 30**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.45	1.16	-20.00	5.95	0.76	-87.23	50.95	**1.29**	-97.47
Lf, (ft)	180	195	8.33	180	477	165.00	180	**393**	118.33
A, (acres)	80	38	-52.50	80	25	-68.75	80	**17**	-78.75
Forecast 1, (Bcf)	2.03	1.88	-7.39	2.1	1.77	-15.71	2.1	**1.46**	-30.48
Forecast 2, (Bcf)	2.03	2.18	7.39	2.1	2.62	24.76	2.1	**3.2**	52.38
One Year of Production Data									
		Case 31			**Case 32**			**Case 33**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.45	1.29	-11.03	5.95	2.1	-64.71	50.95	**3.04**	-94.03
Lf, (ft)	180	174	-3.33	180	209	16.11	180	**301**	67.22
A, (acres)	80	26	-67.50	80	13	-83.75	80	**10**	-87.50
Forecast 1, (Bcf)	2.03	1.65	-18.72	2.1	1.19	-43.33	2.1	**0.93**	-55.71
Forecast 2, (Bcf)	2.03	2.43	19.70	2.1	3.28	56.19	2.1	**4.43**	110.95
One Month of Production Data									
		Case 34			**Case 35**			**Case 36**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.45	1.3162	-9.23	5.95	5.44	-8.57	50.95	25.18	-50.58
Lf, (ft)	180	162	-10.00	180	81	-55.00	180	53	-70.56
A, (acres)	80	8	-90.00	80	6	-92.50	80	6	-92.50
Forecast 1, (Bcf)	2.03	0.69	-66.01	2.1	0.55	-73.81	2.1	0.53	-74.76
Forecast 2, (Bcf)	2.03	2.97	46.31	2.1	4.3	104.76	2.1	6.59	213.81

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

Table B.4 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 37-45*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	5	80	1.0	5	80	10	5	80
Bottom Layer:	0.01	95	80	0.01	95	80	0.01	95	80
Three Years of Production Data									
		Case 37			**Case 38**			**Case 39**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	1.07	-26.21	5.95	1.11	-81.34	50.95	**1.58**	-96.90
Lf, (ft)	350	387	10.57	350	533	52.29	350	**467**	33.43
A, (acres)	80	50	-37.50	80	32	-60.00	80	**24**	-70.00
Forecast 1, (Bcf)	2.7	2.55	-5.56	2.74	2.28	-16.79	2.74	**2.02**	-26.28
Forecast 2, (Bcf)	2.7	2.82	4.44	2.74	3.43	25.18	2.74	**3.83**	39.78
One Year of Production Data									
		Case 40			**Case 41**			**Case 42**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	1.16	-20.00	5.95	2.05	-65.55	50.95	**3.52**	-93.09
Lf, (ft)	350	362	3.43	350	342	-2.29	350	**354**	1.14
A, (acres)	80	49	-38.75	80	19	-76.25	80	**14**	-82.50
Forecast 1, (Bcf)	2.7	2.4	-11.11	2.74	1.65	-39.78	2.74	**1.25**	-54.38
Forecast 2, (Bcf)	2.7	2.88	6.67	2.74	3.85	40.51	2.74	**4.91**	79.20
One Month of Production Data									
		Case 43			**Case 44**			**Case 45**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	2.69	85.52	5.95	5.8	-2.52	50.95	25	-50.93
Lf, (ft)	350	212	-39.43	350	151	-56.86	350	82	-76.57
A, (acres)	80	6	-92.50	80	7	-91.25	80	7	-91.25
Forecast 1, (Bcf)	2.7	0.53	-80.37	2.74	0.69	-74.82	2.74	0.61	-77.74
Forecast 2, (Bcf)	2.7	3.73	38.15	2.74	4.93	79.93	2.74	6.78	147.45

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

Table B.5 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 46-54*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	5	80	1.0	5	80	10	5	80
Bottom Layer:	0.01	95	80	0.01	95	80	0.01	95	80
Three Years of Production Data									
	Case 46			**Case 47**			**Case 48**		
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	0.95	-34.48	5.95	**1.7**	-71.43	50.95	**1.93**	-96.21
Lf, (ft)	600	684	14.00	600	**570**	-5.00	600	**550**	-8.33
A, (acres)	80	68	-15.00	80	**36**	-55.00	80	**34**	-57.50
Forecast 1, (Bcf)	3.42	3.36	-1.75	3.45	**2.81**	-18.55	3.48	**2.73**	-21.55
Forecast 2, (Bcf)	3.42	3.55	3.80	3.45	**4.32**	25.22	3.48	**4.5**	29.31
One Year of Production Data									
	Case 49			**Case 50**			**Case 51**		
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	1.49	2.76	5.95	2.96	-50.25	50.95	**4.05**	-92.05
Lf, (ft)	600	491	-18.17	600	441	-26.50	600	**411**	-31.50
A, (acres)	80	40	-50.00	80	21	-73.75	80	**19**	-76.25
Forecast 1, (Bcf)	3.42	2.85	-16.67	3.45	1.92	-44.35	3.48	**1.79**	-48.56
Forecast 2, (Bcf)	3.42	3.81	11.40	3.45	4.91	42.32	3.48	**5.41**	55.46
One Month of Production Data									
	Case 52			**Case 53**			**Case 54**		
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	6.3	334.48	5.95	12.99	118.32	50.95	42.7448	-16.10
Lf, (ft)	600	173	-71.17	600	130	-78.33	600	78	-87.00
A, (acres)	80	7	-91.25	80	8	-90.00	80	7	-91.25
Forecast 1, (Bcf)	3.42	0.59	-82.75	3.45	0.78	-77.39	3.48	0.68	-80.46
Forecast 2, (Bcf)	3.42	5.26	53.80	3.45	6.22	80.29	3.48	7.2	106.90

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

Table B.6 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 55-63*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	5	40	1.0	5	40	10	5	40
Bottom Layer:	0.01	95	40	0.01	95	40	0.01	95	40
				Three Years of Production Data					
		Case 55			**Case 56**			**Case 57**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.45	0.96	-33.79	5.95	0.42	-92.94	50.95	**0.66**	-98.70
Lf, (ft)	180	227	26.11	180	554	207.78	180	**432**	140.00
A, (acres)	40	29	-27.50	40	34	-15.00	40	**21**	-47.50
Forecast 1, (Bcf)	1.74	1.66	-4.60	1.75	1.78	1.71	1.75	**1.46**	-16.57
Forecast 2, (Bcf)	1.74	1.82	4.60	1.75	1.66	-5.14	1.75	**2.01**	14.86
				One Year of Production Data					
		Case 58			**Case 59**			**Case 60**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.45	1.17	-19.31	5.95	1.08	-81.85	50.95	**1.677**	-96.71
Lf, (ft)	180	188	4.44	180	318	76.67	180	**282**	56.67
A, (acres)	40	20	-50.00	40	12	-70.00	40	**9**	-77.50
Forecast 1, (Bcf)	1.74	1.4	-19.54	1.75	1.03	-41.14	1.75	**0.78**	-55.43
Forecast 2, (Bcf)	1.74	1.9	9.20	1.75	2.21	26.29	1.75	**2.55**	45.71
				One Month of Production Data					
		Case 61			**Case 62**			**Case 63**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.45	1.29	-11.03	5.95	4.64	-22.02	50.95	16.62	-67.38
Lf, (ft)	180	179	-0.56	180	103	-42.78	180	81	-55.00
A, (acres)	40	4	-90.00	40	4	-90.00	40	4	-90.00
Forecast 1, (Bcf)	1.74	0.41	-76.44	1.75	0.39	-77.71	1.75	0.36	-79.43
Forecast 2, (Bcf)	1.74	2.06	18.39	1.75	2.91	66.29	1.75	3.55	102.86

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

Table B.7 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 64-72*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	5	40	1.0	5	40	10	5	40
Bottom Layer:	0.01	95	40	0.01	95	40	0.01	95	40
Three Years of Production Data									
		Case 64			**Case 65**			**Case 66**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	0.81	-44.14	5.95	0.914	-84.64	50.95	**1.03**	97.98
Lf, (ft)	350	464	32.57	350	512	46.29	350	**483**	-38.00
A, (acres)	40	38	-5.00	40	29	-27.50	40	**26**	35.00
Forecast 1, (Bcf)	2.23	2.2	-1.35	2.24	2.05	-8.48	2.24	**1.95**	-12.95
Forecast 2, (Bcf)	2.23	2.28	2.24	2.24	2.45	9.38	2.24	**2.51**	12.05
One Year of Production Data									
		Case 67			**Case 68**			**Case 69**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	0.939	-35.24	5.95	1.61	-72.94	50.95	**2.19**	-95.70
Lf, (ft)	350	416	18.86	350	379	8.29	350	**341**	-2.57
A, (acres)	40	32	-20.00	40	16	-60.00	40	**13**	-67.50
Forecast 1, (Bcf)	2.23	1.98	-11.21	2.24	1.4	-37.50	2.24	**1.14**	-49.11
Forecast 2, (Bcf)	2.23	2.3	3.14	2.24	2.71	20.98	2.24	**2.91**	29.91
One Month of Production Data									
		Case 70			**Case 71**			**Case 72**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	2.69	85.52	5.95	5.8514	-1.66	50.95	14.258	-72.02
Lf, (ft)	350	212	-39.43	350	149	-57.43	350	138	-60.57
A, (acres)	40	6	-85.00	40	6	-85.00	40	5	-87.50
Forecast 1, (Bcf)	2.23	0.51	-77.13	2.24	0.52	-76.79	2.24	0.41	-81.70
Forecast 2, (Bcf)	2.23	2.78	24.66	2.24	3.31	47.77	2.24	3.58	59.82

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area
Bold: Match with rectangular area

Table B.8 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 73-81*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	5	40	1.0	5	40	10	5	40
Bottom Layer:	0.01	95	40	0.01	95	40	0.01	95	40
Three Years of Production Data									
		Case 73			**Case 74**			**Case 75**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	1.29	-11.03	5.95	**1.53**	-74.29	50.95	**1.62**	-96.82
Lf, (ft)	600	555	-7.50	600	**520**	-13.33	600	**514**	-14.33
A, (acres)	40	34	-15.00	40	**30**	-25.00	40	**29**	-27.50
Forecast 1, (Bcf)	2.64	2.51	-4.92	2.65	**2.38**	-10.19	2.66	**2.35**	-11.65
Forecast 2, (Bcf)	2.64	2.79	5.68	2.65	**2.91**	9.81	2.66	**2.95**	10.90
One Year of Production Data									
		Case 76			**Case 77**			**Case 78**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	1.675	15.52	5.95	**2.51**	-57.82	50.95	**2.83**	-94.45
Lf, (ft)	600	450	-25.00	600	**412**	-31.33	600	**401**	-33.17
A, (acres)	40	27	-32.50	40	**19**	-52.50	40	**18**	-55.00
Forecast 1, (Bcf)	2.64	2.19	-17.05	2.65	**1.69**	-36.23	2.66	**1.61**	-39.47
Forecast 2, (Bcf)	2.64	2.9	9.85	2.65	**3.15**	18.87	2.66	**3.2**	20.30
One Month of Production Data									
		Case 79			**Case 80**			**Case 81**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.45	7.68	429.66	5.95	12.7	113.45	50.95	15.68	-69.22
Lf, (ft)	600	131	-78.17	600	130	-78.33	600	214	-64.33
A, (acres)	40	6	-85.00	40	7	-82.50	40	6	-85.00
Forecast 1, (Bcf)	2.64	0.57	-78.41	2.65	0.56	-78.87	2.66	0.51	-80.83
Forecast 2, (Bcf)	2.64	3.31	25.38	2.65	3.59	35.47	2.66	3.65	37.22

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

Table B.9 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 82-90*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	40	1.0	10	40	10	10	40
Bottom Layer:	0.01	90	160	0.01	90	160	0.01	90	160
Three Years of Production Data									
		Case 82			**Case 83**			**Case 84**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.9	0.933	-50.89	10.9	**1.051**	-90.36	100.9	**1.31**	-98.70
Lf, (ft)	180	281	56.11	180	**402**	123.33	180	**374**	107.78
A, (acres)	160	29	-81.88	160	**18**	-88.75	160	**16**	-90.00
Forecast 1, (Bcf)	2.02	1.75	-13.37	2.03	**1.47**	-27.59	2.03	**1.32**	-34.98
Forecast 2, (Bcf)	2.02	2.25	11.39	2.03	**2.9**	42.86	2.03	**3.31**	63.05
One Year of Production Data									
		Case 85			**Case 86**			**Case 87**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.9	1.47	-22.63	10.9	**2.13**	-80.46	100.9	**3.24**	-96.79
Lf, (ft)	180	184	2.22	180	**312**	73.33	180	**288**	60.00
A, (acres)	160	18	-88.75	160	**11**	-93.13	160	**10**	-93.75
Forecast 1, (Bcf)	2.02	1.28	-36.63	2.03	**0.97**	-52.22	2.03	**0.8**	-60.59
Forecast 2, (Bcf)	2.02	2.64	30.69	2.03	**4.1**	101.97	2.03	**5.43**	167.49
One Month of Production Data									
		Case 88			**Case 89**			**Case 90**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.9	4.45	134.21	10.9	9.7	-11.01	100.9	43.19	-57.20
Lf, (ft)	180	55	-69.44	180	70	-61.11	180	58	-67.78
A, (acres)	160	3	-98.13	160	6	-96.25	160	5	-96.88
Forecast, 1 (Bcf)	2.02	0.23	-88.61	2.03	0.5	-75.37	2.03	0.4	-80.30
Forecast 2, (Bcf)	2.02	4.21	108.42	2.03	7.57	272.91	2.03	12.75	528.08

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

Table B.10 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 100-108*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	40	1.0	10	40	10	10	40
Bottom Layer:	0.01	90	160	0.01	90	160	0.01	90	160
Three Years of Production Data									
		Case 100			**Case 101**			**Case 102**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	1.2	-36.84	10.9	**1.71**	-84.31	100.9	**1.87**	-98.15
Lf, (ft)	600	638	6.33	600	**548**	-8.67	600	**538**	-10.33
A, (acres)	160	45	-71.88	160	**33**	-79.38	160	**32**	-80.00
Forecast 1, (Bcf)	3.47	3	-13.54	3.48	**2.63**	-24.43	3.52	**2.6**	-26.14
Forecast 2, (Bcf)	3.47	4.12	18.73	3.48	**4.9**	40.80	3.52	**5.11**	45.17
One Year of Production Data									
		Case 103			**Case 104**			**Case 105**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	1.913	0.68	10.9	**3.49**	-67.98	100.9	**4.09**	-95.95
Lf, (ft)	600	460.076	-23.32	600	**406**	-32.33	600	**398**	-33.67
A, (acres)	160	28	-82.50	160	**18**	-88.75	160	**17**	-89.38
Forecast 1, (Bcf)	3.47	2.35	-32.28	3.48	**1.68**	-51.72	3.52	**1.63**	-53.69
Forecast 2, (Bcf)	3.47	4.81	38.62	3.48	**6.49**	86.49	3.52	**7.09**	101.42
One Month of Production Data									
		Case 106			**Case 107**			**Case 108**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	9.16	382.11	10.9	21.9674	101.54	100.9	24.38	-75.84
Lf, (ft)	600	125	-79.17	600	88	-85.33	600	219	-63.50
A, (acres)	160	7	-95.63	160	8	-95.00	160	7	-95.63
Forecast 1, (Bcf)	3.47	0.69	-80.12	3.48	0.46	-86.78	3.52	0.52	-85.23
Forecast 2, (Bcf)	3.47	7.62	119.60	3.48	10.98	215.52	3.52	12.48	254.55

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

Table B.11 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 109-117*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	20	1.0	10	20	10	10	20
Bottom Layer:	0.01	90	160	0.01	90	160	0.01	90	160
Three Years of Production Data									
		Case 109			**Case 110**			**Case 111**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.9	0.525	-72.37	10.9	**0.557**	-94.89	100.9	**0.683**	-99.32
Lf, (ft)	180	400	122.22	180	**454**	152.22	180	**400**	122.22
A, (acres)	160	36	-77.50	160	**23**	-85.63	160	**19**	-88.13
Forecast 1, (Bcf)	1.85	1.7	-8.11	1.87	**1.5**	-19.79	1.87	**1.37**	-26.74
Forecast 2, (Bcf)	1.85	1.86	0.54	1.87	**2.09**	11.76	1.87	**2.22**	18.72
One Year of Production Data									
		Case 112			**Case 113**			**Case 114**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.9	1.024	-46.11	10.9	**1.47**	-86.51	100.9	**1.697**	-98.32
Lf, (ft)	180	239	32.78	180	**283**	57.22	180	**272**	51.11
A, (acres)	160	15	-90.63	160	**9**	-94.38	160	**8**	-95.00
Forecast 1, (Bcf)	1.85	1.19	-35.68	1.87	**1.2**	-35.83	1.87	**0.72**	-61.50
Forecast 2, (Bcf)	1.85	2.22	20.00	1.87	**3.15**	68.45	1.87	**3.41**	82.35
One Month of Production Data									
		Case 115			**Case 116**			**Case 117**	
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)
kh, (md-ft)	1.9	1.22	-35.79	10.9	8.166	-25.08	100.9	16.654	-83.49
Lf, (ft)	180	211	17.22	180	92	-48.89	180	152	-15.56
A, (acres)	160	8	-95.00	160	4	-97.50	160	3	-98.13
Forecast 1, (Bcf)	1.85	0.69	-62.70	1.87	0.38	-79.68	1.87	0.4	-78.61
Forecast 2, (Bcf)	1.85	2.41	30.27	1.87	7	274.33	1.87	10.51	462.03

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light — Match with square area; **Bold** — Match with rectangular area

Table B.12 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 118-126*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	20	1.0	10	20	10	10	20
Bottom Layer:	0.01	90	160	0.01	90	160	0.01	90	160
Three Years of Production Data									
		Case 118			**Case 119**			**Case 120**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	0.588	-69.05	10.9	**0.777**	-92.87	100.9	**0.821**	-99.19
Lf, (ft)	350	600	71.43	350	**535**	52.86	350	**519**	48.29
A, (acres)	160	46	-71.25	160	**32**	-80.00	160	**30**	-81.25
Forecast 1, (Bcf)	2.51	2.25	-10.36	2.52	**2.05**	-18.65	2.52	**2**	-20.63
Forecast 2, (Bcf)	2.51	2.61	3.98	2.52	**2.88**	14.29	2.52	**2.94**	16.67
One Year of Production Data									
		Case 121			**Case 122**			**Case 123**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	1.045	-45.00	10.9	**1.9**	-82.57	100.9	**2.0913**	-97.93
Lf, (ft)	350	428	22.29	350	**341**	-2.57	350	**330**	-5.71
A, (acres)	160	22	-86.25	160	**13**	-91.88	160	**12**	-92.50
Forecast 1, (Bcf)	2.51	1.7	-32.27	2.52	**1.18**	-53.17	2.52	**1.11**	-55.95
Forecast 2, (Bcf)	2.51	3.01	19.92	2.52	**4.13**	63.89	2.52	**4.32**	71.43
One Month of Production Data									
		Case 124			**Case 125**			**Case 126**	
Units	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	3.222	69.58	10.9	9.251	-15.13	100.9	17.282	-82.87
Lf, (ft)	350	204	-41.71	350	132	-62.29	350	188	-46.29
A, (acres)	160	6	-96.25	160	5	-96.88	160	4	-97.50
Forecast 1, (Bcf)	2.51	0.55	-78.09	2.52	0.41	-83.73	2.52	0.34	-86.51
Forecast 2, (Bcf)	2.51	4.79	90.84	2.52	8.01	217.86	2.52	11.01	336.90

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area
Bold: Match with rectangular area

***Table B.13** Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 127-135*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	20	1.0	10	20	10	10	20
Bottom Layer:	0.01	90	160	0.01	90	160	0.01	90	160
Three Years of Production Data									
	Case 127			**Case 128**			**Case 129**		
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	0.9169	-51.74	10.9	**1.136**	-89.58	100.9	**1.25157**	-98.76
Lf, (ft)	600	684	14.00	600	**609**	1.50	600	**590**	-1.67
A, (acres)	160	52	-67.50	160	**41**	-74.38	160	**39**	-75.63
Forecast 1, (Bcf)	3.32	2.94	-11.45	3.33	**2.81**	-15.62	3.36	**2.71**	-19.35
Forecast 2, (Bcf)	3.32	3.79	14.16	3.33	**4.03**	21.02	3.36	**4.15**	23.51
One Year of Production Data									
	Case 130			**Case 131**			**Case 132**		
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	1.749	-7.95	10.9	**2.488**	-77.17	100.9	**2.764**	-97.26
Lf, (ft)	600	470	-21.67	600	**406.77**	-32.21	600	**400**	-33.33
A, (acres)	160	25	-84.38	160	**18**	-88.75	160	**18**	-88.75
Forecast 1, (Bcf)	3.32	2.06	-37.95	3.33	**2.62**	-21.32	3.36	**1.6**	-52.38
Forecast 2, (Bcf)	3.32	4.56	37.35	3.33	**5.34**	60.36	3.36	**5.61**	66.96
One Month of Production Data									
	Case 133			**Case 134**			**Case 135**		
Units	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error(%)	Input Values	Calculated Values	error (%)
kh, (md-ft)	1.9	6.947	265.63	10.9	10.7028	-1.81	100.9	**21.085**	-79.10
Lf, (ft)	600	173	-71.17	600	231	-61.50	600	**212**	-64.67
A, (acres)	160	7	-95.63	160	6	-96.25	160	**5**	-96.88
Forecast 1, (Bcf)	3.32	0.6	-81.93	3.33	0.57	-82.88	3.36	**0.49**	-85.42
Forecast 2, (Bcf)	3.32	7.37	121.99	3.33	9.6	188.29	3.36	**11.87**	253.27

Forecast 1: Using History Matched Area
Forecast 2: Using 160 acres

Calculated Values = Light: Match with square area; **Bold**: Match with rectangular area

***Table B.14** Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 136-138*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	160
Middle Layer:	10	5	20
Bottom Layer:	0.01	85	160
Three Years of Production Data			
		Case 136	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	1.02	-98.03
Lf, (ft)	180	347	92.78
A, (acres)	160	160	0.00
Forecast 1, (Bcf)	2.54	2.66	4.72
One Year of Production Data			
		Case 137	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	0.4396	-99.15
Lf, (ft)	180	640	255.56
A, (acres)	160	78	-51.25
Forecast 1, (Bcf)	2.54	2.24	-11.81
One Month of Production Data			
		Case 138	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	8.05	-84.47
Lf, (ft)	180	158	-12.22
A, (acres)	160	3	-98.13
Forecast, 1 (Bcf)	2.54	0.24	-90.55

Forecast 1: Using History Matched Area
Forecast 2: Using 160 Acres

Calculated Values = Light Match with square Area
Bold Match with rectangular area

Table B.15 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 139-141*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	80
Middle Layer:	10	5	20
Bottom Layer:	0.01	85	80
Three Years of Production Data			
		Case 139	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	**0.607**	-98.83
Lf, (ft)	180	**494**	174.44
A, (acres)	80	**85**	6.25
Forecast 1, (Bcf)	2.23	**2.3**	3.14
One Year of Production Data			
		Case 140	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	**0.401**	-99.23
Lf, (ft)	180	**660**	266.67
A, (acres)	80	**81**	1.25
Forecast 1, (Bcf)	2.23	**2.18**	-2.24
One Month of Production Data			
		Case 141	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	7.83	-84.90
Lf, (ft)	180	154	-14.44
A, (acres)	80	3	-96.25
Forecast 1, (Bcf)	2.23	0.22	-90.13

Forecast 1: Using History Matched Area
Forecast 2: Using 160 Acres

Calculated Values = Light Match with square Area
Bold Match with rectangular area

Table B.16 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 145-147*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	80
Middle Layer:	10	5	20
Bottom Layer:	0.01	85	80
	Three Years of Production Data		
		Case 145	
Units	Input Values	Calculated Values	error (%)
kh, (md-ft)	51.85	**0.459**	-99.11
Lf, (ft)	350	**923**	163.71
A, (acres)	80	**101**	26.25
Forecast 1, (Bcf)	2.85	**2.9**	1.75
	One Year of Production Data		
		Case 146	
Units	Input Values	Calculated Values	error (%)
kh, (md-ft)	51.85	**0.426**	-99.18
Lf, (ft)	350	**971**	177.43
A, (acres)	80	**160**	100.00
Forecast 1, (Bcf)	2.85	**3.02**	5.96
	One Month of Production Data		
		Case 147	
Units	Input Values	Calculated Values	error (%)
kh, (md-ft)	51.85	9.676	-81.34
Lf, (ft)	350	189	-46.00
A, (acres)	80	4	-95.00
Forecast 1, (Bcf)	2.85	0.38	-86.67

Forecast 1: Using History Matched Area
Forecast 2: Using 160 Acres

Calculated Values = Light Match with square Area
Bold Match with rectangular area

Table B.17 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 148-150*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	160
Middle Layer:	10	5	20
Bottom Layer:	0.01	85	160
Three Years of Production Data			
		Case 148	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	0.801	-98.46
Lf, (ft)	600	1000	66.67
A, (acres)	160	121	-24.38
Forecast 1, (Bcf)	4.19	4.19	0.00
One Year of Production Data			
		Case 149	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	1.534	-97.04
Lf, (ft)	600	664	10.67
A, (acres)	160	49	-69.38
Forecast 1, (Bcf)	4.19	3.41	-18.62
One Month of Production Data			
		Case 150	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	11.853	-77.14
Lf, (ft)	600	228	-62.00
A, (acres)	160	6	-96.25
Forecast 1, (Bcf)	4.19	0.53	-87.35

Forecast 1: Using History Matched Area
Forecast 2: Using 160 Acres

Calculated Values = Light Match with square Area
Bold Match with rectangular area

Table B.18 *Percentage Error in Calculated Values from History Match Analysis, Simulation Cases 151-153*

	Permeability (k) md	Layer Thickness (h) ft	Area (A) acres
Top Layer:	0.1	10	80
Middle Layer:	10	5	20
Bottom Layer:	0.01	85	80
Three Years of Production Data			
		Case 151	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	**1.571**	-96.97
Lf, (ft)	600	**634**	5.67
A, (acres)	80	**45**	-43.75
Forecast 1, (Bcf)	3.57	**3.26**	-8.68
One Year of Production Data			
		Case 152	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	**2.272**	-95.62
Lf, (ft)	600	**515**	-14.17
A, (acres)	80	**29**	-63.75
Forecast 1, (Bcf)	3.57	**2.51**	-29.69
One Month of Production Data			
		Case 153	
Units	Input Values	Calculated Values	error(%)
kh, (md-ft)	51.85	11.999	-76.86
Lf, (ft)	600	228	-62.00
A, (acres)	80	6	-92.50
Forecast 1, (Bcf)	3.57	0.51	-85.71

Forecast 1: Using History Matched Area
Forecast 2: Using 160 Acres

Calculated Values = Light   Match with square Area
Bold   Match with rectangular area

APPENDIX C

FIGURES OF TEN-YEAR GAS PRODUCTION FORECASTS

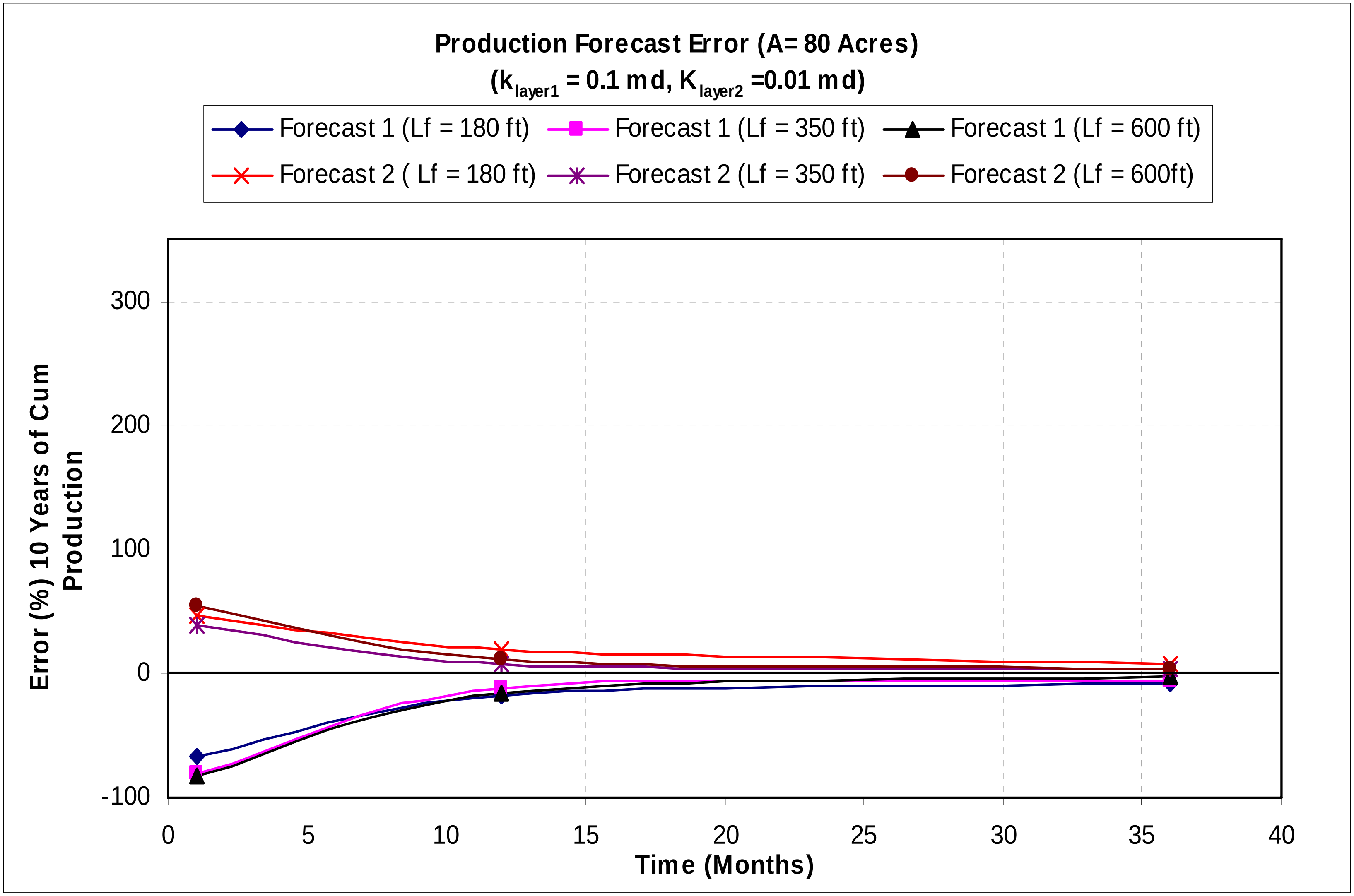

Fig C.1 *Production Forecast Error Scenario One (A=80 acres, k_{layer1}= 0.1md, K_{layer2}=0.01 md)*

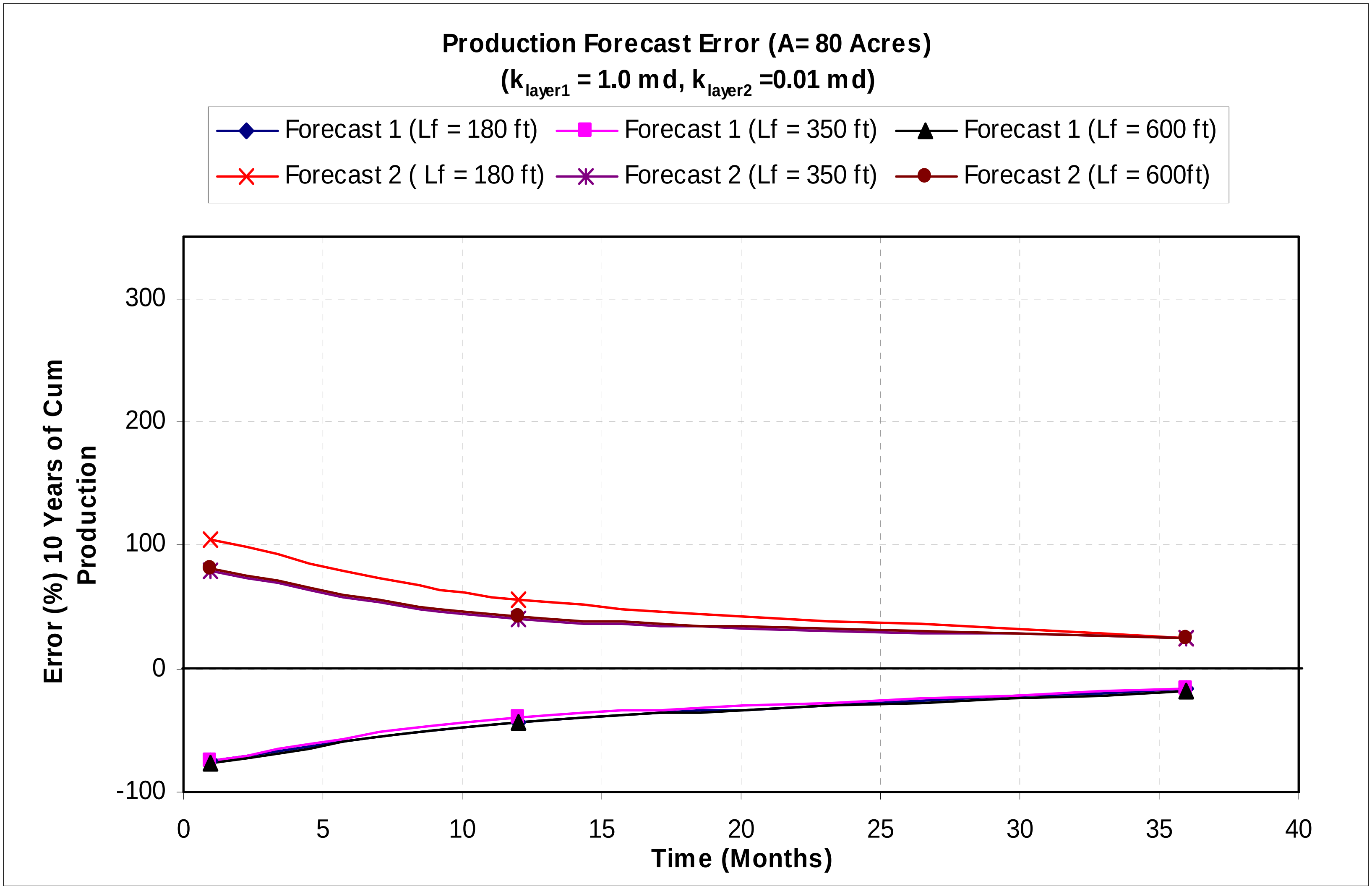

Fig C.2 *Production Forecast Error Scenario One (A=80 acres, k_{layer1}= 1.0 md, K_{layer2}=0.01 md)*

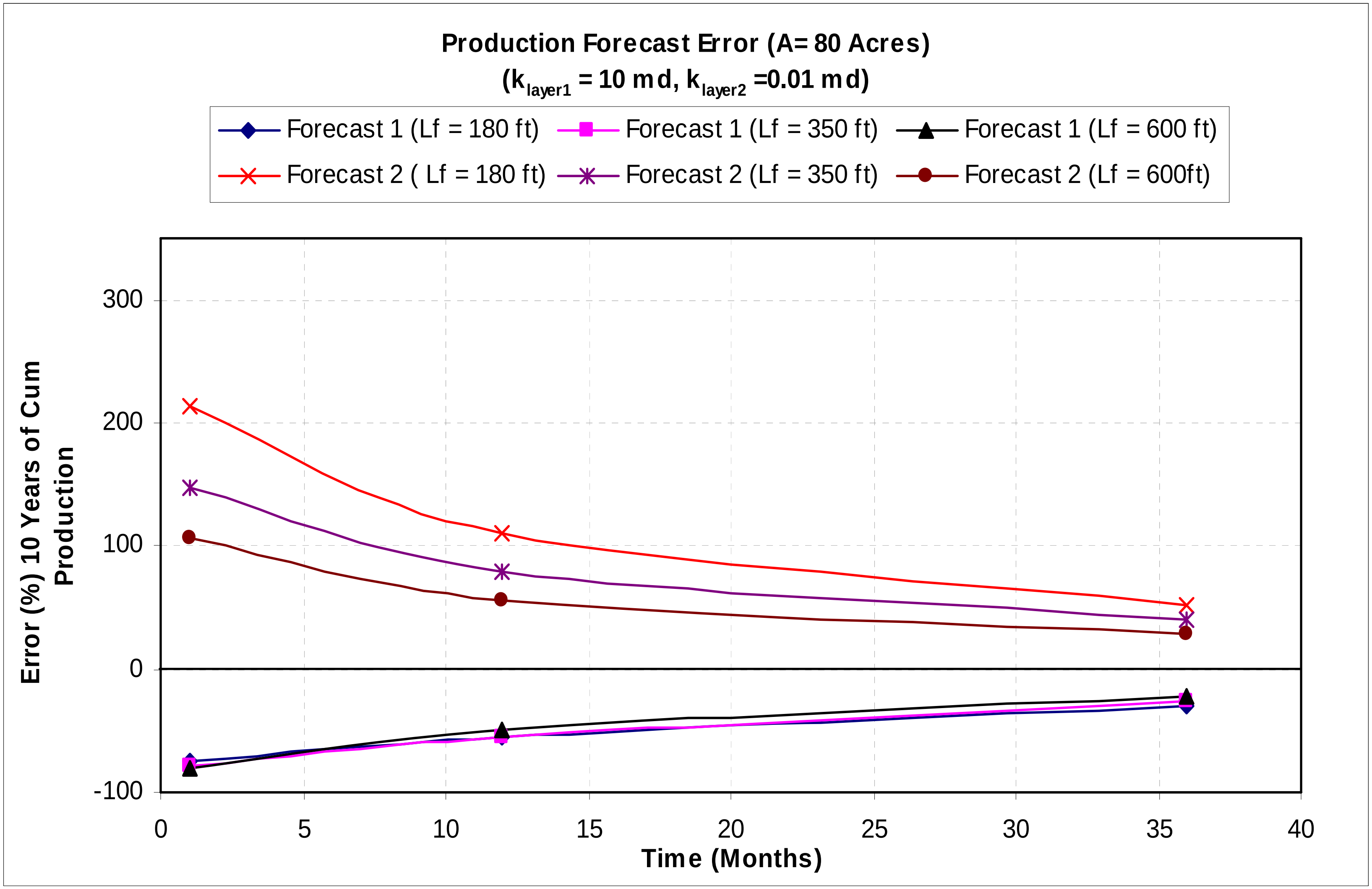

Fig C.3 *Production Forecast Error Scenario One (A=80 acres, k_{layer1}= 10 md, K_{layer2}=0.01 md)*

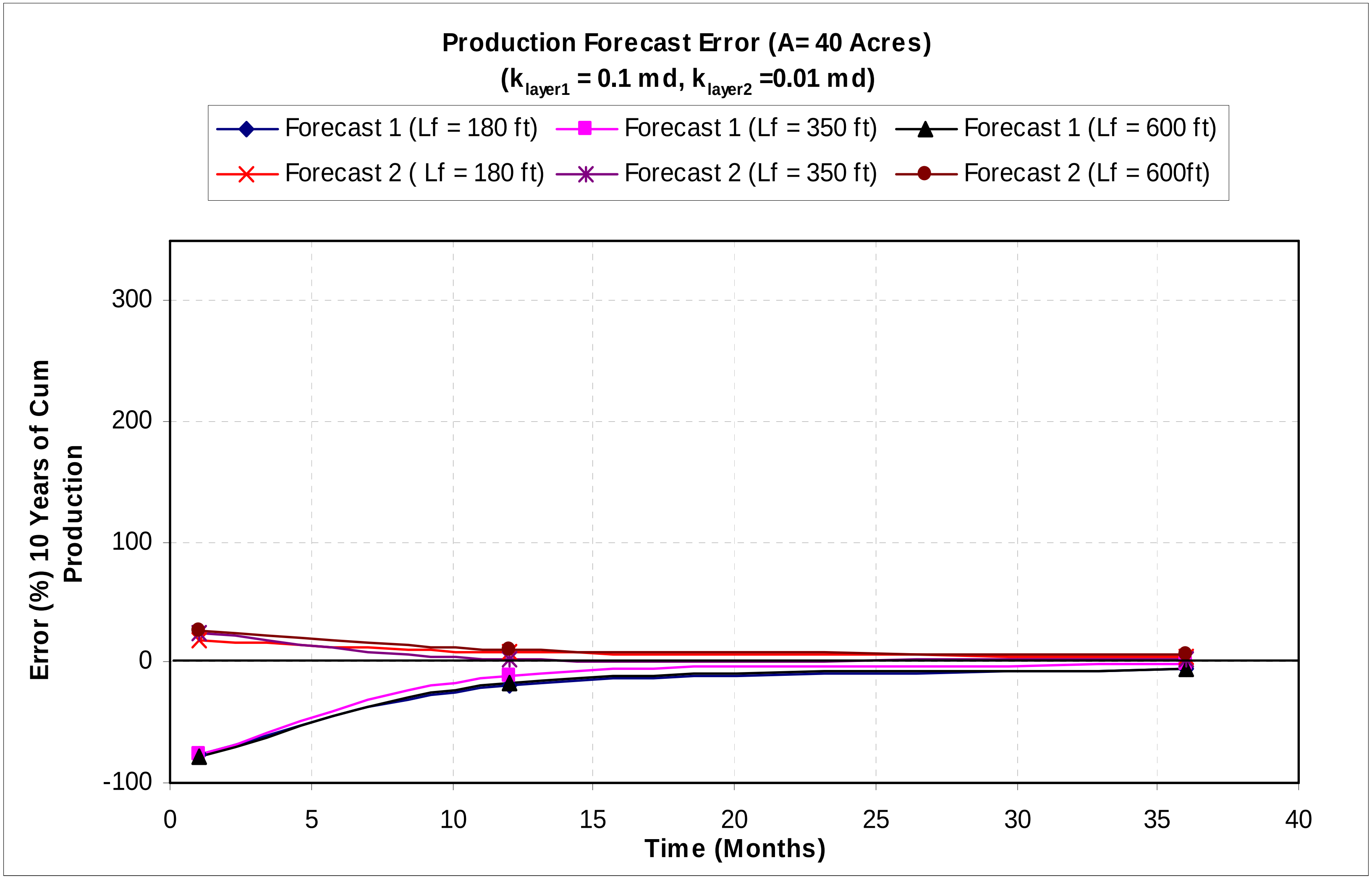

Fig C.4 *Production Forecast Error Scenario One (A=40 acres, k_{layer1}= 0.1md, K_{layer2}=0.01 md)*

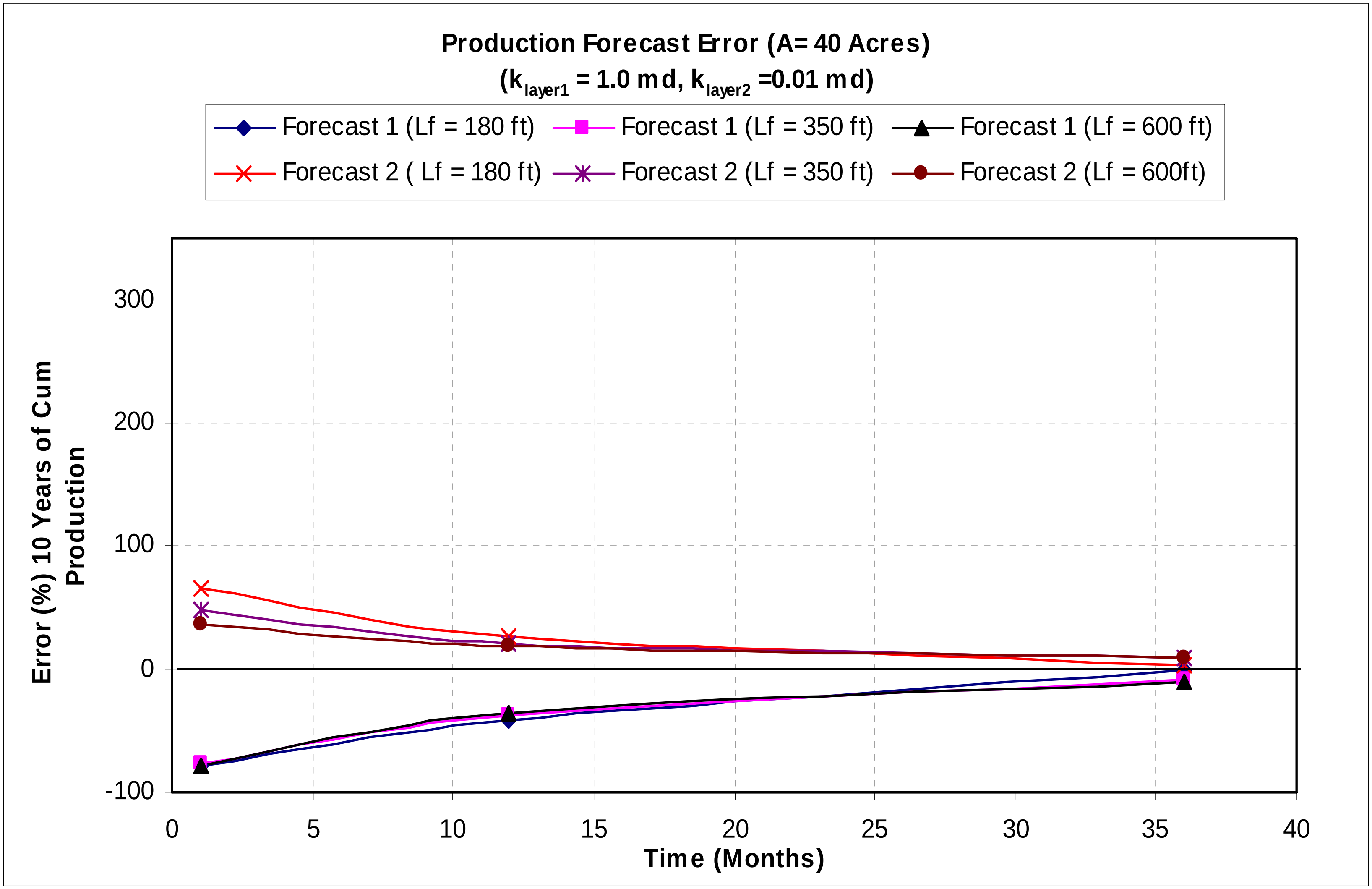

Fig C.5 *Production Forecast Error Scenario One (A=40 acres, k_{layer1}= 1.0 md, K_{layer2}=0.01 md)*

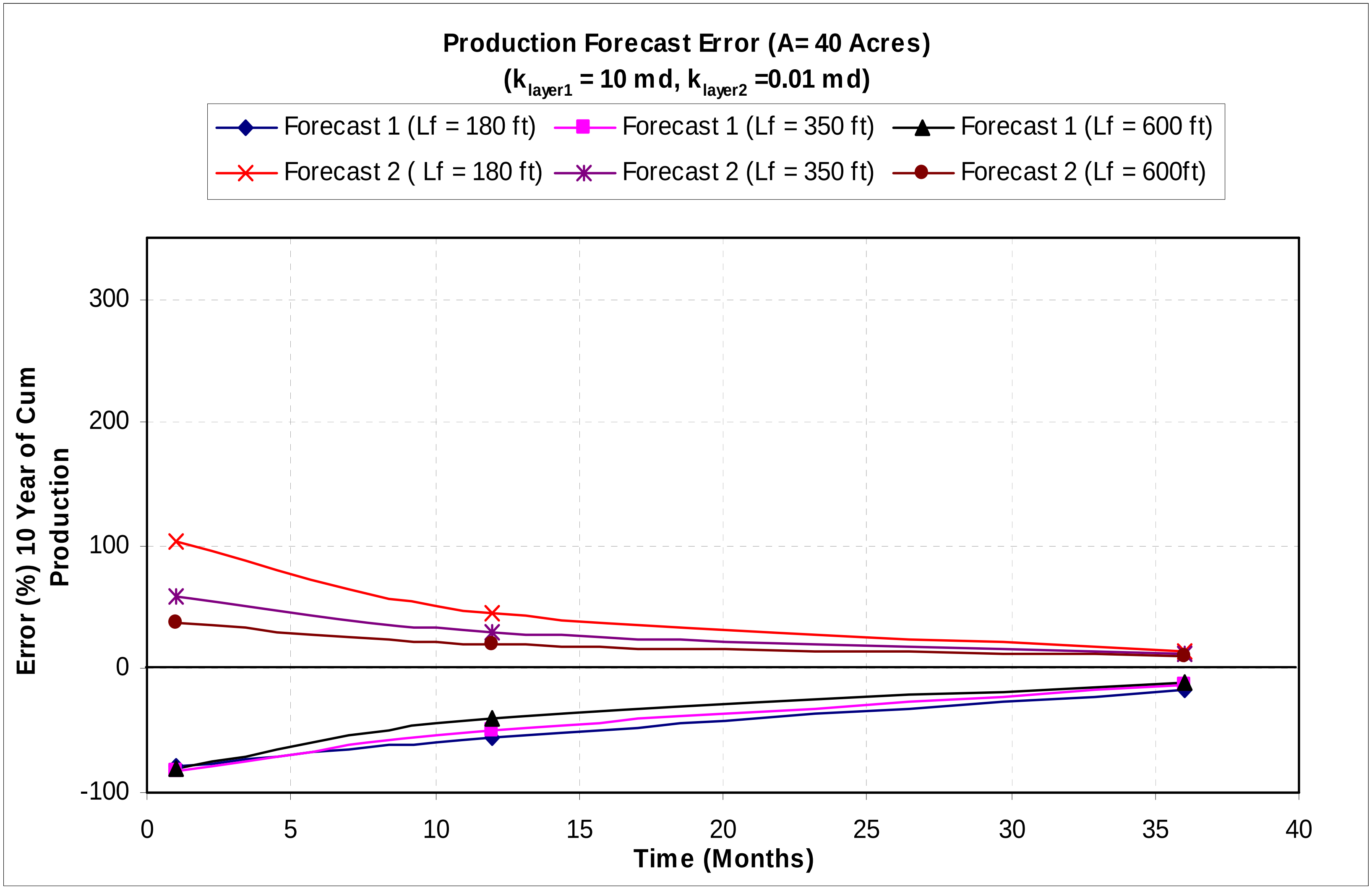

Fig C.6 *Production Forecast Error Scenario One (A=40 acres, k_{layer1}= 10 md, K_{layer2}=0.01 md)*

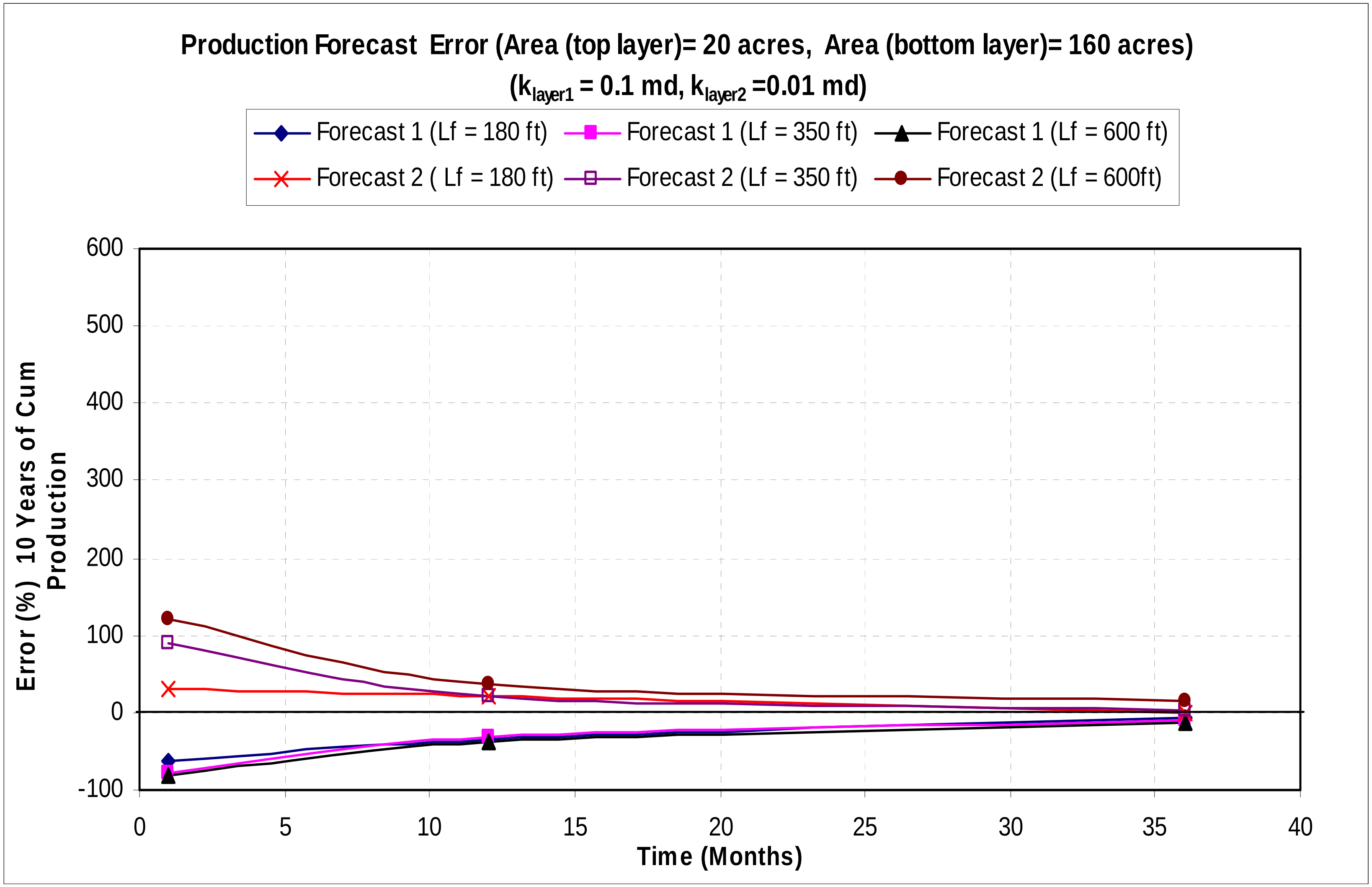

Fig C.7 *Production Forecast Error Scenario Two (A_{layer1}=20 acres, A_{layer2}=160 acres, k_{layer1}= 0.1md, k_{layer2}=0.01 md)*

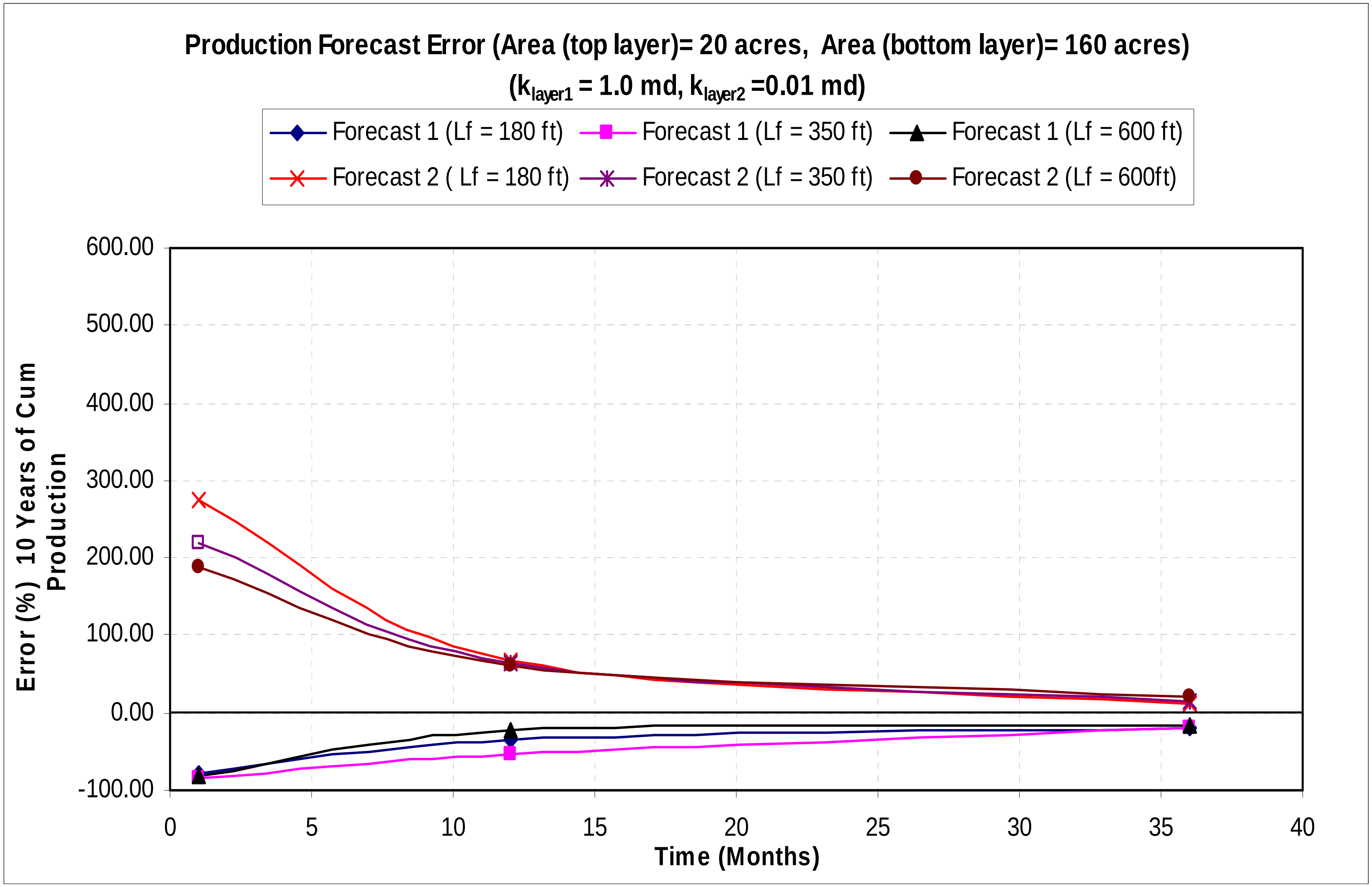

Fig C.8 *Production Forecast Error Scenario Two (A_{layer1}=20 acres, A_{layer2}=160 acres, k_{layer1}= 1.0 md, k_{layer2}=0.01 md)*

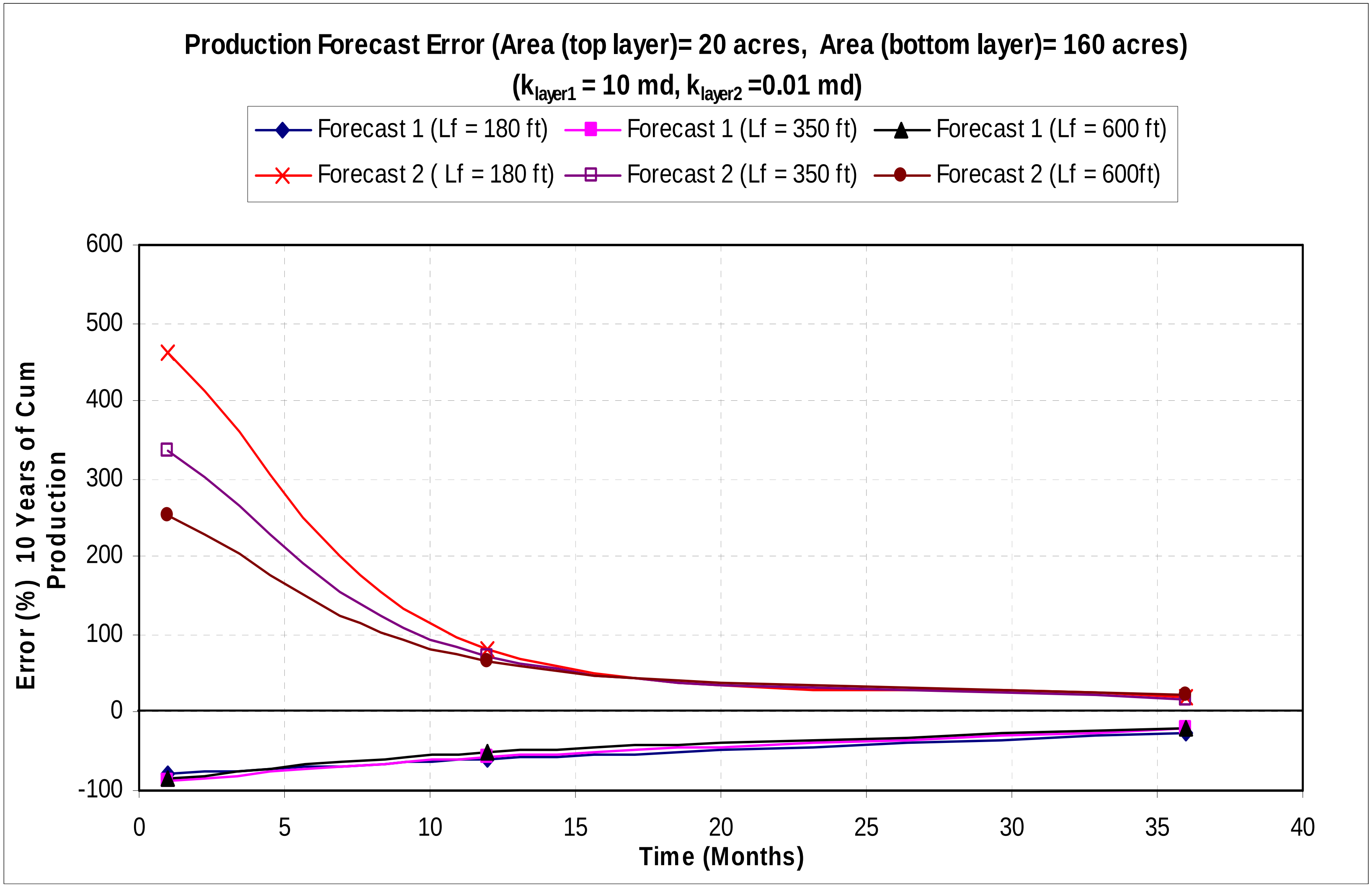

Fig C.9 *Production Forecast Error Scenario Two (A_{layer1}=20 acres, A_{layer2}=160 acres, k_{layer1}= 10md, k_{layer2}=0.01 md)*

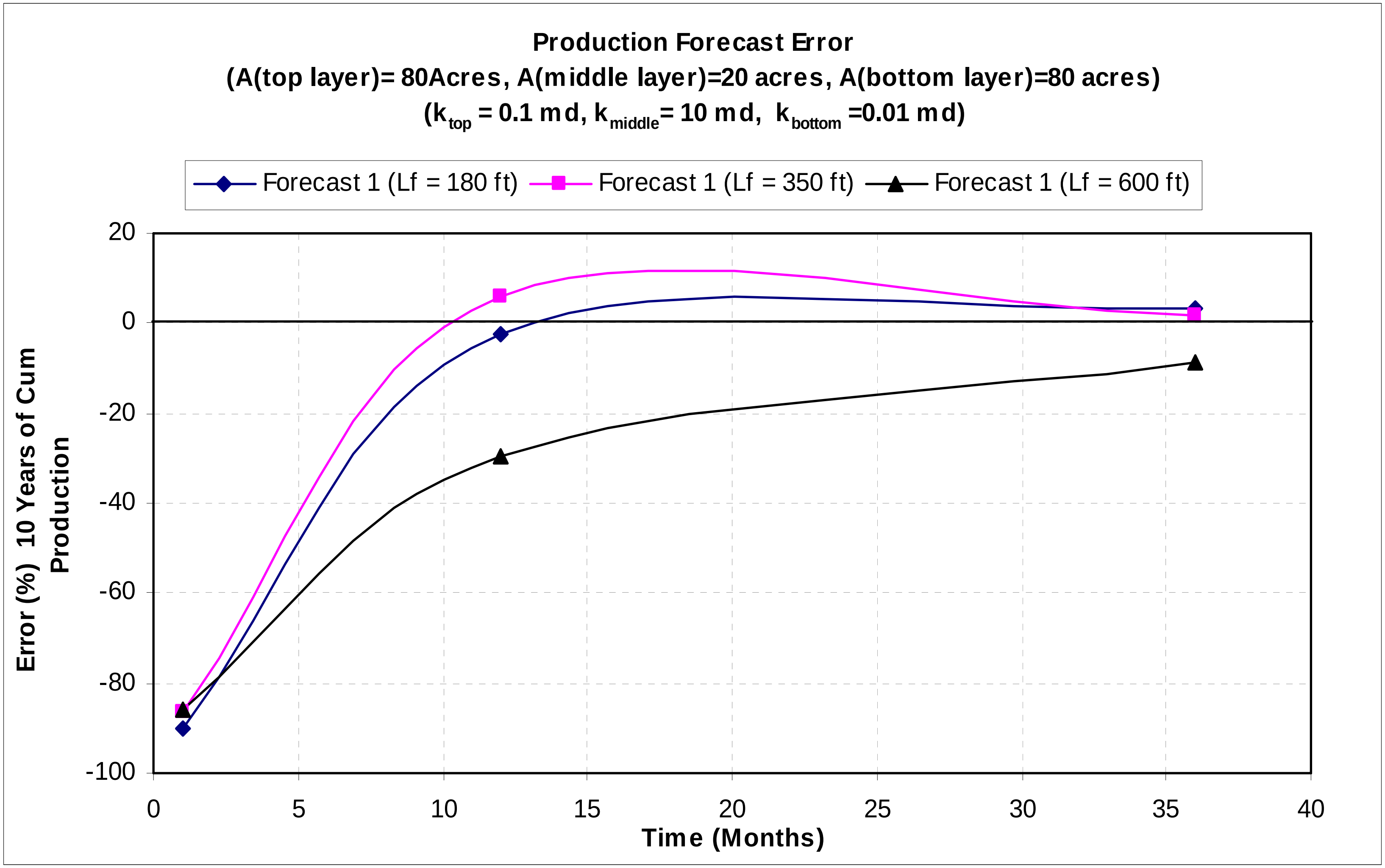

Fig C.10 *Production Forecast Error Scenario Three ($A_{top\ layer}$=80 acres, $A_{middle\ layer}$ =20acres, $A_{bottom\ layer}$=80acres k_{top}= 0.1md, k_{middle}=0.01 md k_{bottom}=0.01 md)*

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