Reservoir Pressure and Skin from Production Data Using the Reciprocal Productivity Index Method (The Intercept Method)

By

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Abstract

The reservoir average pressure can now be evaluated from routinely available rate and flowing pressure production data, using an extension of the reciprocal productivity index method. Traditionally, reservoir average pressure could only be determined from an extended duration build-up test. Especially in low permeability, stimulated reservoirs, that procedure generally tends to underestimate the pressure, due to practical limitations on shut-in times. In addition, an error in the reservoir average pressure determination results in an error in the computed skin for the well. However, this new procedure provides an independent evaluation of skin and pressure so that they are not dependent on one another. The theory for the method is explained and two example field applications are included.

Introduction

For very practical reasons, such as stimulation design, reserves assessment, etc., direct knowledge of the reservoir average pressure would be extremely useful. Currently, the only method available is to conduct an extended build-up test. It must then be evaluated using the classic Horner[1] or possibly Miller, Dyes and Hutchinson[2] evaluation procedures. This process has several serious limitations, especially the loss of revenue and damage to the well[3] arising from the extended duration shut-in. Particularly in massive hydraulically fracture stimulated wells, the overprint of the stimulation and the low reservoir permeability bias the predicted pressure (called P*). As a consequence of using the procedure outlined in this paper, the long-standing concern that the classic build-up analysis for "P*" underestimates the actual reservoir pressure is being confirmed.

The realization that reservoir average pressure could be estimated from production data became apparent from the many example production histories evaluated with the Reciprocal Productivity Index method[4,5] (RPI). The common evaluation strategy was to assume an initial pressure based on data from other sources (such as a build-up), then conduct the RPI analysis. In cases where large, rapid changes in flowing back-pressure occurred, the RPI-MDH plot often showed a signature which appeared to be skin at the time of the pressure change, but where no change in skin was justifiable. Further, the shift of the line's intercept could be removed by guessing new values of initial pressure. In several cases, data from other sources confirmed that the "new" guess was a better choice than the original value. That led to an examination of the mathematics to determine whether that observation was accidental or had theoretical justification.

Theory

The theoretical basis arises from the classic expression for a well's transient behavior as shown in Appendix A. There the necessary rearrangement is shown to obtain the two relationships, from which the initial pressure (pseudo-potential) and skin can be determined. They are:

$$I(t) = \Psi_i \frac{1}{q_s} - \frac{S}{P_{DC}} \quad (1$$

and

$$q_s\, I(t) = \Psi_i - q_s \frac{S}{P_{DC}} \quad (2$$

The definition for I(t) arises from the parameters which are known or given after the determination of effective permeability from the semi-log RPI-MDH plot. It represents the "intercept" ("y" value) for each of the observed points in the data set. It simply remains to plot the reciprocal rates versus I(t) for Eqn. 1 or the given rates versus q_s times I(t) for Eqn. 2.

For Eqn. 1, the graph shows the initial pseudo-potential as the slope and the intercept is the skin divided by P_{DC}, when plotting I(t) on the y axis and the reciprocal of the rate on the x axis. If the well experiences changing skin, the line's slope should remain constant, but "step changes" in the intercept should occur. As the well enters pseudo-steady state (depletion), the slope of the line begins to lessen, because the reservoir average pressure is dropping. This provides an independent means to test the pore volume depletion calculations (See Example 2). The upper "edge" of the data "cloud" represents the least damage situation, because the sign on the group is negative. Therefore, that is consistent with the "leading-edge" interpretation scheme for the RPI method.

It may be advantageous to use graphs plotted according to Eqn. 2, as well. Although, they do not actually provide new information, occasionally the different perspective it offers can be useful. In this case, the intercept of the graph represents the reservoir average pseudo-potential and its slope is skin divided by P_{DC}. Here, the rate appears on the x axis and the rate times I(t) is on the y axis.

A certain level of skepticism might exist about the uniqueness of this evaluation strategy. Certainly, the noise that usually exists in production data or the lack of a reasonably wide range of rates will increase the difficulty of uniquely evaluating the reservoir average pressure.

However, from a mathematical point of view, the solution is unique. Equation D of Appendix A actually shows an equation which can be recast so that it is a flat three-dimensional surface. Thus, assuming that there are sufficient points to delineate that surface, a single, unique solution exists. In other words, even though the determination of the permeability, pressure, drained area and skin are iterative, if the data were noise-free, a specific unique solution does exist. The solution strategy is iterative, because the initial guess at reservoir pressure determines the fluid density used to calculate the subsequent estimate of effective permeability, hence pressure, etc.

Examples

Two examples are provided to demonstrate the "Intercept" evaluation procedure. The first example is a well which received a massive hydraulic fracture stimulation, then commenced flowback. The second example is a typical, relatively long-term production history from which the effects of depletion can be observed. In both cases, the descriptive data has been modified from actual to disguise the source of the actual data set, i.e. only the production rates, pressures and times are real.

The Flowback

Figure 1 shows the rate and pressure history for the Example 1 Flowback. Particularly, notice the sharp change in flowing back pressure about three days into the clean-up. The change in wellhead pressure conditions appear to induce a new transient, as evidenced by the increase in rate. The analysis of this well would commence by assuming that the initial reservoir pressure is about 3800 psi (the highest recorded flowing back-pressure). Figure 2 shows the RPI-MDH plot of the Reciprocal Productivity Index ($\Delta\psi/q_s$) versus the log of elapsed time. It shows the interpretation after the initial reservoir pressure has been iterated to convergence. Initially, the graph showed what appeared to be two separate linear clouds of data with about the same slopes, one for the high pressure portion, the other the low pressure portion of the flowback. This is a typical indication that the reservoir pressure is incorrect. Notice that the graph does not show the signature of a new transient when the pressure changed. If the change had induced a new transient, the data points at its start would have fallen below the linear trend. That linear trend is proportional to the reciprocal of the effective permeability-thickness, in exactly the same manner as a Miller-Dyes-Hutchinson or Horner plot are. Its intercept represents the degree of damage or enhancement, called skin.

With the estimated permeability, the values of the "y Intercept" shown in Appendix A are calculated and plotted against either reciprocal rate or rate, as shown in Figures 3 and 4, respectively. That "y Intercept" is the left-hand side of either Eqn. 1 or 2, depending on which plot is being considered. Figure 3 shows the reciprocal rate intercept plot. Examination of Figure 3 shows the final match line for the initial pressure (pseudo-potential). It is clear that there is a "leading-edge" to the "north-west" on the graph. Several points lie further to the "north-west". Those are the same points that lie to the "south-east" on the RPI-MDH plot (Fig. 2). The slope of the match line on Fig. 3 is the initial pseudo-potential and its intercept is proportional to the skin.

Figure 4 shows exactly the same data points as Figure 3, but now plotted against rate as indicated by Eqn. 2, above. Now the slope of the line is proportional to the skin and its intercept is the initial pseudo-potential (pressure). Again, the points to the "north-west" of the line are the same points as those to the "south-east" in Fig. 2. Table 1 shows the comparison of the results. Note that the two graphs do give slightly different pseudo-potential (pressure) results and yet appear to have about the same quality of match on the figures. The more important fact is that the skins independently determined by each of the three methods are in close agreement. These differences actually constitute a very effective means of testing the uniqueness and degree of interdependence of the various parameters.

The Long-Term Production History

Figure 5 shows the production history of a well, which is slightly over two years old. This well is also hydraulically fracture stimulated. Again, the data from Figure 5 have been converted to Reciprocal Productivity Index values to be plotted on the Reciprocal Productivity Index-MDH plot in Fig. 6. Notice the "plateau" effects on Fig. 6 from semi-log times of 2.5 to 3.6, then from 3.7 to 4, and again from 4 until 5.2. That signature is a classic multi-layer response and is consistent with the geologic setting for this reservoir. Numerical simulation of such a system shows that type of drawdown response as well. The results of the interpretation are shown on Table 2.

Figure 7 shows the complete production history in the form of the reciprocal rate intercept graph for the well after the initial pressure, and permeability have been converged. The early time data is to the left. Clearly, the slope decreases with time, which is the depletion signature. Figure 8 shows the left portion of Fig. 7 for the early time initial pressure interpretation. Figures 9 and 10 are the graphs for the full history and early time (right side of Fig. 9) in the rate intercept form. Notice that at the late time, shown on Figs. 7 and 9 respectively for the two methods, the slope presents a direct method to evaluate the degree of pressure depletion. Therefore, this provides a direct method to confirm volumetric-based and "time-to-boundary" drainage area calculations. That comparison is also shown in Table 2.

Conclusions

A practical method has been demonstrated and its theoretical basis shown, which allows the determination of reservoir average pressure during the lift of a producing well, without resorting to build-up testing. The method is an extension to the Reciprocal Productivity Index method to evaluate production histories. Not only can the "Intercept" method be used to evaluate initial reservoir pressure from early time flow tests, it also provides a direct evaluation of reservoir pressure after the outer reservoir boundary is felt (commencement of the depletion phase). There are two drawbacks to the method: a) it requires iteration of the pressure estimate and the effective permeability estimate and b) for some data sets, the pressure estimate is very sensitive to the chosen match line position. Nevertheless, the two interpretation procedures of the Intercept method make the estimation of reservoir pressure possible in routine production data sets. That can be done even in situations where no such evaluation was even possible, previously.

Acknowledgements

I wish to thank several of my clients who believed there might be value in this rather radical analysis procedure. Thank you, Mr. Jim Lawler, Mr. Frank Farnham and Mr. Greg Vigil. You can only guess at the value of your contribution. However, I can say, without reservation, your confidence and willingness to experiment made this possible.

Nomenclature

ψ = Pseudo-potential, m/L^3t, lbm psi/cp ft^3
r = radius, L, ft.
ρ = density, m/L^3, lbm/ft^3
t = time, t, days
S = Skin, dimensionless

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Appendix A: Derivation for the Determination of Reservoir Pressure and Skin

Basic Equation and Variables

The analysis can commence with either the most general form of the pressure transient relationship[4,5,6,7,8]:

$$\Psi_D = \frac{1}{2} E_1\left(\frac{1}{4t_D}\right) + S \qquad \text{(A}$$

or the more restrictive form, which applies after $t_D/r_D^2 > 100$ [1]:

$$\Psi_D = \frac{1}{2}\ln\left(\frac{4t_D}{1.781}\right) + S \qquad \text{(B}$$

where:

$$\Psi_D = \frac{2\pi kh\left(\Psi_i - \Psi_w(t)\right)}{q_s(t)\rho_s},$$

$$t_D = \frac{kt}{\phi\,\mu\,c r^2},$$

$$r_D = \frac{r}{r_w}, \text{ and}$$

S = van Everdingen Skin[6]

Let $P_{DC} = \dfrac{2\pi kh}{\rho_s}$, and $t_{DC} = \dfrac{4k}{1.781\phi\,\mu\,c r^2}$, so that Eqn. B can be re-written as:

$$\frac{\Psi_i - \Psi_w}{q_s} = \frac{1}{2P_{DC}}\ln\left(t_{DC}\,t\right) + \frac{S}{P_{DC}} \qquad \text{(C}$$

Notice that after the permeability has been evaluated, presumably using the RPI-MDH plot, the values of P_{DC} and t_{DC} can be calculated from the determined permeability and given values. Thus, q_s,, $\dfrac{1}{2P_{DC}}\ln\left(t_{DC}\,t\right)$, P_{DC} and ψ_w are known for each time point. Rearrangement of Eqn. C yields:

$$\frac{\Psi_w}{q_s} + \frac{1}{2P_{DC}}\ln\left(t_{DC}\,t\right) = \Psi_i\,\frac{1}{q_s} - \frac{S}{P_{DC}} \qquad \text{(D}$$

to simplify the expression call

$$I = \frac{\Psi_w}{q_s} + \frac{1}{2P_{DC}}\ln\left(t_{DC}\,t\right)$$

so that Eqn. D becomes:

$$I(t) = \Psi_i\,\frac{1}{q_s} - \frac{S}{P_{DC}} \qquad \text{(E}$$

then Eqn. E is clearly a linear equation, in terms of $1/q_s(t)$ and I(t), whose slope is the value of the initial pressure (pseudo-potential, ψ_i) with an intercept which is proportional to the van Everdingen skin (S). Eqn. E can be recast by multiplying through by the rate to yield:

$$I(t)q_s = \Psi_i - \frac{S}{P_{DC}} q_s \qquad \text{(F}$$

which is now a linear equation in term of q_s and I'(t) = I(t) q_s. The slope of this line is the skin and its intercept represents the initial pressure or pseudo-potential.

SI Metric Conversion Factors

cp	x 1.0*	E-03	= Pa * s
ft	x 3.048*	E-01	= m
md	x 9.869 233	E-04	= μm^2
psi	x 6.894 757	E+00	= kPa

*Conversion factor is exact.

Table 1. Flowback Example		
Given Parameters		
Hydrocarbon Porosity (fr.)	.05	
Thickness (feet)	50	
Wellbore Radius (feet)	.5208	
	RPI Analysis	
Match Results		
Effective Permeability (mDs)	.0533	
Drained Area (Acres)	Not in PSS	
Skin	-1.813	
Method	**R**eciprocal **R**ate **I**ntercept	**R**ate **I**ntercept
Skin	-1.831	-1.988
Initial Pressure (PSIA)	6066	5927

Table 2. Long-Term Production History		
Given Parameters		
Hydrocarbon Porosity (fr.)	.0774	
Thickness (feet)	29	
Wellbore Radius (feet)	.5208	
	RPI Analysis	
Match Results		
Effective Permeability (mDs)	.1021	
Drained Area (Acres)	42	
Skin	-5.612	
Method	**R**eciprocal **R**ate **I**ntercept	**R**ate **I**ntercept
Skin	-5.607	-5.615
Initial Pressure (PSIA)	2368	2351
Avg. Pressure (10/99) (PSIA)	749	756

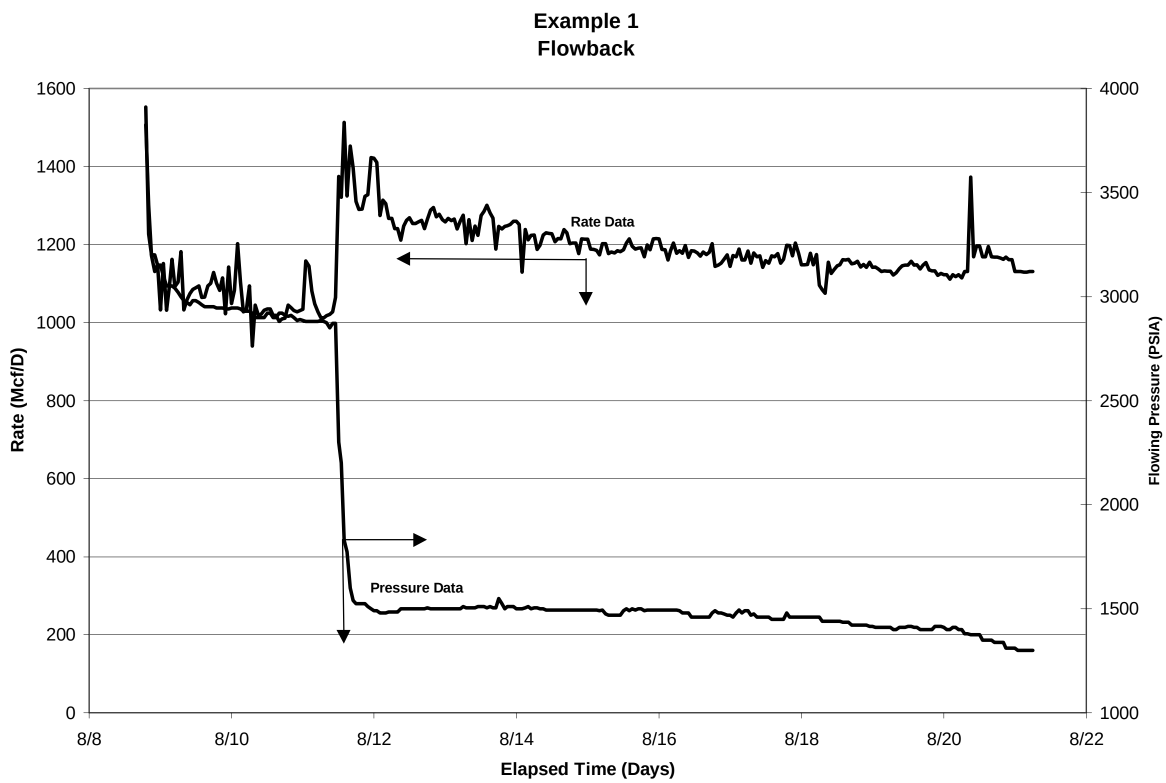

Figure 1. Production History for the Flowback Example.

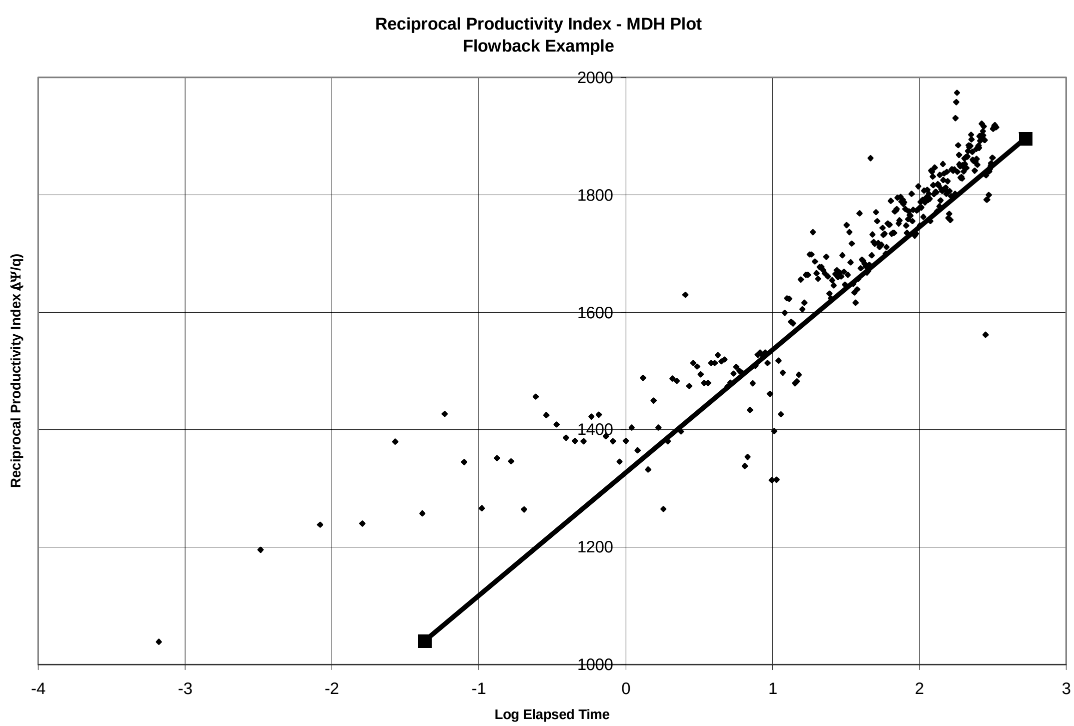

Figure 2. Reciprocal Productivity Index – MDH Plot for the Flowback Example.

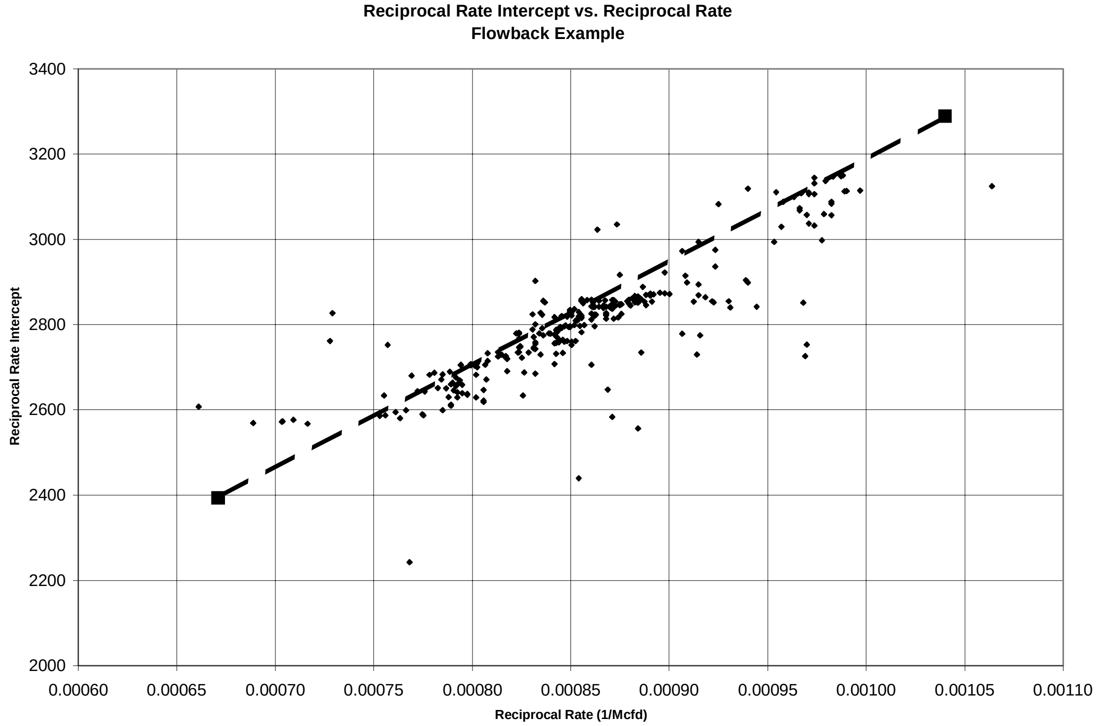

Figure 3. Reciprocal Rate Intercept Graph for the Flowback Example.

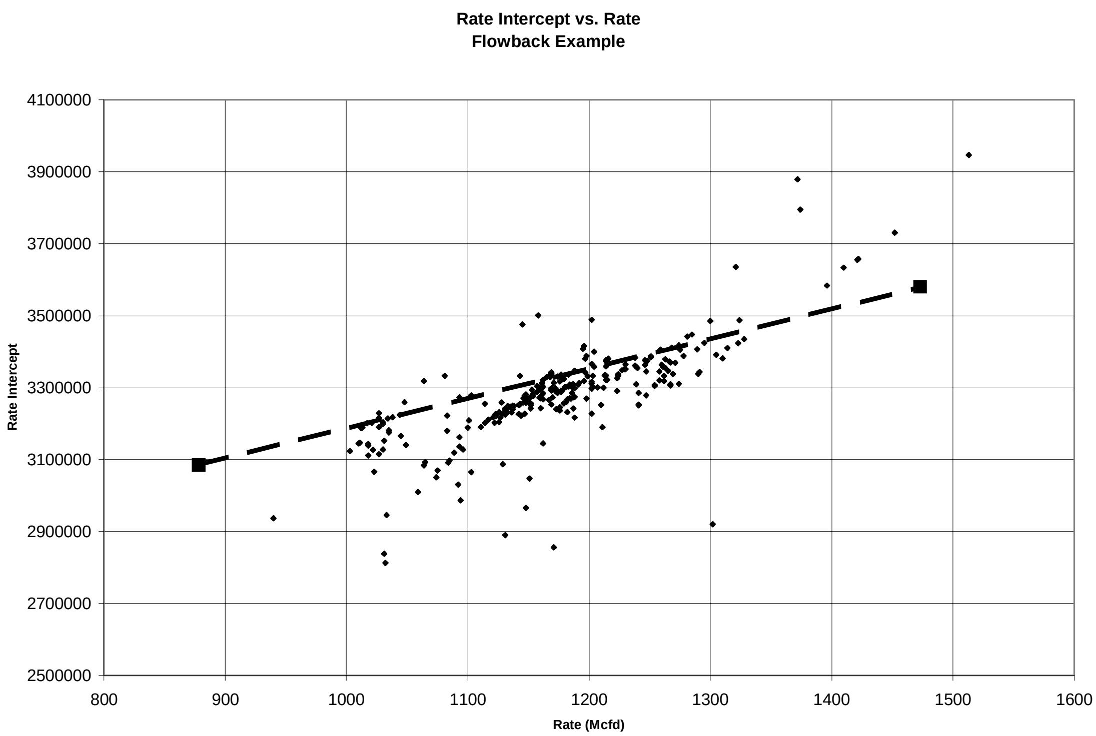

Figure 4. Rate Intercept Graph for the Flowback Example.

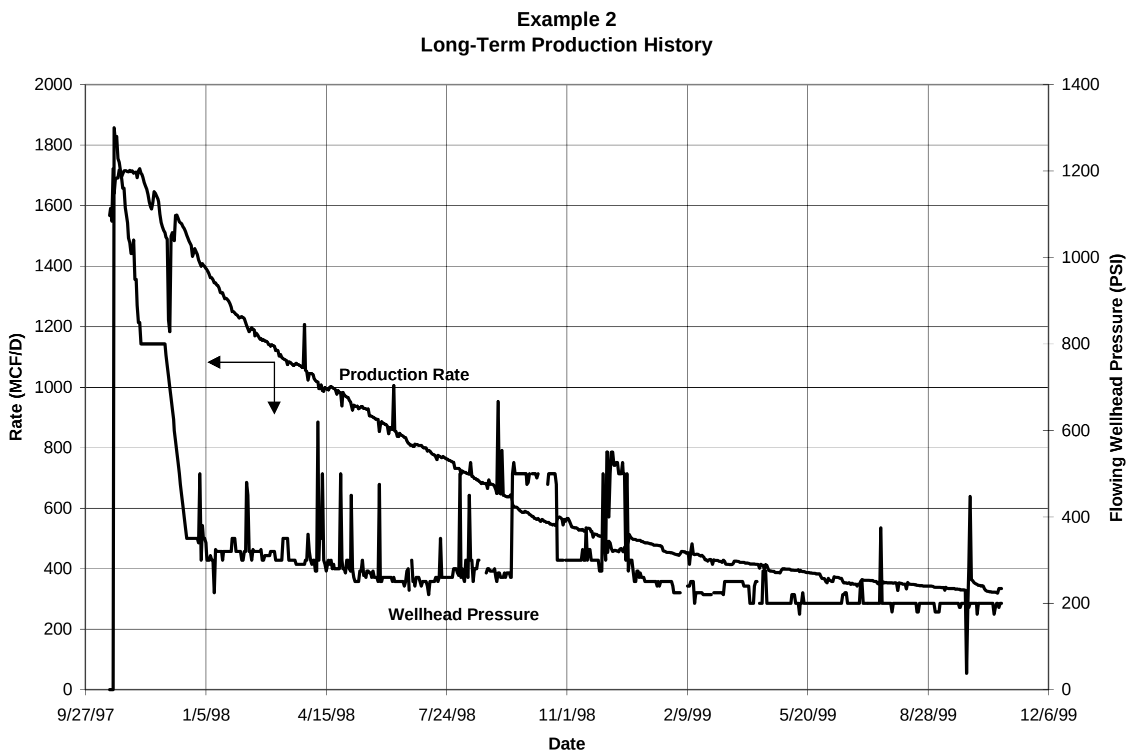

Figure 5. Long-Term Production History Example.

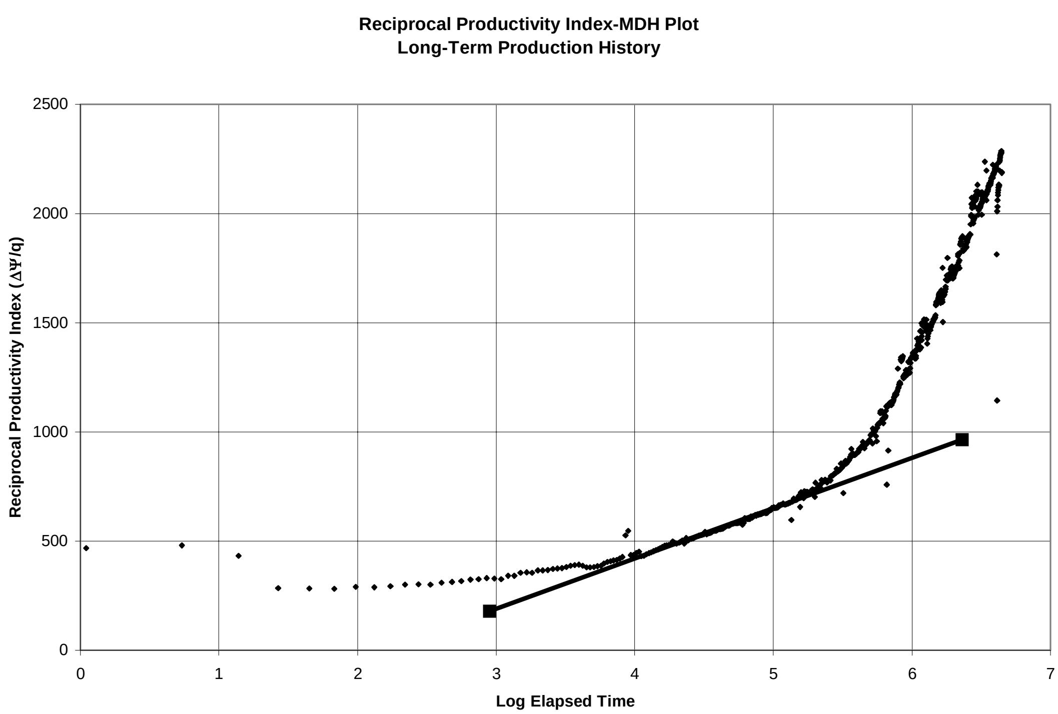

Figure 6. Reciprocal Productivity Index – MDH Plot, Long-Term Production History.

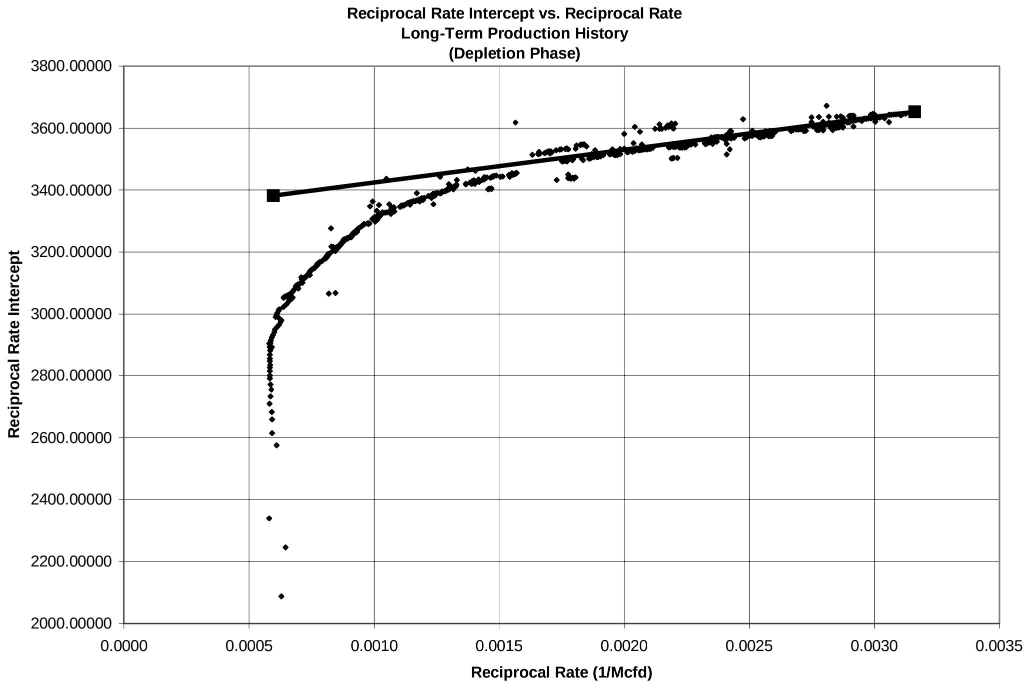

Figure 7. Reciprocal Rate Intercept Graph for complete Long-Term Production History.

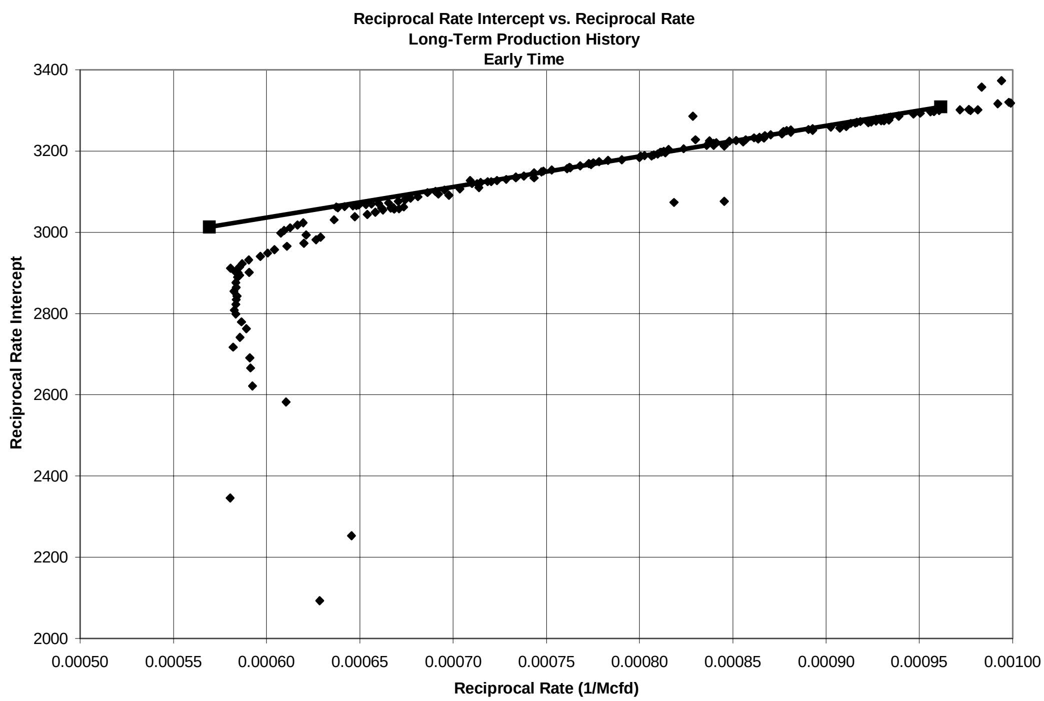

Figure 8. Reciprocal Rate Intercept Graph for early time portion of Long-Term Production History.

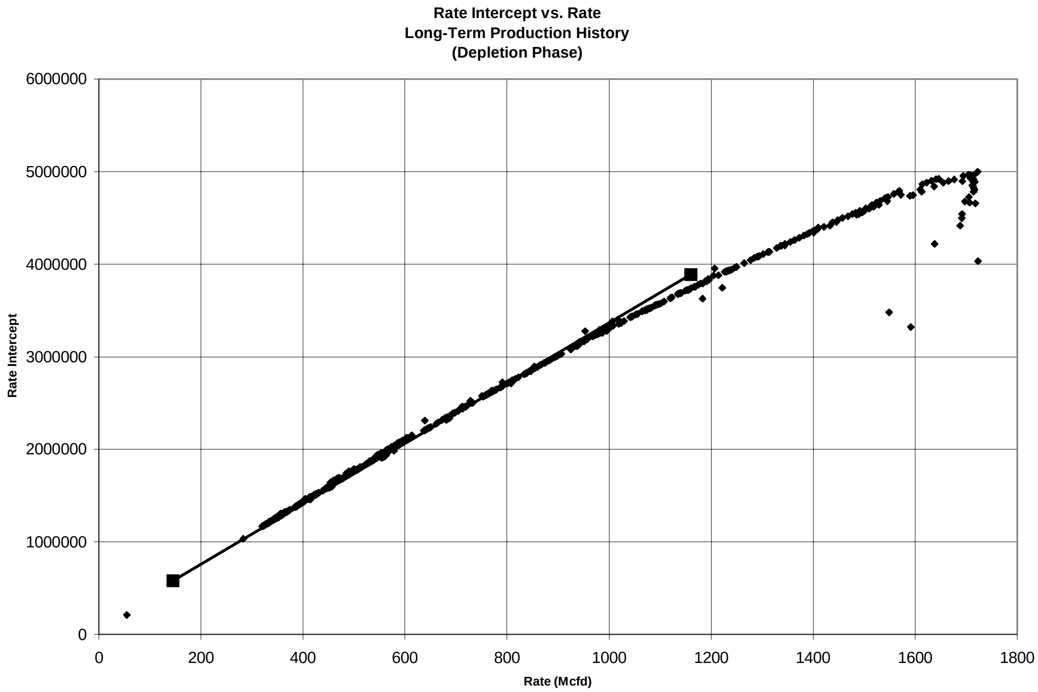

Figure 9. Rate Intercept graph for the Long-Term Production History Example.

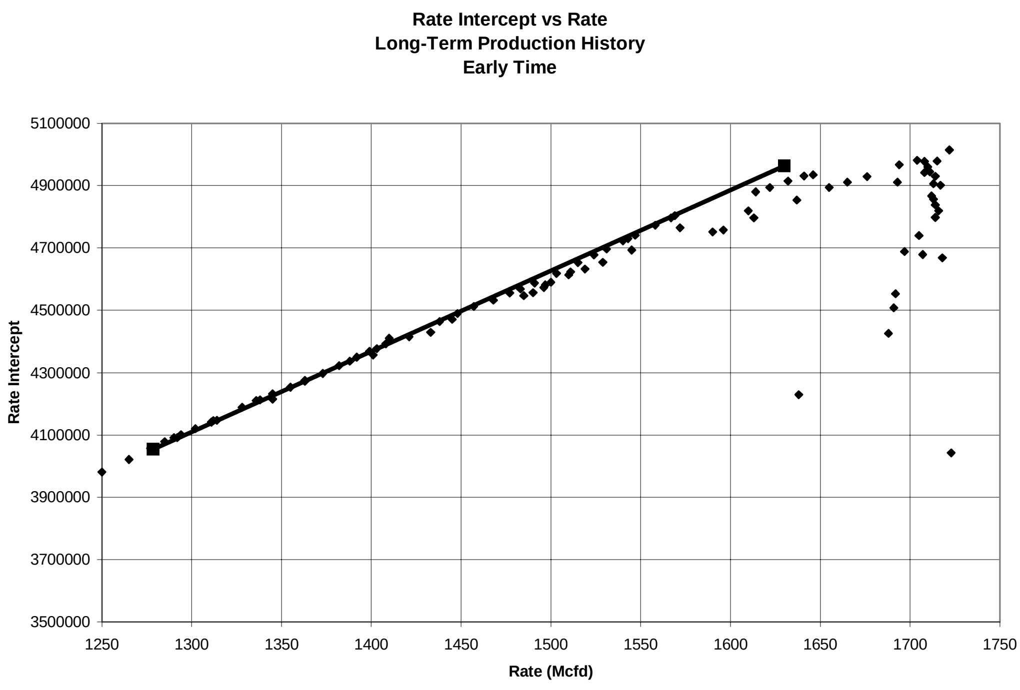

Figure 10. Rate Intercept graph for the early time portion of the Long-Term Production History Example.