AN IMPROVED METHOD FOR PRESSURE BUILDUP ANALYSIS IN BEAM PUMPED WELLS

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Abstract

Pressure buildup analysis has been used for many years to evaluate the performance of wells and estimate the properties of reservoirs. Usually, the application of pressure transient theory to the evaluation of well tests requires that accurate bottomhole pressure measurements be made. In the case of a well producing by beam pumping, the direct measurement of bottomhole pressures is impossible, since the presence of the pump in the tubing physically precludes the use of wireline pressure gages and permanent downhole pressure installations are usually not economically attractive. For this reason, indirect bottomhole pressure measurements are usually made by measuring the annulus pressure at the surface along with the fluid level in the annulus. From these measurements and the fluid densities, the bottomhole pressure may be estimated with an accuracy depending on the accuracy of the estimated fluid properties and the measurement accuracy. This procedure has been criticized, since the pressures being analyzed are not directly measured and the accuracy of the data and estimated fluid properties limits the analysis precision.

This report documents an improved evaluation method for wells producing on beam pumps. Instead of indirectly calculating the bottomhole pressure, the wellbore is modeled and the analysis is performed directly on the measured data. Since both casing pressure and fluid level are measured, the number of data points is essentially doubled over standard well testing and the accuracy of the analysis can be judged by comparison with the actual measured data. In addition, since the casing pressure appears to be mainly affected by wellbore effects, the evaluation accuracy is improved even more than would be expected from statistical considrations alone.

Introduction

In well testing theory, standard practice has been to represent mathematically the flow of fluids in the reservoir, usually using the single phase, radial form of the diffusivity equation. Solutions to this equation are well known and easily computed.[1] Unfortunately, comparison of measured pressure data with theoretical results has shown that the influence of the well itself is significant and must be accounted for in evaluating pressure data. This led to the development of the skin equation[2], wellbore storage[1,3], phase redistribution[4], and wellbore fluid momentum[5]. However, up to this time, nearly all of the well test analysis theories have assumed that the wellbore is open to fluid flow and pressures are measured at the formation face. In many wells this is close to the standard practice, since a bottomhole pressure gage is run into the well and the pressures are measured near the formation.

In beam pumped wells, however, the use of a bottomhole pressure gage is usually infeasible due to mechanical considerations. In addition, since during pressure buildup testing the tubing is closed (assuming that the standing valve does not leak), the assumptions that pressures are measured at the formation face and fluid flow is into the tubing are no longer valid. This has resulted in the use of indirect pressure measurements, with the loss of data accuracy and greater uncertainty in the well test evaluations.

Since it has been estimated that over half of the producing wells in the US are produced by beam pump[6], it would appear to be desirable to accurately evaluate the well performance and reservoir characteristics of these wells. For this reason, an improved evaluation procedure is needed to properly manage such a large number of wells.

In general, for beam pumping wells, the standard well testing equations for flow in the reservoir apply. In addition, since these wells generally produce at relatively low rates, the effect of wellbore momentum can safely be ignored. Since free gas is often produced and sometimes vented up the annulus of the well along with the liquids, which accumulate during a buildup test, we expect that wellbore storage and phase redistribution will dominate the early portion of pressure buildup tests. These effects can be accounted for by the use of standard relations.

Statistical Considerations

The main problem in evaluating well tests from data measured indirectly at the surface is that standard analysis procedures require the estimation of bottomhole pressure. By measuring the surface casing pressure and fluid level in the well, then using the estimated fluid densities to calculate the bottomhole pressure, errors in measurements and estimated fluid properties tend to accumulate, thereby reducing the precision of the bottomhole pressures. If the casing pressure can be measured within 1 psi, the fluid level can be measured within 10 ft, and the fluid density can be estimated within 0.01 psi/ft, the total possible error in the bottomhole pressure estimate for a 5000 ft well with fluid density of 0.35 psi/ft can be on the order of 5 to 6 psi, which is usually considered to be unacceptable for accurate well test analysis.

In statistics, a standard means of improving the accuracy of estimated parameters is to increase the amount of data gathered. For normally distributed data, the accuracy of the estimate of the mean is inversely proportional to the square root of the number of data points gathered. It is also known from sampling theory that our estimates are always improved if we fit a model to the measured data directly, rather than to indirectly estimated data. These considerations mean that to improve the accuracy of well test evaluations, we can

1) use all of the available data (i.e. both casing pressure and fluid level)

2) use a well model that allows us to compare theoretical results directly to the measured casing pressure and fluid level data.

In effect, by regressing against all of the measured data, the number of points sampled is effectively doubled over that used in standard well test analysis. If we neglect differences in the measurement precision, this would improve the standard error of the estimated well and reservoir parameters by some 25-30%. In addition, by directly comparing the predicted casing pressure and fluid level to the measured quantities, we can more easily see how well the data is represented and get a better idea if any observed deviations are due to mechanical, statistical, or modeling errors.

To perform a regression on two data sets simultaneously requires a modification to the normal regression equations. Usually we write a general least squares regression as

$$\text{Minimize } S = \sum_i \left[y_i - f(C_j, t_i)\right]^2$$

where
y_i are measured data
C_j are parameters to be determined,
t_j are independent variables

In the case where we must simultaneously fit two data sets, the equation is modified to

$$\text{Minimize } S = \sum_i \left[y_i - f(C_j,t_i)\right]^2 + \left(\frac{e_y}{e_z}\right)\left[z_i - g(C_j,t_i)\right]^2$$

where
y_i, z_i are measured data
C_j are parameters to be determined,
t_i are independent variables
e_y, e_z are variance factors

For well testing in beam pumped wells, y_i and z_i represent the casing pressure and fluid levels which are measured as a function of time, t_i are the times at which measurements are made, and C_j are the parameters to be estimated from the well test, such as permeability, skin, wellbore storage, etc. In addition, the functions f(x) and g(x) are the relations which predict the casing pressure and fluid levels from theoretical considerations.

Well Model

To model the wellbore in a beam pumped well, we assume that the annulus is open and the tubing is closed at the time that the well is shut-in. This means that the wellbore configuration during drawdown and buildup test periods is different. During a drawdown period, fluids flow into both the tubing and the casing annulus as the well is pumped. During the buildup period, however, the standing valve in the pump is closed, so all fluids which enter the well must go into the casing annulus. We also assume that the casing annulus is closed at the surface and that gas and liquids are segregated in the annulus.

From prior work[4] it is known that the amount of fluid accumulating in the wellbore can be computed from wellbore storage parameters. If we include wellbore phase redistribution, the fluid volume depends directly on the bottomhole pressure and the phase redistribution pressure. Assuming a constant annular cross sectional area, the change in fluid level is proportional to the change in bottomhole pressure, less the amount of phase redistribution, with the constant of proportionality equal to the fluid density. For a closed annulus, the constant of proportionality is somewhat larger, since the effect of the annular gas compression also contributes to the pressure rise. This is expressed as

$$\Delta x_L = \frac{(\Delta p_w - p_\phi)}{C_1}$$

To describe the casing pressure, we note that the bottomhole pressure is equal to the casing pressure plus the weight of gas down to the fluid level and fluid weight from the fluid level to the reference depth. Using this relation, the casing pressure can be represented by

$$\Delta p_c = \Delta p_w - C_1 C_2 \Delta x_L$$

where the additional constant accounts for the effect of the gas compressibility. It has been found that in most cases, C_1/C_2 is equal to the liquid pressure gradient, while C_2 is a number slightly greater than 1. If the annulus were left open during the test, C_1 should exactly equal the liquid pressure gradient and C_2 should be exactly 1.0. Therefore, given the change in bottomhole pressure from a theoretical model, it is possible to calculate the fluid level change and the casing pressure change for a well test. This provides the relations necessary to perform a well test evaluation on the fluid level and casing pressure data directly.

In order to report a meaningful standard deviation, it is necessary to combine both the errors in the casing pressure and in the fluid level. For this reason, the errors in fluid level are multiplied by the fluid gradient, so the total standard deviation can be expressed as a pressure. This is shown as

$$\sigma^2 = \sum \left(\gamma_L \Delta x_L^2 + \Delta p_c^2\right)$$

$$\hat{s} \cong \sqrt{\sigma^2 / n}$$

where σ^2 represents the total variance and n is the total number of data points (fluid level plus casing pressure). Note that $\hat{s}$ is <u>not</u> an unbiased estimator of the standard deviation, since the regression is non-linear, the degrees of freedom are not properly accounted for, and the fluid gradient, γ_L, is estimated. Accounting for the degrees of freedom is not straight forward, since not all of the parameters affect both the casing pressure and fluid level equally.

Examples

To test the procedure outlined above, a computer program was prepared to read the casing pressure and fluid level data, compute the predicted bottomhole pressures from standard well testing equations, compute the casing pressures and fluid levels from the above well model, display the results graphically, and perform a nonlinear regression to adjust the reservoir and wellbore parameters to obtain the best match. The results of the analyses on 3 sets of test data are presented in Table 1 and shown graphically in Figures 1-3. In these examples, it was assumed that the casing pressure is measured at 7 times the precision of the fluid level times the fluid gradient. No attempt was made to screen the data to remove either early or late time data points.

As can be seen, the overall match to the fluid level data appears to be good, while the casing pressure match appears less favorable. Note however that the change in casing pressure is very small, so the effects are magnified on the log-log graphs. In all tests the standard deviation of the casing pressure match is less than 1 psi, while the standard deviation of the fluid level match varies between about 3 and 17 feet. For comparison purposes, analyses were also performed on the bottomhole pressures calculated from the same data, as well as on the fluid level data alone. The results are also presented in Table 1.

Example 1 comprises a set of data where the casing pressure initially dropped slightly. The model result is shown in Figure 1 where it appears that the overall fit is acceptable, with the early and late time drop in the casing pressure trends represented by the model. Note that the permeability and skin estimated from the use of both fluid level and casing pressure data are somewhat lower that those estimated using either fluid level data or computed bottomhole pressures alone.

Example 2, shown in Figure 2, shows a test where the casing pressure shifted by about 1 psi at a time between 1 and 2 hours. In addition, a change in the slope of the fluid level trend is apparent. The reason for these occurrences is not known, but could be due to a change in the density of the fluid entering the well. In spite of this apparent anomaly, the overall fit is quite good with a casing pressure standard deviation less than 0.5 psi and fluid level standard deviation of slightly more than 3 feet. Once again we note that the permeability and skin estimated using both casing pressure and fluid level data are less than those estimated using either fluid level or calculated bottomhole pressure alone.

Example 3 is to be a case where the casing pressure changed relatively little, with a maximum change slightly greater than 1 psi. Regression results seemed to indicate that a phase redistribution did not apply, so the evaluations were done with only wellbore storage. Note that the first part of the fluid level data deviates from the modeled results, perhaps indicating a change in wellbore storage or fluid density in the wellbore. The casing pressure standard deviation is about 0.5 psi, while the fluid level standard deviation was about 7 feet. Once again, the permeability estimated using both the casing pressure and fluid level data is slightly lower than that estimated using either the fluid level data or the estimated bottomhole pressure alone.

Discussion

It is interesting to note that in examples 1 and 2, the wellbore effects (based on the C_D/C_{aD} parameter) are estimated to be higher when either the fluid level or bottomhole pressures are used alone and smaller when both casing pressure and fluid level data are used. Note also that in example 3, where there is no phase redistribution, the storage parameters for all 3 analyses appear to be similar. Based on these observations, it appears that phase redistribution affects the casing pressure data more than the fluid level, so using both the casing pressure and fluid level data allows a better match to the phase redistribution pressure, which in turn allows a better determination of the reservoir and wellbore storage parameters. Since it has already been documented that the combination of fluid level data can be used to estimate the amount of gas influx to the anullus,[7] this appears to be consistent. Since both the fluid level and the bottomhole pressure contains both affects, it is more difficult to fit that data alone.

In addition, the use of fluid level data alone generally seems to yield an equivalent standard deviation similar to that obtained using the calculated bottomhole pressure. Since 1 additional parameter is determined by regression, the standard deviation should be reduced by a small amount, however, since the fluid gradient is determined by regression instead of estimated a priori, the estimates are not amenable to an exact comparison.

The most important result is the smaller standard deviation obtained when using both the casing pressure and fluid level data. Much of the reduction in standard deviation is due to the inclusion of twice as many data points, the small values of casing pressure and the addition of 2 additional fitting parameters in the regression. Again, a direct comparison of estimated bottomhole pressure standard deviations is only qualitatively valid, since the fluid gradients used in calculating the bottomhole pressure is not the same as that determined by regression. It does appear, however, that the casing pressure measurements are important in the analysis, even though the casing pressure generally has a small magnitude in comparison with the fluid level or bottomhole pressure changes, especially when there is evidence of phase redistribution.

Conclusions

Based on evaluating several data sets, it appears that the fluid level and casing pressure calculations as described above work very well, however, in order to completely explain the casing pressure data, it is usually necessary to include a small amount of phase redistribution. It can be shown that in the absence of phase redistribution, the casing pressure should rise monotonically during a buildup test. Actual field data, however, often indicates that the casing pressure decreases late in the test. The model developed here shows that the cause is most likely a small amount of phase redistribution.

1) It is possible to define a simple wellbore mathematical model that applies to beam pumped wells.

2) By using this wellbore model to predict fluid level and casing pressures, it is possible to directly evaluate measured fluid level and casing pressure data during pressure buildup tests.

3) Since the dominant factor in estimating bottomhole pressure from casing pressure and fluid level data is the fluid level, buildup analysis using computed bottomhole pressures is somewhat equivalent to analyzing only the fluid level data and ignoring the measured casing pressure trends during the test.

4) The analysis of well test data using both fluid level and casing pressure data effectively doubles the number of data points used in the analysis at the expense of adding 2 additional parameters to the well model. This results in an analysis that is statistically more accurate than an analysis using the same data to compute bottomhole pressures.

5) It appears, as a result of evaluating several sets of field data, that the exponential form of the phase redistribution function originally proposed by Fair[4] is adequate for beam pumped wells.

6) Based on the evaluation of field data, it appears that the casing pressure in beam pumped wells during pressure buildup testing is more sensitive to the phase redistribution pressure than either the fluid level or computed bottomhole pressure.

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Table 1
Comparison of Analysis Results

Parameter	Example 1			Example 2			Example 3		
Data Used	x_L & p_c	x_L only	Est p_w	x_L & p_c	x_L only	Est p_w	x_L & p_c	x_L only	Est p_w
kh/μ (md-ft/cp)	160.2	170.7	171.4	1848	2222	2289	712.1	716.5	762.1
Skin	4.25	6.22	5.05	11.05	20.69	10.25	5.033	5.076	5.001
S. D. X_L (ft)	17.776	13.205	N/A	3.3937	2.6577	N/A	7.3444	7.3253	N/A
S. D. P_c (psi)	0.7671	N/A	N/A	0.3390	N/A	N/A	0.5118	N/A	N/A
S. D. P_w (psi)	4.891*	5.176*	5.372	1.297*	1.609*	1.204	2.388*	3.330*	3.166
$C_{aD}e^{2S}$	42.852	1225.3	196.4	$1.16x10^{9}$	$3.92x10^{16}$	$2.3x10^{8}$	3407.8	3724.4	3389.1
C_D/C_{aD}	1.018	1.7502	1.818	1.211	5.8247	1.495	N/A	N/A	N/A
$C_{\bullet D}$	0.1221	1.7395	0.953	0.6702	5.993	0.419	N/A	N/A	N/A
C_1	0.3867	0.392	0.426*	0.5313	0.6055	0.4252**	0.4546	0.4547	0.442**
C_2	1.0213	1***	N/A	1.0483	1***	N/A	0.9961	1***	N/A

* Estimated based on value of C_1 and X_L, P_C standard deviations
** Not determined by regression, used in BHP calculation
*** Not determined by regression, since parameter does not affect results.

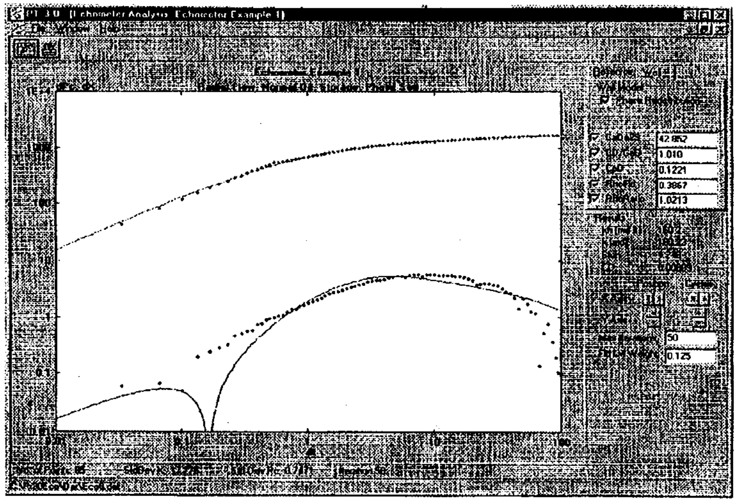

Figure 1 - Example 1

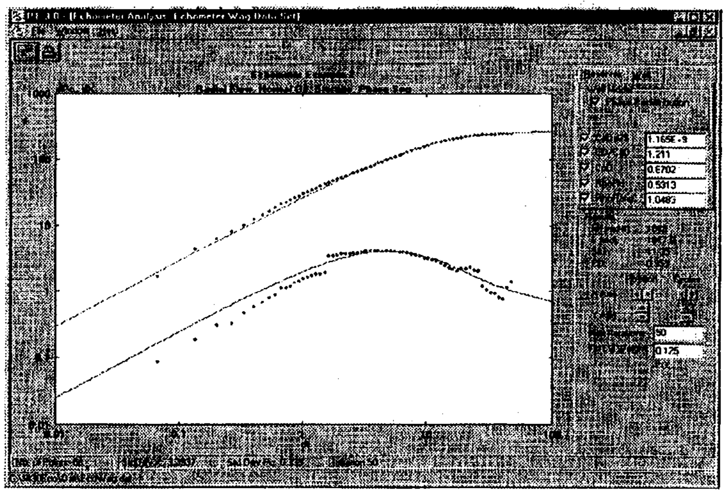

Figure 2 - Example 2

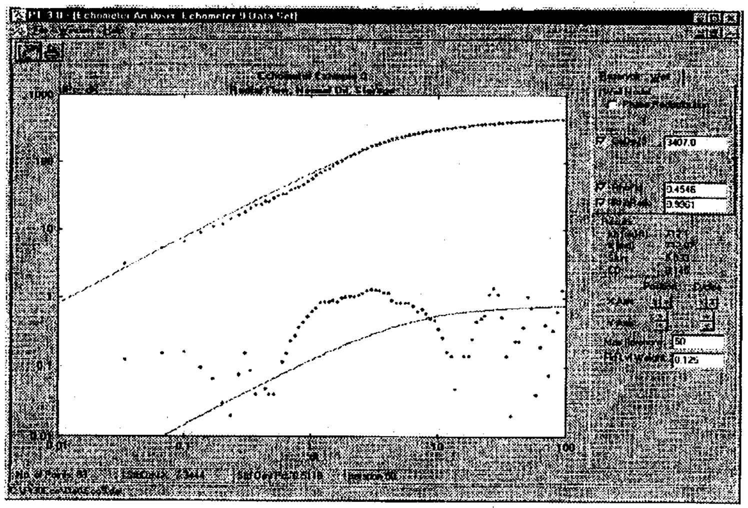

Figure 3 - Example 3