Society of Petroleum Engineers

SPE 49139

Pressure Buildup Analysis With Acoustic Data in Beam-Pumped Wells

Walter B. Fair, Jr., SPE, Interamerican Petroleum Consultants

Abstract

Pressure buildup analysis in beam-pumped wells has suffered from the difficulty in directly measuring pressures at the bottom of the well. Often the only reasonable method for acquiring pressure data in such wells is to combine casing pressure and acoustic liquid level measurements with estimated fluid densities to indirectly estimate the bottomhole pressure[1], which is then analyzed. This procedure introduces errors in the bottomhole pressures, thereby degrading the quality of the analysis. It is also difficult to judge the accuracy of the analyses, since the pressures being evaluated are not directly measured.

This paper presents a simple wellbore model that is applicable to pressure buildup tests in beam-pumped wells. When coupled with the normal wellbore and reservoir fluid flow equations, it is possible to directly model the casing pressures and fluid levels that are measured in acoustic surveys. By adjusting the model parameters to directly match the measured data, an improved evaluation is obtained.

Statistical considerations indicate that, since twice as much data is being used, the results should also be more reliable. In addition, however, it has been found that the casing pressure is extremely sensitive to the wellbore effects, particularly phase redistribution. Since an improved description of the wellbore effects are obtained by matching the casing pressure, improved estimates of the skin and reservoir parameters are also obtained.

This paper presents the theoretical and statistical basis for the improved analysis method as well as the mathematical model. In addition, several examples of actual field analyses are shown. Based on the mathematical model, the effect of errors in the data are also estimated and described.

Introduction

In pressure transient analysis theory, standard practice has been to represent flow within the reservoir using some form of the diffusivity equation. In order to describe flow into the wellbore, the skin equation[2] is usually used, while the wellbore storage equation[3, 4, 5] describes the flow within the wellbore itself. Solutions to this set of equations are well known[3, 4, 5, 6] and can include such effects as fluid after-flow, phase redistribution, temperature changes, and inertial effects in the well. Unfortunately, nearly every theory has assumed that the pressure is measured at the formation face. In flowing and gas-lifted wells a pressure gage is usually lowered into the well on wireline. Under this condition, the pressures are indeed measured in the vicinity of the sand face.

In beam-pumped wells, however, the presence of the pump and rod string usually precludes the direct measurement of bottomhole pressures. Although it is possible to use several types of permanently installed surface readout gages, cost and mechanical considerations usually preclude their use. If the rods and pump are removed from the well, then the difficulty of producing the well or the loss of early time data usually preclude this method of directly gathering bottomhole pressure data.

In such situations, the only practical means for gathering pressure data is to use acoustic measurements to determine the fluid level in the casing. This information is combined with the surface casing pressure and a knowledge of the fluid densities within the wellbore to indirectly estimate the bottomhole pressure, which can then be analyzed using standard methods[1].

Unfortunately, there are several problems with this procedure. First, the bottomhole pressures used in the analyses contain errors due to measurement of casing pressures, measurement of the fluid levels, and due to uncertainties in the fluid densities. These uncertainties can easily lead to errors of several percent in the downhole pressure change, which is generally considered unacceptable. In addition, if there are problems in the data, it is difficult to determine this, since the original data is never matched.

In addition, since 2 measured data items (casing pressure and fluid level) are combined with uncertain fluid densities to compute 1 data item (bottomhole pressure) for use in the analysis, it appears that this procedure effectively discards half of the available information and maximizes any uncertainties in the data.

Background

In pressure transient analysis, it is usually assumed that fluid is produced at a constant rate and that single-phase flow relations can be used[3]. In a beam-pumped well, however, the flow rate is controlled by a subsurface pump and fluid flows into the casing or casing-tubing annulus. Since gas production reduces the efficiency of the pump, gas is normally vented up the annulus while liquids are pumped up the tubing. When the well is shut-in, liquids will flow into the annulus (wellbore storage), however, the fluid column in the annulus is not comprised only of liquids. As shown in Figure 1, the annulus will contain a gaseous liquid column during production and when the well is shut-in, the gas will segregate, causing some amount of phase redistribution.

When data is gathered acoustically, the casing pressure and fluid level are recorded as a function of time[1]. It is straightforward to measure the casing pressure with a transducer or gage, however, the fluid level is usually measured indirectly by introducing a pressure or sound wave into the casing annulus and detecting the reflection or echo from the fluid level[7]. With knowledge of the round trip travel time of the wave and the sonic velocity, the distance to the fluid level can be calculated. Due to variations in the sonic velocity, normally sonic reflections from tubing collars, liners, etc are used to calibrate the procedure and yield greater accuracy.

Although it is beyond the scope of this paper to evaluate the data acquisition, several factors concerning the data should be kept in mind.

Since pressure transducers are generally highly accurate, the casing pressure is normally measured much more accurately than the fluid level. Since all transducers have some amount of temperature sensitivity, however, it is important to be sure that a temperature effect is not being measured, rather than the desired pressure. In most cases with modern temperature compensated equipment, it appears that casing pressures are accurate within about 0.1 – 0.2 psi.

The fluid level determination is more difficult, with potential problems ranging from an inability to detect the fluid level to uncertainties in sonic velocity. When conditions in the well are favorable, quite accurate measurements are possible, with accuracy in the range of 2 – 4 feet, based on experience.

A more insidious problem, however, is the interpretation of the fluid level data. At first thought, it would appear that the fluid level measurement is a direct indication of fluid accumulation in the wellbore (wellbore storage). However, since gas is usually vented up the casing to increase pump efficiency, the fluid level measured is actually the top of a gaseous liquid column, as indicated in Figure 1. In order to determine the bottomhole pressure, the combined densities of the gas and liquid in the fluid column must be accounted for[8]. In addition, since gas will segregate during a buildup test, the amount of gas in the fluid column changes. This will cause a change in fluid level that is independent of the afterflow. In fact, if there is no liquid inflow the measured fluid level would be expected to drop, as indicated in Figure 2. In this case, the casing and bottomhole pressures would rise by an amount given by the phase redistribution pressure.

Other complicating factors that will effect well test evaluation include a relatively large amount of wellbore storage due to flow into the casing-tubing annulus and the presence of a relatively small amount of phase redistribution due to gas in the fluid column at a relatively low pressure.

Therefore it is apparent that in order to model well performance during a pressure buildup test in a beam-pumped well, it will be necessary to understand and model the phenomena of wellbore storage and phase redistribution.

The Wellbore Model

To obtain a wellbore model for a beam-pumped well during pressure buildup, the normal equations for wellbore fluid transport can be used[5]. These are the conservation of mass and the conservation of linear momentum. Since in general the fluid velocities are small in the casing-tubing annulus where most of the flow takes place, the effect of fluid momentum can safely be ignored. Since gas is usually vented from the casing annulus, it is to be expected that phase redistribution could occur. In addition, fluid does not flow to the surface, so the change in fluid volume in the wellbore is equal to the flow rate from the formation. We will also assume that the liquid is incompressible in the wellbore and that the gas is ideal and weightless.

Under these circumstances, the conservation of liquid mass becomes the normal wellbore storage relation with phase redistribution[9].

$$\frac{dV_L}{dt} = q_w = C\left(\frac{dp_w}{dt} - \frac{dp_\phi}{dt}\right)$$

Casing Pressure

If we neglect the gas density, the pressure at the bottom of the well will be directly proportional to the amount of liquid in the wellbore. In other words, it does not matter whether the liquid is at the top, the middle, the bottom, or scattered along the wellbore. Thus, the difference in the bottomhole pressure and the surface casing pressure will be proportional to the liquid volume, independent of the position of the liquid in the wellbore.

$$\frac{dp_w}{dt} - \frac{dp_c}{dt} = \frac{\rho g}{A_w}\frac{dV_L}{dt}$$

Combining these relations gives the equation for the surface casing pressure change in terms of the bottomhole pressure and phase redistribution pressure changes.

$$\frac{dp_c}{dt} = \left(1 - \frac{C\rho g}{A_w}\right)\frac{dp_w}{dt} + \left(\frac{C\rho g}{A_w}\right)\frac{dp_\phi}{dt}$$

Note that for a rising liquid level, which is the major effect in the annulus of a beam-pumped well, the storage would be

$\frac{A_w}{\rho g}$, however, there may be an additional contribution due to compression of the gas in the casing. Therefore denoting $C_L = \frac{A_w}{\rho g}$, we can write the casing pressure equation as

$$\frac{dp_c}{dt} = \left(1 - \frac{C}{C_L}\right)\frac{dp_w}{dt} + \left(\frac{C}{C_L}\right)\frac{dp_\phi}{dt}$$

or in dimensionless form as

$$\frac{dp_{cD}}{dt_D} = \left(1 - \frac{C}{C_L}\right)\frac{dp_{wD}}{dt_D} + \left(\frac{C}{C_L}\right)\frac{dp_{\phi D}}{dt_D}$$

In the general case, C/C_L would depend upon pressure, since the wellbore storage will vary with the compressibility of the gas and liquid in the annulus. In addition, since the gas density has been neglected, the casing pressure change would be slightly less than the pressures given by this relation. At low casing pressures, these assumptions are not severe, but if the casing pressure is high, the effect of the gas density and its variation with pressure should be accounted for more rigorously.

This relation indicates that the casing pressure will rise proportional to the phase redistribution pressure, plus a smaller amount that reflects the change in bottomhole pressure less the pressure head due to the additional liquid in the wellbore. Note that if there is no phase redistribution, the casing pressure will depend only upon the bottomhole pressure change and the storage parameters. Since in general, C_L would be slightly greater than C, the coefficient $(1-C/C_L)$ would be small.

To estimate the value of C/C_L, we can note that the pressure rise due to a A_w volume of fluid influx would be equal ρg pressure units. When the fluid level rises compressing the casing gas, the gas pressure would rise an additional amount given by $p_c x_L/(x_L-1)$ - p_c or $p_c/(x_L-1)$. The total pressure increase would then be the sum of the 2 contributions.

$$\frac{C}{C_L} \approx 1 - \frac{p_c}{p_c + \rho g x_L}$$

For a well with 100 psia casing pressure, an oil density equivalent to 0.35 psi/ft and a fluid level at 1000 ft, C/C_L = 0.778. If the casing pressure is 40 psia and the fluid level at 5000 ft, then C/C_L = 0.977. Since in general casing pressures are low and fluid levels deep, C/C_L will general be slightly less than 1.

At this point we could substitute the casing pressure relation into the normal well testing equations (diffusivity, storage, skin, etc.) and derive a relation for conducting well tests based on surface pressure measurements. The problem with this idea is two-fold. First, since the coefficient $(1-C/C_L)$ is usually very small, the surface pressure is not very sensitive to bottomhole pressure changes, which reflect reservoir performance. A consequence of this behavior is that the casing pressure should be fairly easily matched by considering wellbore effects alone, but that information tells us little about the reservoir performance.

Second, in many cases it is observed that the casing pressure drops at some point during a buildup test. This means that the casing pressure is totally dominated by phase redistribution and in general, the phase redistribution is close to its largest value. Since the phase redistribution pressure derivative is positive, the bottomhole pressure must be decreasing. This corresponds to a “gas hump” which is sometimes observed in buildup tests with bottomhole gages.

Fluid Level

To model the change in fluid level we note that the change in liquid volume in the wellbore is proportional to the change in fluid column height times the liquid volume fraction. This change in liquid volume must agree with the volume change due to storage, which can be represented by integrating the wellbore storage relation.

$$A_w \Delta\left[f_L\left(D - x_L\right)\right] = C\left(\Delta p_w - p_\phi\right)$$

Expanding and rearranging this equation gives a relation for the fluid level change.

$$\Delta x_L = \frac{1}{f_L \rho g}\left(\frac{C}{C_L}\right)\left(\Delta p_w - p_\phi\right) - \left(D - x_{L0}\right)\left(1 - \frac{f_{L0}}{f_L}\right)$$

In the general case, C would vary with the casing pressure as mentioned above and the liquid density may also change as a function of wellbore pressure. Note that the first term accounts for the rise in fluid level due to afterflow and the second term accounts for the decrease in fluid level as gas segregates out of the initial fluid column. In some cases this relation can be used directly, however, if the amount of gas in the fluid column is significant, then the liquid volume fraction will change and must be accounted for.

To estimate the liquid volume fraction we must understand the effect of phase redistribution. As shown in Figure 2, when gas is vented up the annulus, a gaseous fluid column exists. When the well is shut-in, liquid continues to flow due to wellbore storage effects, but the gas also rises and segregates in the annulus. The effect of this gas segregation causes the phase redistribution pressure. Therefore, intuitively we should be able to relate the phase redistribution pressure to the gas volume fraction in the fluid column.

If we consider the gas above the fluid level, the rate of change in the casing pressure will be related to the volume and rate of change of mass. If the gas volume change is relatively small, then the rate of mass influx into the gas above the fluid level is directly related to the rate of pressure change of the gas. Conversely, if mass is accumulating above the fluid level, then it must be leaving the fluid column. As shown by McCoy, et. al.[10], it appears that there is a direct relationship between the rate of mass accumulation above the fluid level and the volume fraction of gas. Since we will normally be interested in cases where the volume fraction of gas is small (less than 30% or so), we assume that

$$f_g \propto A_w x_L \frac{dp_\phi}{dt}$$

Using the exponential form of the phase redistribution pressure function[9], we have the relation that

$$p_\phi = C_\phi \left(1 - e^{-\frac{t}{\alpha}}\right)$$

$$\frac{dp_\phi}{dt} = \frac{C_\phi}{\alpha}\left(1 - \frac{p_\phi}{C_\phi}\right)$$

From this we can infer that the gas volume fraction is directly related to the phase redistribution pressure, which allows us to calculate the liquid volume fraction by difference. At long times $p_\phi = C_\phi$ and the fluid column contains no free gas. At t = 0, when $p_\phi = 0$, the gas volume fraction will be f_{g0}. Considering these constraints gives a relation of the form

$$f_L = 1 - f_g = 1 - f_{g0}\left(1 - \frac{p_\phi}{C_\phi}\right)$$

By combining the liquid volume fraction relation with the fluid level change equation, it is now possible to calculate the change in the observed fluid level during a pressure buildup test. Note that in addition to all of the parameters describing the reservoir, skin, phase redistribution and wellbore storage, 2 additional parameters are needed to describe the initial fluid volume below the fluid level and the initial gas volume fraction.

In dimensionless form, the fluid level relations become

$$x_{LD} = \frac{1}{f_L}\left(\frac{C}{C_L}\right)\left(\Delta p_{wD} - p_{\phi D}\right) - L_{0D}\left(1 - \frac{f_{L0}}{f_L}\right)$$

$$f_L = 1 - f_g = 1 - f_{g0}\left(1 - \frac{p_{\phi D}}{C_{\phi D}}\right)$$

where

$$x_{LD} = \frac{2\pi kh\rho g \Delta x}{qB\mu}$$

$$L_{0D} = \frac{2\pi kh\rho g\left(D - x_{L0}\right)}{qB\mu}$$

Solution of Equations

To use the proposed model to evaluate pressure buildup tests is straightforward. Since these equations describe only flow within the wellbore, we can use any form of the diffusivity equation to compute the bottomhole pressure. Once the bottomhole pressure is known, the casing pressure and fluid level can be computed using the relations given above. Therefore the method is general in terms of reservoir geometry and boundary conditions. The method can be applied to hydraulically fractured wells, dual porosity, dual permeability, composite reservoirs, etc. simply by changing which function is used to represent p_{wD}. In the remainder of this paper, the standard homogeneous, isotropic, radial flow solution to the diffusivity equation with skin, wellbore storage, and phase redistribution will be used[9].

Note that at early times the bottomhole pressure change is linear, being dominated by wellbore storage and phase redistribution. This is described by the equation

$$\frac{dp_w}{dt} = \frac{1}{C} + \frac{dp_\phi}{dt}$$

Substituting the casing pressure relation and rearranging yields

$$\frac{dp_c}{dt} = \frac{1}{C}\left(1 - \frac{C}{C_L}\right) + \frac{dp_\phi}{dt}$$

This shows that the early time casing pressure response is dominated by phase redistribution, as expected. In addition, the slope of the early time pressure change will be slightly different from the apparent storage observe downhole, due to the C/C_L parameter. At long times, when phase redistribution has died out, the change in casing pressure will be directly proportional to the change in bottomhole pressure, but the constant of proportionality will be small since $(1 - C/C_L)$ is generally small, as described above.

The behavior of the fluid level is more complex, as can be seen from the above equations. If the change in the gas volume fraction is small, then the phase redistribution pressure cancels in the equation. In this case the fluid level would change linearly with time, reflecting only the liquid afterflow.

$$\frac{dx_L}{dt} = \frac{1}{\rho g}\left(\frac{1}{C_L}\right)$$

If the gas volume faction changes rapidly enough, the second term in the equation may dominate causing a decrease in the liquid level.

At long times, the gas volume fraction would be constant and the phase redistribution would be negligible, so the fluid level change would reflect bottomhole pressure changes alone.

Statistical Considerations[11]

The normal method for fitting a relation to measured data assumes that there exists a relation of the form $y = \hat{y}(C_i, x_i)$ where y is the dependent variable, x_i are independent variables and C_i are the constants to be determined by the regression. For well test analysis, the independent variable is normally the measured bottomhole pressure, the independent variable is time, and the constants are the parameters that determine the pressure response (i.e. storage, skin, permeability, etc.). In this case the normal least squares regression problem can be stated as

$$Minimize\ S = \frac{\sum_j \left[p_{wj} - \hat{p}_w\left(C_i, t_j\right)\right]^2}{\sigma_{p_w}^2}$$

and an estimate of the standard deviation of the regression is given by

$$s = \sqrt{\frac{\sum_j \left[p_{wj} - \hat{p}_w\left(C_i, t_j\right)\right]^2}{n_j - n_i - 1}}$$

When we have data comprised of both casing pressures and fluid levels, however, it is necessary to modify the least squares formulation so that both are matched at the same time. Thus the modified least squares problem can be stated as

$$Minimize\ S = \frac{\sum_j \left[p_{cj} - \hat{p}_c\left(C_i, t_j\right)\right]^2}{\sigma_{p_c}^2} + \frac{\sum_k \left[x_{Lk} - \hat{x}_L\left(C_i, t_k\right)\right]^2}{\sigma_{x_L}^2}$$

or similarly

$$Minimize\ S = (1-w)\sum_j \left[p_{cj} - \hat{p}_c\left(C_i, t_j\right)\right]^2 + w\sum_k \left[x_{Lk} - \hat{x}_L\left(C_i, t_k\right)\right]^2$$

where there are j observations of casing pressure, k observations of fluid level, the σ^2 represent the variance of the measurements, and w is the relative statistical weight of the fluid level data, which will be between 0 and 1. In this case there are 2 related estimates of standard deviation which are given by: (Note that n_i is the same as above, so the relations have 2 and 3 more coefficients, respectively.)

$$s_{p_c} = \sqrt{\frac{\sum_j \left[p_{cj} - \hat{p}_c\left(C_i, t_j\right)\right]^2}{n_j - n_i - 2}}$$

$$s_{x_L} = \sqrt{\frac{\sum_k \left[x_{Lk} - \hat{x}_L\left(C_i, t_k\right)\right]^2}{n_k - n_i - 3}}$$

Note that if equal numbers of casing pressures and fluid levels are measured (as is usually the case), then $n_k = n_j$ and the denominator is about twice as large as the denominator in the regression equation for the pressure formulation. There is a trade off, since there may be 3 additional terms to estimate in the regression, so the improvement in the standard deviation estimate would be approximately $\sqrt{\frac{n_j - n_i - 1}{2n_j - n_i - 4}} \approx \sqrt{\frac{1}{2}}$, assuming that a relatively large number of points are used in the regression. This represents about a 30% improvement in the estimated standard deviation, if the estimates were unbiased. Unfortunately, the estimates are not unbiased, since the casing pressure and fluid level are both estimated at the same time.

In general we are interested in the accuracy of the parameters (permeability, skin, etc.) rather than the standard deviation of the regression. Due to the added complexity and the addition of statistical bias, the estimation of accuracy is not straightforward. However, as long as there are more than a few data points, the standard error of the estimated parameters will be less than if estimated using half of the number of data points.

Note that this discussion assumes that we know the reservoir and wellbore model and only need to estimate the parameters by regression. If we do not know the model or do not have the correct model, then the estimates, statistical or otherwise, are meaningless.

There is, however, an additional benefit that is important, but difficult to quantify. Since we previously noted that the casing pressure is relatively insensitive to the reservoir parameters and very sensitive to the wellbore parameters, matching the casing pressure allows us to make a good estimate of the wellbore behavior. If we know the wellbore behavior accurately, then the remaining reservoir parameters can also be estimated with more precision.

This is somewhat equivalent to defining the wellbore behavior and using deconvolution to determine the reservoir response. The advantage of the method proposed here is that both the wellbore and the reservoir effects are determined by regression. This approach does not magnify errors in the deconvolution caused by small errors in the wellbore estimates.

Testing and Analysis Procedure

Given the mathematical description of the well model derived here, it would appear that a pressure buildup test in a pumping well could simply be evaluated by fitting the model to casing pressure and fluid level data. Unfortunately, from a practical standpoint that cannot be easily done. Since there are a large number of parameters to match in the general case, nonlinear regression analysis would be slow. In addition, the presence of errors in the data may cause the regression to wander off into unphysical areas trying to match minor variations in casing pressure and fluid levels. For this reason it is important that a synergistic approach to well test evaluation be used.

In general, some information on the well mechanical configuration and fluid properties is available. Given some rudimentary information on fluid densities and annular area, the C/C_L parameter is easily estimated. In addition, the perforation depth is general known, so the initial fluid column height can also be determined a priori. This reduces the number of parameters to be matched by 2. Furthermore, the correlation of McCoy, et. al.[10] for estimating the initial gas volume fraction appears to work very well in obtaining an initial estimate.

A further consideration when trying to interpret analysis results is that we have assumed that the observed phase redistribution is indeed phase redistribution. As shown in an earlier paper[5], the term that represents phase redistribution is actually the pressure change at constant mass. It was pointed out that a very similar effect can be caused by temperature or phase changes within the wellbore, as well as the segregation of the liquid and gas phases. Since the well testing equations are formulated in terms of liquid flow, the phase redistribution pressure actually represents any change in pressure at constant *liquid* mass. Since we usually have gas flow in addition to liquid flow, flow of the gas may cause an additional pressure change that is not directly associated with phase segregation. It appears that the formulation presented in this paper usually represents these effects adequately, but the parameters estimated for phase redistribution may be different than expected based on phase redistribution alone.

We can also take advantage of the sensitivity of the casing pressure to the wellbore storage and phase redistribution parameters. It has been found that by giving greater weight to the casing pressure, the phase redistribution and storage parameters in a nonlinear regression converge very quickly. After these parameters have been estimated, a second regression stage is performed where the fluid level data is given more weight. This allows the reservoir parameters to converge faster. Finally, once acceptable casing pressure and fluid level behavior is obtained from the model, a final regression is made using weights based on the actual data measurement precision. This procedure ensures that reasonable values for the parameters are obtained and the overall test performance is well matched. Unfortunately, no reliable method for automating this procedure has been found.

Also, in light of the mathematical model several factors should be considered in conducting an acoustical pressure buildup test. Before conducting a test, the wellbore integrity should be ensured. This includes determining that both the casing valve and the pump seats are not leaking, since either of these effects would distort the well performance.

It has also been recommended in the past that the casing pressure should be allowed to build before conducting either a buildup test or using acoustic data to evaluate well inflow performance[1]. This procedure reduces the gas inflow into the casing-tubing annulus and has the effect of reducing the amount of phase redistribution observed during the buildup test. By reducing the effect of phase redistribution, the observation of reservoir related parameters is enhanced. Since we have assumed that the phase redistribution pressure is exponential, the mathematical model is still valid.

Also the purpose of the test should be kept in mind. Since beam-pumped wells generally operate at low pressures and the amount of wellbore storage is generally large, any affects occurring at early times will not generally be observable. These may include hydraulic fractures, which often seem to show up as a small or negative skin in the evaluation. At long times, the rate of pressure change is generally small and boundary affects may be masked by measurement accuracy to a larger extent than if bottomhole gages were used.

Examples

Example 1

This well illustrates the use of the proposed method when there are problems in the acoustic data. As shown in Figure 3, the calculated bottomhole pressure change appears to be noisy as seen in the derivative plot. Attempts to fit this data resulted in problems due to this noise. The most reasonable match appeared to be with a very high skin and a large amount of storage, which did not seem right in view of the well performance.

The raw acoustic data is shown in Figure 4, where a strange cyclic behavior is evident in the casing pressure, which actually changed very little. Since the casing pressure cycles on about a 24-hour period, it is thought that the pressure transducer was not temperature compensated, so the data shows the daily temperature variations and not the casing pressure variations. Evaluation of the measurements indicates that the casing pressure was indeed quite low and the fluid level measurements should be reasonably accurate.

Using these raw data a regression was performed using the well model described in this paper. The weighting factor for the regression was chosen at 0.5 so 1 psi casing pressure change has the same weight as about 6-7 ft of fluid level change. This forces the predicted casing pressure to honor the general pressure level while allowing the fluid level data to control the main part of the match. The resulting match is shown in Figure 5, with C/C_L = 0.996, and no phase redistribution. As can be seen, the total casing pressure changes by only about 1 psi and remains flat over most of the test. The standard deviations of the regression are about 0.54 psi and 5.4 ft for the casing pressure and fluid level, respectively or about 3 times the estimated measurement accuracy.

Example 2

The second example bottomhole pressure data are shown in Figure 6 with the raw acoustic data in Figure 7. Again, the data appears to be fairly noisy and the derivative is nearly useless. Attempts to match the pressure data resulted in a very indeterminate analysis. By trading off storage, skin and permeability, nearly any interpretation could be made.

The match to the casing pressure and fluid level is shown in Figure 8. Note that the fluid level data has quite a bit of scatter, however, the match seemed to have no problem representing a reasonable trend through the data. The satandard deviation of the casing pressure match was about 1.5 psi, which the fluid level was matched to about 4.5 ft.

Example 3

The third example shows what can happen when a beam pump is operated efficiently. In this well, the fluid level was very close to the pump and the pump was set very near the perforations. The estimated bottomhole pressure data are shown in Figure 9. Note that the data does not look too bad. There is a little scatter in the data, but a readily recognizable trend is apparent, even in the calculated derivatives. The acoustic data, shown in Figure 10, however, shows somewhat of an oddity. First, the fluid level rises, as expected, and then drops, indicating that there is a significant phase redistribution effect in the well. However, at about 7 hours, the fluid level seems to abruptly stabilize somewhat and fluctuates around 2390 ft. What has happened, is that the fluid has all been pushed back into the formation and the acoustic fluid level is varying somewhat randomly due to minor fluctuations and noise. Obviously this violates all of the assumptions in well test theory, so evaluation of this data is risky.

The data before about 7 hours, however, appears to be reasonable. During this time the fluid level was rising and fallling, so we would expect our model to apply. Figure 11 shows the results of matching the first 7 hours of data

Conclusions

It has been shown that it is possible to derive a wellbore model applicable to pressure buildup analysis in beam-pumped wells. As a result of the mathematical model, an improved procedure for analyzing such tests has been proposed and tested. The new method offers several important features, including the ability to compare measured data directly to the mathematical model and improved statistical accuracy:

In addition, the theoretical basis presented here shows that there are also some subtle but important implications. First, the model is not limited to beam-pumped wells, but a similar wellbore model can be developed for a general wellbore. In particular, the casing pressure equation, perhaps with the inclusion of fluid compressibility effects, can be used in gas lifted or flowing wells. Thus, by measuring bottomhole and surface pressures simultaneously, improved accuracy in the interpretation of nearly all well tests could be expected.

Second, it has been pointed out that the phase redistribution pressure is actually a pressure change at constant wellbore mass[5], but in conjunction with the development of the model presented in this paper, it is obvious that it represents the pressure change at constant mass of the primary flowing fluid. Recognition of this opens the possibility of coupling the flow equations for multi-phase flow through the constant mass pressure change to describe pressure changes within the wellbore. The detailed implications of this observation still need to be evaluated and developed. Of course, if fluids in the reservoir are flowing together, it will also be necessary to couple the reservoir flow equations[6].

The main points of this paper are:

- It is possible to directly evaluate the data actually measured in acoustic pressure buildup tests.
- The use of both casing pressure and fluid level data effectively doubles the number of data points used in the analysis.
- Since the surface casing pressure is very sensitive to wellbore effects, the wellbore effects are more accurately estimated. As a result the reservoir parameters can also be estimated with greater precision.
- Since several of the additional parameters required for pressure buildup analysis are generally available from well mechanical information, in practice the number of parameters matched is not significantly increased.
- Tto accurately evaluate well tests in beam-pumped wells, it is necessary to account for the effects of phase redistribution.
- Based on the model presented here and the analysis of actual field data, it appears that the exponential form for the phase redistribution pressure is still reasonable.
- It appears that well tests in general could be improved if surface pressures, as well as bottomhole pressures, were measured.
- As a result of this work, it can be concluded that the phenomena of phase redistribution must be viewed in a much more general context. It represents not only the segregation of phases within the wellbore and pressure changes at constant wellbore mass, but also the pressure effects due to the influx of other phases as well.

In addition, there is an important area of uncertainty in the proposed model. Since the liquid level calculation depends on the description of the gas volume fraction change during phase segregation and no accurate data measuring phase segregation phenomena could be found, an empirical procedure was used which appears to be adequate. The proposed model could be improved if a more rigorous formulation for both the phase redistribution pressure and the gas volume fraction in the fluid column were available.

Nomenclature

A_w	*Wellbore cross sectional area*
C	*Wellbore storage coefficient*
C_ϕ	*Phase redistribution coefficient*
C_L	*Liquid storage coefficient*
D	*Perforation depth*
f_g	*Gas volume fraction*
f_L	*Liquids volume fraction*
g	*Gravitational constant*
h	*Formation thickness*
k	*Formation permeability*
n	*Number of measurements*
p_c	*Casing pressure*
p_ϕ	*Phase redistribution pressure*
p_w	*Bottomhole pressure*
q_w	*Bottomhole flow rate*
S	*Least squares function*
S	*Standard deviation*
t	*time*
V_L	*Liquid volume*
w	*Statistical weighting factor*
x_L	*Fluid level from surface*
α	*Phase redistribution time constant*
ρ	*Liquid density*
σ^2	*Statistical variance*

Acknowledgements

The author thanks Dr. A. L Podio of The University of Texas at Austin for enlightening discussions on well testing procedures and modeling the fluid level, as well as J. N. McCoy and Dieter Becker of Echometer for providing test data and information on data measurement methods and accuracy. Thanks also to Nautilus Exploration for providing data and well information used to calibrate and test the

mathematical model.

References

1. McCoy, J. N., A. L. Podio, and Dieter Becker, “Pressure Transient Digital Data Acquisition and Analysis From Acoustic Echometric Surveys in Pumping Wells”, SPE 23890 presented at the SPE Permian Basin Oil and Gas recovery Conference, Midland, Texas, 1992,
2. Van Everdingen, A. F., The Skin Effect and Its Influence on the Productive Capacity of a Well,” Trans. AIME (1953) 198, 171-176.
3. Van Everdingen, A. F. and W. Hurst, “The Application of the Laplace Transformation to Flow Problems in Reservoirs,” Trans. AIME (1949) 186, 305-324.
4. Agarwal, R. G., Rafi Al-Hussainy and H. J. Ramey, Jr., “An Investigation of Well Bore Storage and Skin Effect in Unsteady Liquid Flow: I. Analytical Treatment,” SPEJ (Sept 1970) 279-290; Trans. AIME 249.
5. Fair, Walter B. Jr., “Generalized Wellbore Effects in Pressure Transient Testing,” SPE Formation Evaluation (June 1996).
6. Raghavan, Rajagopal, Well Test Analysis, Prentice Hall, Englewood Cliffs, N. J., 1993.
7. McCoy, J. N., “Measuring Liquid Level with Acoustic Velocity,” Petroleum Engineer (July 1975).
8. McCoy, J. N., “Determining Producing Bottomhole Pressures in Wells Having Gaseous Columns,” JPT (Jan. 1978).
9. Fair, Walter B. Jr., “Pressure Buildup Analysis With Wellbore Phase Redistribution,” SPEJ (April 1981).
10. McCoy, J. N, A. L. Podio and K. L. Huddleston, “Acoustic Determination of Flowing Bottomhole Pressure”, SPE Formation Evaluation (Sept. 1188).
11. Draper, Norman and Harry Smith, Applied Regression Analysis, John Wiley and Sons, Inc., New York, 1966.

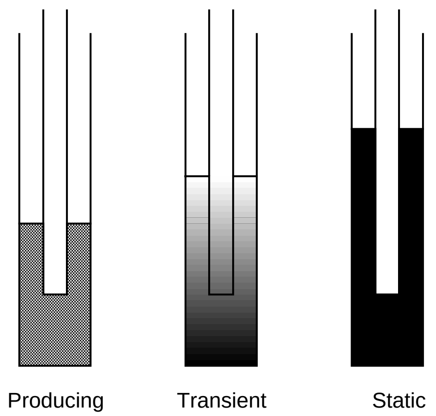

Figure 1. Annular fluids in a beam-pumped well

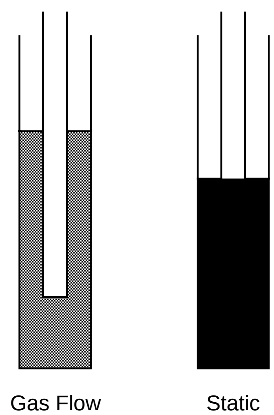

Figure 2. Fluid level change with no liquid inflow

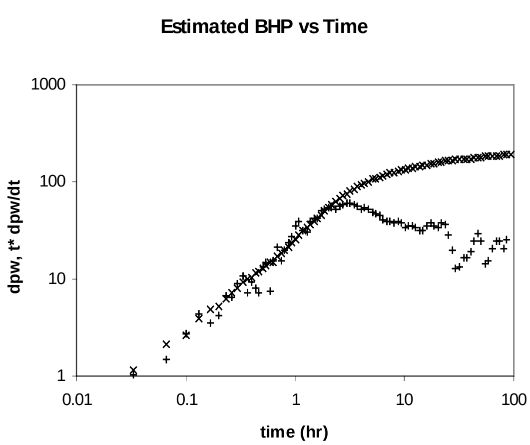

Figure 3. Estimated BHP data for Example 1

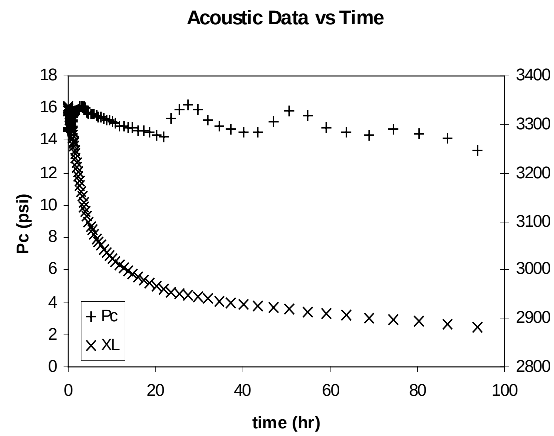

Figure 4. Raw acoustic buildup data for Example 1

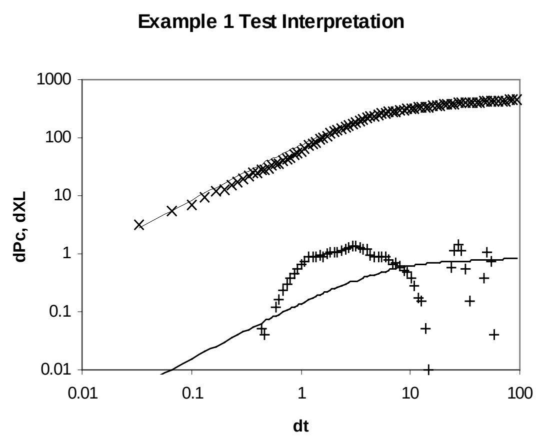

Figure 5. Match for Example 1 acoustic well test data

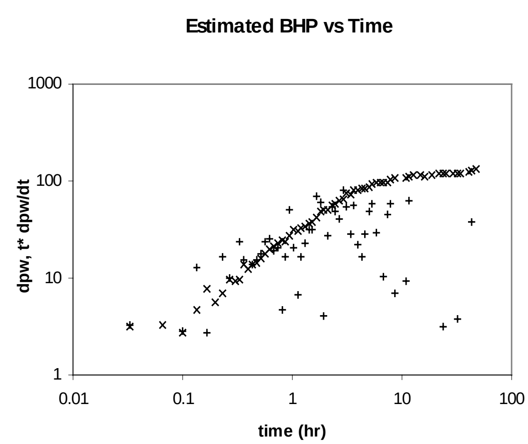

Figure 6. Estimated BHP data for Example 2

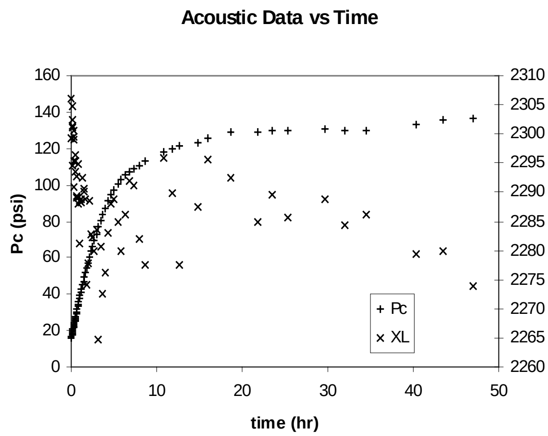

Figure 7. Raw acoustic buildup data for Example 2

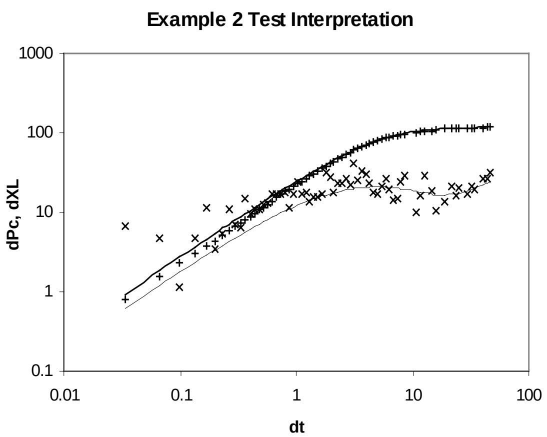

Figure 8. Match for Example 2 acoustic well test data

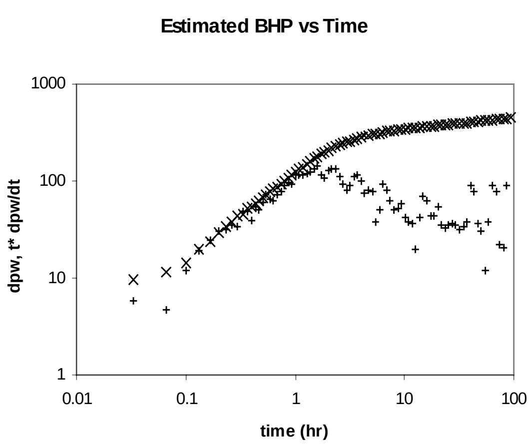

Figure 9. Estimated BHP data for Example 3

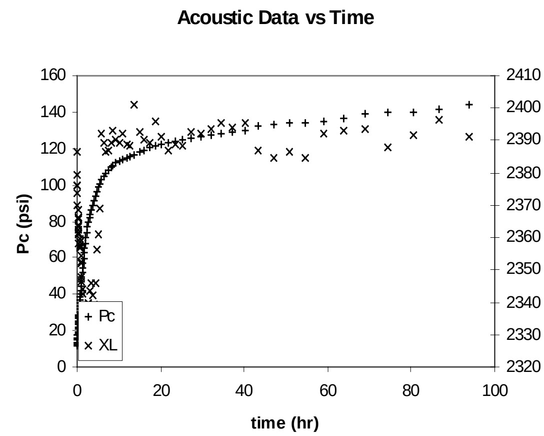

Figure 10. Raw acoustic buildup data for Example 3

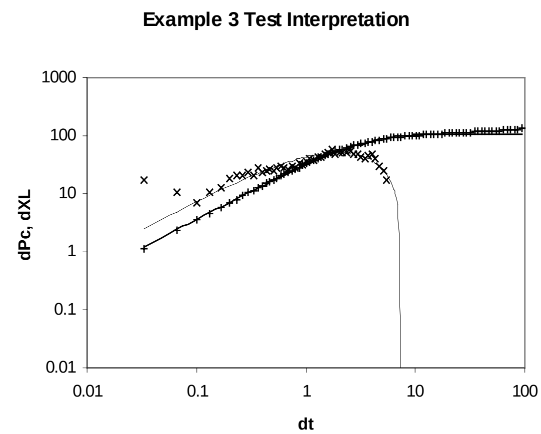

Figure 11. Match for Example 3 acoustic well test data