COMBINING TRANSIENT RATE AND PRESSURE DATA WITH PRODUCTION LOGGING FOR ENHANCED WELL TEST ANALYSIS **

C. F. Bingle

Schlumberger Well Services

ABSTRACT

Many gas wells drilled today are completed over 100 ft or more of gross pay interval to maximize deliverability, reserves, and revenue. Formation permeability of these wells is usually very low (less than 1 md). Use of conventional transient pressure analysis to understand formation properties is seldom done because of time (many days or even weeks) needed to acquire correct answers. Knowledge of producing zones and their respective amounts are rarely studied. Such limited knowledge concerning formation properties (permeability, pressure, drive mechanism, etc.) and flow profiles can often lead to poor reservoir management throughout the life of the field and eventually leave many thousands of dollars of reserves behind.

Combining production logging with the transient rate and pressure analysis (TRAP*) allows one to identify the wellbore's flow profile and formation flow properties such as permeability, average reservoir pressure, and skin factor (near wellbore and total skin) in less than one day. Such combination testing can identify flow regime, drive mechanism, coning or fingering problems, unusual pressure or zonal depletion, presence of crossflow, scale, or plugged perforations; all of which if identified in time, can be used positively to maximize production and revenue.

The TRAP technique uses the production logging tool. First, up and down passes over the perforated interval are made prior to the well test to identify the well's flow profile. Production logging passes made at varying flow rates can further be used to identify the reservoir flow behavior, and the associated reason. For the well test part, the TRAP technique incorporates measuring changing rate data with the corresponding pressure data during a buildup, drawdown, or multirate test. Using the principle of superposition (continual integral), it eliminates wellbore storage problems and identifies formation flow properties in a very short time frame.

The TRAP technique is illustrated through the analysis of two deep gas well tests.

* Mark of Schlumberger

INTRODUCTION

Many of today's drill wells and workovers are justified by what other wells in the area have produced. They are usually completed similarly and predicted to produce similarly as offset wells. It is only when these wells fail to perform "as expected" that concern arises as to the effectiveness of the completion or quality of the reservoir. This type of drilling, completion, and workover operation leads to several questions. One, how is "as expected" defined? If it is not known why a certain well is producing at a certain rate, then how can another well be compared to it? Second, if only failures are evaluated, what is defined as "good"? In other words, what condition is trying to be obtained to maximize this well's worth? Third, if "good" wells are only evaluated when they become poor, how is the cause determined?

Unfortunately, many gas wells and gas fields are rarely studied from beginning to end. Wells producing at economic rates are ususally left alone. Wells producing below economic rates are usually not offset. Not knowing why one scenario happens over the other (assuming geologic descriptions to be consistent), leaves one without any choice. However, knowing why a well or formation is good, or why it is bad, can lead to solutions and positive results; maximum reservoir development and minimum unnecessary drilling and workover costs.

This paper discusses the advantages of combining transient rate and pressure data with production logging to enhance well test analysis and thus enable the engineer to make better reservoir management decisions. Complete reservoir description, pressure transient work and production logging should be done on a new well to understand initial reservoir conditions. Continual testing throughout the life of the well can define "expected" conditions, identify necessary workovers, and pinpoint potential problems before they happen.

Transient rate and pressure analysis has been well documented by Ahmed, Kucuk, and Ayestaran[1], Meunier et al,[2] Guillot and Horne,[3] and others.[4 8] Although field data are limited, recent work by Ahmed[9] shows many examples of improved accuracy in calculating reservoir flow properties with downhole transient rate and pressure data. Use of downhole transient rate data with pressure data eliminates wellbore storage problems and allows accurate interpretation of reservoir permeability, pressure, and skin damage during the early time period. This ability to acquire quick and accurate data enhances the effectiveness of gas well testing, since many wells may take weeks or even months to properly evaluate using pressure data alone. A further enhancement, as discussed in this paper, is the ability to combine production logging information with more accurate reservoir flow properties in describing the current dynamic reservoir behavior. This information can be further used in predicting and preparing for future reservoir conditions.

This paper will first discuss the test procedure to acquire the data, the theory involved in transient rate and pressure analysis, and finally, two field examples employing the TRAP technique.

TEST PROCEDURE

The test procedure for incorporating the TRAP technique is very flexible depending on the information desired and the current wellbore conditions. Following is a list of procedures that can be used for various types of tests.

The simplest procedure would be for a normal buildup test. First, the production logging tool would be lowered into the wellbore while the well is still flowing. Production logging passes (up and down) would then be made over the producing interval recording temperature, fluid density, pressure, and flow rate (from fullbore spinner). Interpretation of these measurements will identify fluid entry points (or exit points if crossflowing), fluid type, and volume.

The production logging tool will then be placed just above the zone of interest (Fig. 1). Bottomhole flowing pressure and rate will be recorded with time. Next, the well will be shutin at the surface. At the instant of shutin, the production logging tool will begin measuring the corresponding pressure increase (with a manometer strain gauge and/or a Hewlett Packard quartz gauge, (Fig. 2) and the associated afterflow rate decreased (with fullbore spinner Fig. 3) with time. Having rate and pressure data, one can use convolution and deconvolution techniques [10 11] to eliminate wellbore storage and evaluate early time data for reservoir permeability, skin, and pressure. Data collection is normally only necessary for a few hours. Finally, up and down passes can again be made with the production logging tool while the well is shutin to identify any shutin crossflow problems.

The procedure for running a drawdown test is very similar to that of a buildup test. The production logging tool is first run in the shutin well and placed just above the zone to be tested. The well is then opened to flow. The corresponding rate increase and pressure decrease is measured versus time. The same data analysis technique is used as in the buildup test for reservoir permeability, skin damage, and pressure. This technique has the advantage over conventional drawdown testing since a constant flow rate is no longer necessary for proper analysis.

After enough data are obtained for accurate analysis (usually a couple of hours), up and down passes can be made to determine the well's flow profile.

The ability to measure downhole flow rate and pressure simultaneously allows for creativity in test design to gain the maximum information about the reservoir. For example, since changes in downhole rate and pressure transients can be measured and used to evaluate reservoir parameters, well testing is no longer limited to buildup or drawdown tests. A simple rate change at the surface will induce a transient into the formation. How that formation "accepts" the transient is a function of the reservoir's permeability and skin and is reflected in changes in rate and pressure with time. Having this powerful ability to measure formation parameters by just inducing transients and measuring the corresponding rate and pressure changes opens up a whole new dimension in well testing.

One such technique is multilayer well testing, which has been described in detail by Kucuk et al.[12, 13]

Additional benefits of the TRAP technique can be gained from production logging passes made at varying flow rates. Changes in a well's flow profile at varying production rates are a reflection of the reservoir flow properties. More importantly, they are a reflection of the reservoir behavior itself. Combining multiple production logging passes with transient rate and pressure analysis can determine what a reservoir is doing and why. This becomes very crucial when deciding what to do with a particular well or field. Questions such as, "is a workover beneficial?" or "is additional drilling necessary?" can be more easily and logically addressed.

TRANSIENT RATE AND PRESSURE THEORY

Multiple-rate pressure transient testing theory and technique is well documented by Earlougher[14] and others. All well tests are transient rate and pressure tests in theory. In "conventional" well testing, however, the rate variable is eliminated. For buildup tests, the well is flowed at a "constant" rate and then shutin; thus the surface rate becomes "zero". Conventional transient pressure analysis is then performed with the assumption that only pressure and time are variables. For drawdown tests, the well is initially at zero flow rate and then produced at a "constant" surface rate. Analysis is then performed with declining pressure and time being assumed as the only variables. This pressure transient testing technique can be very good, but it can also lead to inaccurate analysis. In low-permeability gas wells, afterflow and wellbore storage effects can last for days or even weeks masking the ability to adequately analyze pressure transients for reservoir permeability, skin, pressure, and continuity. For this reason, many gas wells are seldom analyzed.

The reason wellbore storage problems exist in conventional transient pressure analysis is very simple. Bottomhole pressures are being combined with surface flow rates. As mentioned earlier, rate and pressure are an inherent part of well testing. Conventional well testing attempts to eliminate the rate variable by assuming surface flow rate is equal to bottomhole flow rate; in reality, it is not. This common assumption is the main problem associated with conventional well testing in low-permeability gas wells. A further problem in analyzing gas wells with conventional techniques is the fact the wellbore storage coefficient is constantly changing with time.

Elimination of the wellbore storage effect can be easily accomplished by simply measuring downhole flow rate. This could be afterflow in a buildup test or rate changes in a multirate test without total shutin.

Convolution of the rate and pressure data uses the special application of the principle of superposition, as does multiple rate testing. Multiple rate testing analysis breaks the flow rate changes down to a series of discreet steps, and assuming the log approximation to the line source equation is valid, is defined as:[14]

$$\frac{p_i - p_{wf}}{q_n} = m' \sum_{j=1}^{n} \left[\frac{(q_j - q_{j-1})}{q_n} \log (t - t_{j-1}) \right] + b'$$

Plotting of this data will appear as a straight line where:

$$m' = \frac{162.6\ B\mu}{kh}$$

and intercept

$$b' = m' \left[\log \left(\frac{k}{\phi \mu c_t r_w^2} \right) - 3.2275 + 0.86859\ s \right]$$

The step-wise approximation improves as the time intervals become smaller. Having continual rate and pressure data from the production logging tool (every second) allows modification of the step-wise approximation to a continual integral. This enhances the validity of the analysis and can be written as [5, 6]

$$\Delta p_{wf}(t) = \int_0^t q'D(r) \Delta p_{sf}\ (t-r)\ dr$$

$$= \int_0^t qD(t-r) \Delta p'_{sf}\ (r)\ dr + \Delta p_s\ qD(t)$$

For buildup tests, the time variable t is replaced by Δt (the pressure buildup time step). The above equation shows that $\Delta p_{sf}(t)$, the influence function, is the only unknown. Two approaches, known as convolution and deconvolution, can be used to evaluate these data. Details of these techniques can be found in Refs. 5 and 6. Convolution assumes a known reservoir model (radial, linear) and calculates reservoir parameters accordingly, while deconvolution is used to identify the actual reservoir flow regime and appropriate reservoir model.

FIELD EXAMPLES

Following are two deep Fusselman gas well examples from the Delaware basin in west Texas. Both wells had similar production problems; they were making high volumes of water. However, the reasons for high water production were drastically different. Test design for both wells was very similar. Results substantiate the value of the TRAP technique for understanding reservoir dynamics.

Field Example - Reservoir Fingering

The following example is a deep Fusselman gas well located in west Texas. The well was flowing at a surface rate of approximately 845 Mcf/D and 1339 BWPD prior to testing. The reservoir itself is a structural trap with this particular well on the flank of the structure. This particular field had few well test data because of the harsh downhole environment (+300^{o}F and 5,000 ppm H_2S), which had created testing problems in the past. The objective of the test was fourfold. The first objective was to obtain a flow profile of the entire perforated interval to understand which zones were contributing, amounts, and fluid type. The second objective was to obtain another flow profile with the well flowing at a different rate to see if the profile was changing. The third objective was to obtain current effective permeability to gas, extrapolated reservoir pressure, and current skin conditions. Fourth, it was necessary to obtain all the data in a very short time frame. These objectives were met along with an understanding of why the reservoir was performing as it was and what the best possible solutions to alleviate the problem were.

To begin the TRAP test the wireline production logging tool, consisting of a fullbore spinner (flow rate), a manometer strain gauge (pressure), a gradiomanometer* (fluid density) and temperature sonde, was lowered into the well. With the well flowing at its normal producing rate (845 Mcf/D and 1339 BWPD), up and down production logging passes were made over the producing interval from 18,820 ft to 18,940 ft to determine the well's normal flow profile. The profile indicated water and gas to be entering all perforations, with most of the water entering the bottom set of perforations and most of the gas entering the top set of perforations. This information alone might lead one to believe that squeezing off the bottom set of perforations would be a viable solution to minimize water production and be the best economic solution for this particular well.

To improve the "picture" of this wellbore, another flow profile was studied with the well flowing at a different rate. The suface choke was opened and the well was allowed to flow at 1020 Mcf/D and 1632 BWPD. Interesting things began to happen. All zones were contributing as before, except the increased water production was coming from the top of the formation and the increased gas production was coming from the middle of the formation. Water production from the top of the reservoir increased 150% while gas production from the middle increased 81% (Fig. 4).

After the two flow profiles were generated, the production logging tool was placed just above the top perforation. Stationary bottomhole flowing pressure and rate were being monitored with time. The well was then shutin at the surface. Sandface buildup pressure (Fig. 2) and afterflow decline (Fig. 3) were being measured versus time. Afterflow lasted for approximately 21 minutes. The entire buildup test lasted for 40 minutes. Correct analysis for effective permeability to gas, current skin condition, and extrapolated pressure P* was obtainable as a result of rate-normalization of the pseudopressures. Attempts to do conventional transient pressure analysis with Horner plots would be in error because of wellbore storage masking early time data. Fig. 5 is the sandface rate convolution plot, where an effective permeability to gas is calculated to be 0.058 md., and an overall skin factor is calculated as -1.8. Fig. 6 is the modified Horner plot. This plot takes rate effects into account and is used to calculate a more accurate P* of 8303 psig.[6] Fig. 7 is the conventional Horner plot. Since it is being affected by wellbore storage, analysis will be in error. Permeability will be too low and P* will be too high (0.028 md. and 9764 psig). The value of these data is how they relate to the production logging information and how when all information is combined, they define the dynamic reservoir condition. Once it is understood why the reservoir is acting as it is, logical decisions can be made for the overall economic benefit of the reservoir.

The following conclusions can be made from this TRAP test. The current reservoir pressure is very close to original reservoir pressure which indicates a strong water drive. The initial production logging pass shows water and gas entering throughout the gross pay interval, which suggests a flank water drive. The second production logging pass shows increased water production from the top of the formation and increased gas production from the middle of the reservoir. Knowing now that there is a flank water drive, it can be concluded that there is a reservoir fingering problem. It can further be determined that there is a special form of fingering occurring known as water overrunning and water underrunning.

Knowing this information, two action plans can be formulated; one for the well and one for the reservoir. To increase recoverable reserves in this particular well, one could increase perforation density in the middle of the formation. This would reduce the pressure drop across this increased gas flow area and allow more production before water completely overruns the gas. To increase recoverable reserves in this reservoir, one could put this well on artificial lift and produce water as quickly as possible. Since this well is on the flank of the structure, it would be best to sacrifice it and save the upstructure wells from the water drive. Improved recovery from the field will be seen if the impact of the flank water drive is reduced.

Field Example - Natural Fracturing

This example is also a deep Fusselman gas well in the Delaware basin of west Texas. Prior to testing, this well was flowing approximately 3674 Mcf/D and 1301 BWPD. Unlike the previous example, water production increase was more rapid in this well. It was thought water had broken through in the bottom of the producing interval, or that water could be channeling up behind pipe. The objective of this test was to simply identify water entry points and determine if it could be squeezed off. The well test part was done to get an idea of reservoir pressure and effective gas permeability, since the tool was already in the hole and it would only take an additional 45 minutes. Not only were the objectives met, but the well test part brought together the whole picture of what was happening and why.

The production logging tool was first lowered into the well (with the same sondes as the previous example) while it was flowing. Up and down logging passes were then made over the entire completion interval from 17,187 to 17,280 ft. The flow profile indicated all the water and gas to be coming from 17,216 ft. and higher (Fig. 8). Perforations from 17,220 ft and below were not contributing any fluid. Another profile was made at a higher flow rate with similar results. A channel behind pipe could explain the quick appearance of water, especially since it was being produced high in the formation. With this information alone, one may attempt to squeeze the perforations, reperforate the top of the formation, and hope one would regain water-free production. In this case, combining the well testing information with the flow profile gave valuable insight into why the reservoir was producing as it was, and why a potential squeeze and reperforate workover was not viable.

After the production logging profile was complete, the tool was placed just above the top perforation. With the tool measuring sandface flowing pressure and rate, the well was shutin at the surface for a buildup test. Bottomhole pressure buildup (Fig. 9) and afterflow decline (Fig. 10) were measured versus time. The buildup test lasted 45 minutes. The tool was then removed and the well was put back on line.

Because of the well's fairly high permeability, conventional Horner analysis for effective gas permeability and reservoir pressure was adequate (Fig. 11). For comparison, the sandface rate convolution plot agrees very well during early time analysis (Fig. 12). However, the downhole afterflow rate data allow proper identification of the reservoir's flow regime. By scaling the pressure with the flow rate data, the true formation characteristics are seen instead of wellbore storage. In this case, the modified Horner plot exhibits parallel lines, indicative of natural fracturing (Fig. 13). This information is very valuable in the overall evaluation of the TRAP test. Natural fracturing explains a quick breakthrough in water production. It also explains why production is coming from the top of the zone.

With this information, the reservoir can be evaluated and plans can be made as to what should be done with this particular well. It is now obvious that squeezing and reperforating is not a viable solution. Living with the condition is the best solution. Even though it may not be the answer one wants to hear, it saves one from wasting money on an unattainable solution.
The Gradiomanometer measurements were a very interesting input into the evaluation. Flowing downhole fluid density was approximately 0.66 g/cm^3, indicative of fairly high volumes of water with the gas. After shutin, bottomhole fluid density declined to 0.42 g/cm^3 (Fig. 14). In the previous example, downhole fluid density was 0.73 g/cm^3 and never really changed during flowing and shutin conditions (Fig. 15). Inference can be made to the strong water drive in the previous example keeping fluid density high regardless of the well's operating condition, whereas in this example, water movement from the fractures to the wellbore is dependent on the wellbore operating in a producing condition.

CONCLUSIONS

Combining transient rate and pressure data with production logging data is a significant improvement to using either one separately in evaluating dynamic reservoir conditions. The combined power of these techniques not only reveals what is happening to the reservoir/wellbore but also, more importantly, explains what is the most economic solution to the situation and why. The TRAP technique can be incorporated throughout the life of the reservoir. Its most powerful application is after initial completion, and continuing throughout the life of the well, allowing for proper identification of initial, current, and expected conditions. Waiting until problems arise in a well or reservoir may be too late to save a well/reservoir. At the very least, it is poor reservoir management. During these times, when prices and demand are so unsure, sound economic decisions are vital.

The field examples discussed in this paper indicate the necessity to see the "whole" picture to properly evaluate a reservoir. Improper decisions could result without looking from an overall reservoir management philosophy. The TRAP technique is an excellent approach to proper reservoir management of low-permeability gas wells for three reasons:

1. It identifies exactly what zones are producing and at what amounts. This information can be used for improving reserve estimate calculations, studying completion effectiveness, and identifying crossflow.
2. It identifies formation parameters such as permeability, skin, and reservoir pressure, along with flow regimes and drive mechanism in a very short time as a result of its ability to incorporate multiple-rate testing theory.
3. Combination of all data determines current reservoir dynamics. This allows for proper reservoir management decisions to be made from both an individual well's standpoint as well as from an overall reservoir point of view.

NOMENCLATURE

c_t	=	system total compressibility, psi^{-1}
b'	=	multirate semilog plot intercept
B	=	formation volume factor, RB/STB
h	=	formation thickness, ft
k	=	formation permeability, md
j	=	sampling rate for multirate test
m	=	number of data points
m'	=	slope of multirate test data plot, psi/cycle STB/D
p	=	average reservoir pressure, psi
p^*	=	Horner false pressure, psi
p_i	=	initial pressure, psi
p_{wf}	=	bottomhole flow pressure, psi
p_{sf}	=	pressure of well producing at constant rate, psi
p_{ws}	=	bottomhole shutin pressure, psi
p_s	=	pressure drop caused by skin
q	=	stabilized or constant rate
qn	=	flowrate during nth rate period, STB/D or Mcf/D
$qD(t)$	=	dimensionless downhole flowrate, $\frac{q_{sf}(t)}{qr}$
q_{sf}	=	downhole flowrate, B/D
q_r	=	reference flowrate, B/D
r_w	=	wellbore radius, ft
s	=	skin factor
t_C	=	dimensionless time
t_p	=	production time, hours
t	=	running test time, hours
β	=	parameter vector
$'$	=	indicates derivative with respect to time
ϕ	=	porosity
μ	=	viscosity, cp
D	=	difference
η	=	computed dependent variable

REFERENCES

1. Ahmed, U., Kucuk, F., Ayestaran, L.: "Short Term Transient Rate and Pressure Build-Up Analysis of Low Permeability Wells," paper SPE 13870 presented at the 1985 SPE/DOE Symposium on Low Permeability Reservoirs, Denver, May 19-22.

2. Meunier, D., Wittman, J.J., and Stewart, G.: "Interpretation of Pressure Build-Up Test Using In-Situ Measurement of Afterflow," paper SPE 11463 presented at the 1983 Middle East Oil Technical Conference, Manama, Bahrain, March 14-17.

3. Guillot, A.Y., and Horne, R. N.: "Using Simultaneous Flow Rate and Pressure Measurements to Improve Analysis of Well Tests," paper SPE 12958 presented at the 1984 European Petroleum Conference, London, October 25-28.

4. Thompson, L.G. and Reynolds, A.C.: "Analysis of Variable Rate Well Test Pressure Data Using Duhamel's Principle," paper SPE 13080 presented at the 1984 SPE Annual Technical Conference and Exhibition, Houston, September 16-19.

5. Van Everdingen, A.F. and Hurst, W.: "The Application of the Laplace Transformation to Flow Problems in Reservoirs," Trans., AIME (1949) 186, 305-324.

6. Kucuk, F. and Ayestaran, L.: "Analysis of Simultaneously Measured Pressure and Sandface Flow Rate in Transient Well Testing," paper SPE 12177 presented at the 1983 SPE Annual Technical Conference and Exhibition, San Francisco, October 5-8.

7. Thompson, L., Jones, J.R., Reynolds, A.K., and Raghaven, R.: "Analysis of Pressure Build-Up Data Influence by Wellbore Phase Distribution," paper SPE 12782 presented at the 1984 SPE California Regional Meeting, Long Beach, April 11-13.

8. Fetkovich, M.J. and Vienot, M.E.: "Rate Normalization of Build-Up Pressure Using Afterflow Data," paper SPE 13081 presented at the 1983 SPE Annual Technical Conference and Exhibition, San Francisco, October 5-8.

9. Ahmed, U. and Watson, J.T.: "Use of Bottomhole Transient Rate Data to Enhance Transient Pressure Analysis," paper SPE 15422 presented at the 1986 SPE Annual Technical Conference and Exhibition, New Orleans, October 5-8.

10. Carter, R., Kucuk, F., and Ayestaran, L.: "Numerical Solution to Convolution Integral with Constraints," paper presented at the 1985 SEG/SIAM/SPE Conference on Mathematical and Computational Methods in Seismic Exploration and Reservoir Modeling, Houston, January 21-24.

11. Stewards, G., Meunier, D., and Wittman, M.J.: "Afterflow Measurements and Deconvolution in Well Analysis," paper SPE 12174 presented at the 1983 Annual Technical Conference and Exhibition, San Francisco, October 5-8.

12. Kucuk, F., Karakas, M., and Ayestaran, L.: "Well Test Analysis of Commingled Zones Without Crossflow," paper SPE 13081 presented at the 1984 SPE Annual Technical Conference and Exhibition, Houston, September 18-19.

13. Kucuk, F.J., Shah, P.C., Ayestaran, L., and Nicholson, B.: "Application of Multilayer Testing and Analysis; A Field Case," paper SPE 15419 presented at the 1986 SPE Annual Technical Conference and Exhibition, New Orleans, October 5-8.

14. Earlougher, R.D., Jr.: Advanced Well Test Analysis, Monograph Series, SPE, Dallas, Texas (1977).

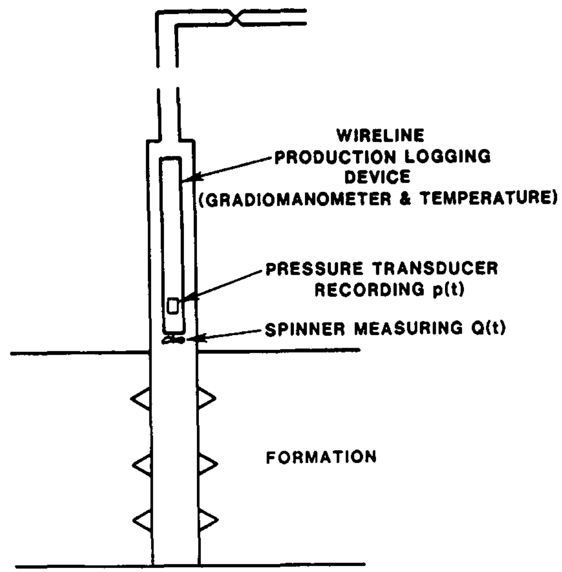

Figure 1—Production logging tool position for well test

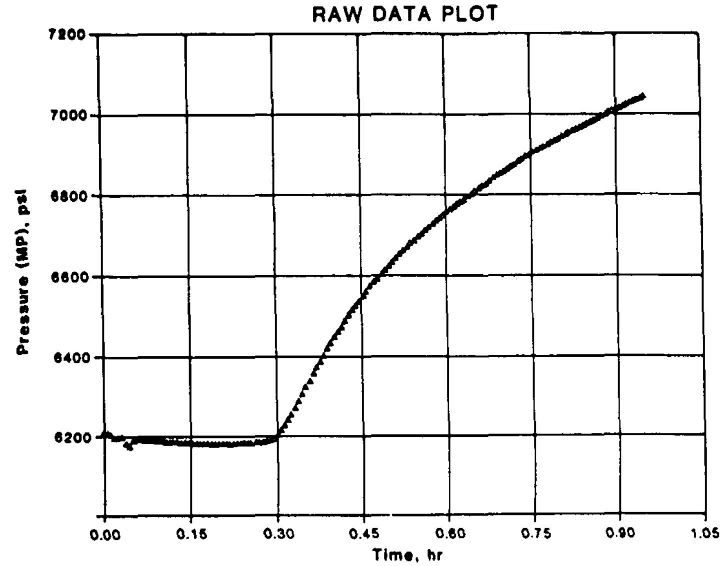

Figure 2—Bottomhole transient pressure buildup data for Example 1

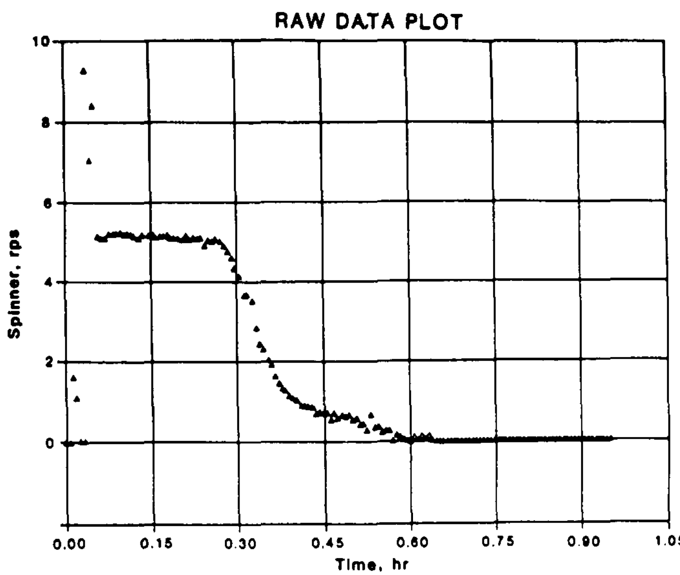

Figure 3—Bottomhole transient rate afterflow data for Example 1

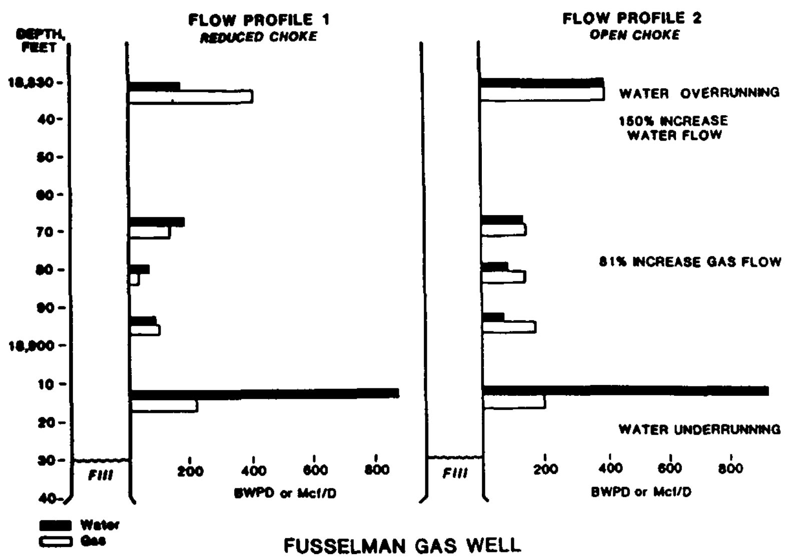

Figure 4—Production logging flow profiles for Example 1

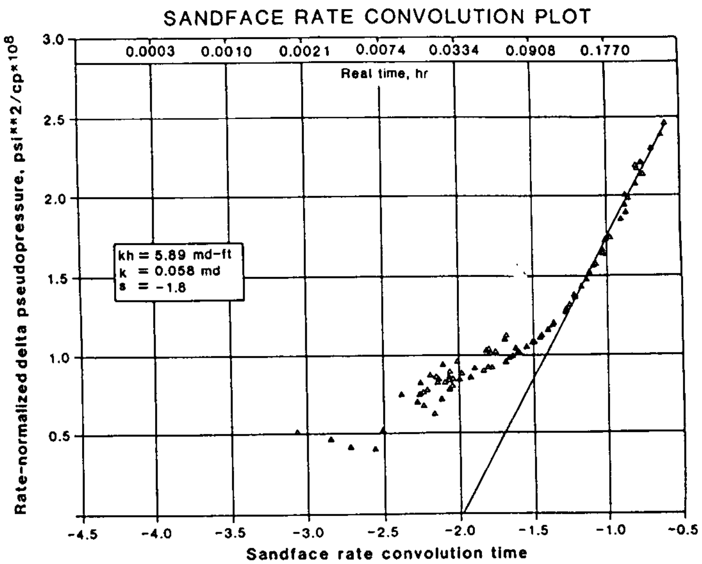

Figure 5—Bottomhole rate convolution plot for Example 1

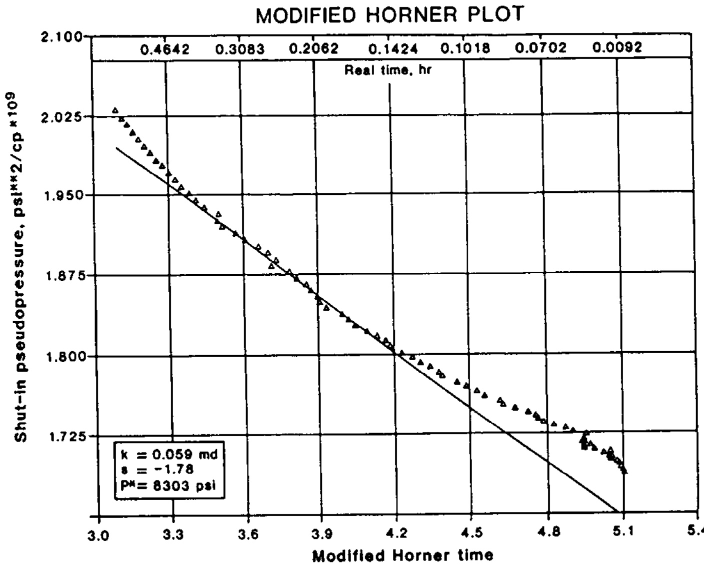

Figure 6—Modified Horner plot for Example 1

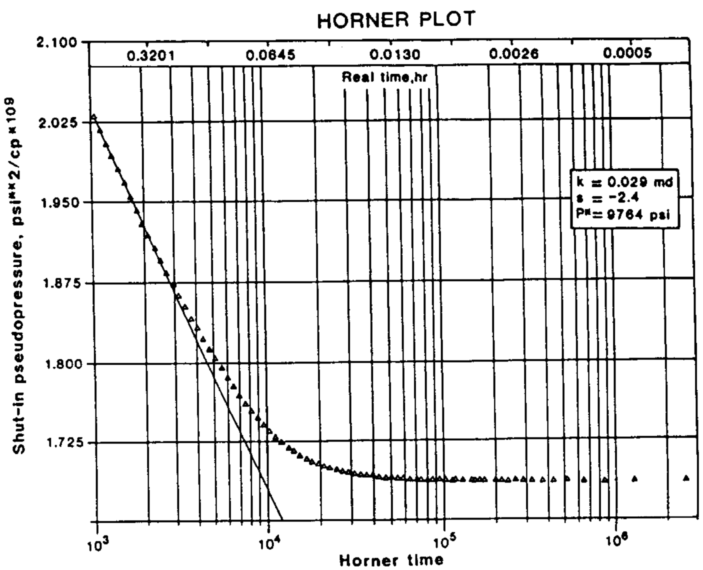

Figure 7—Horner plot for Example 1

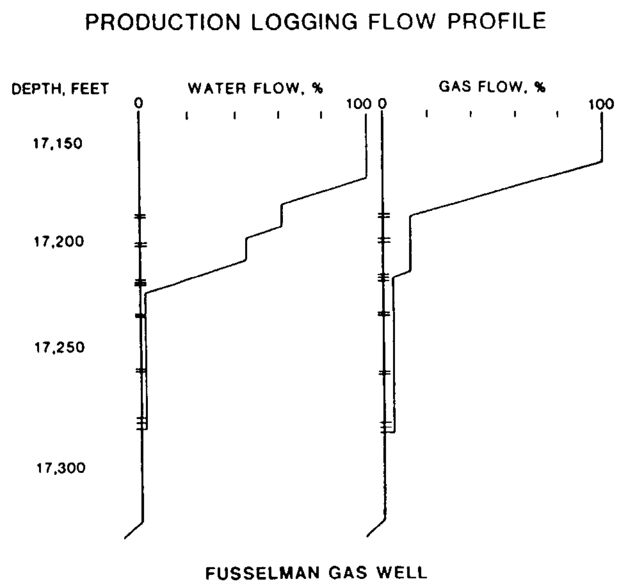

Figure 8—Production logging profile for Example 2

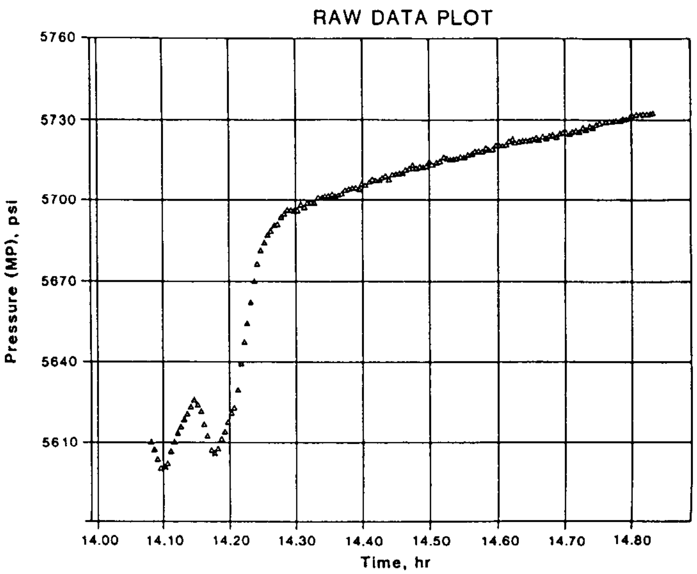

Figure 9—Bottomhole transient pressure buildup data for Example 2

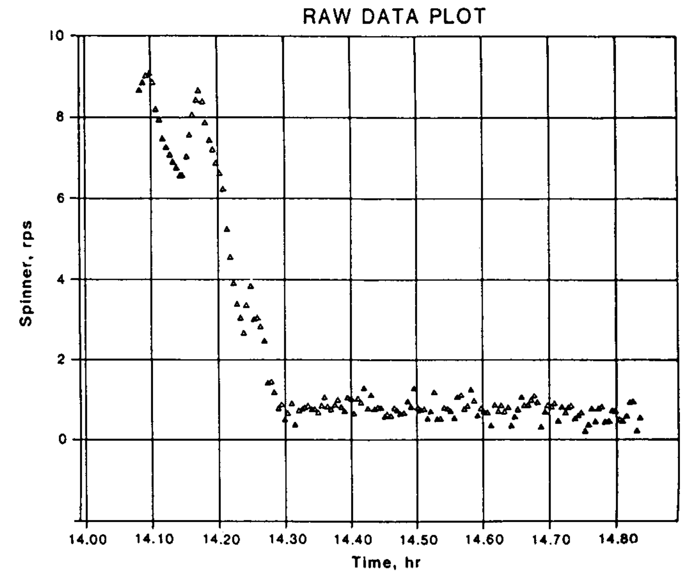

Figure 10—Bottomhole transient rate afterflow data for Example 2

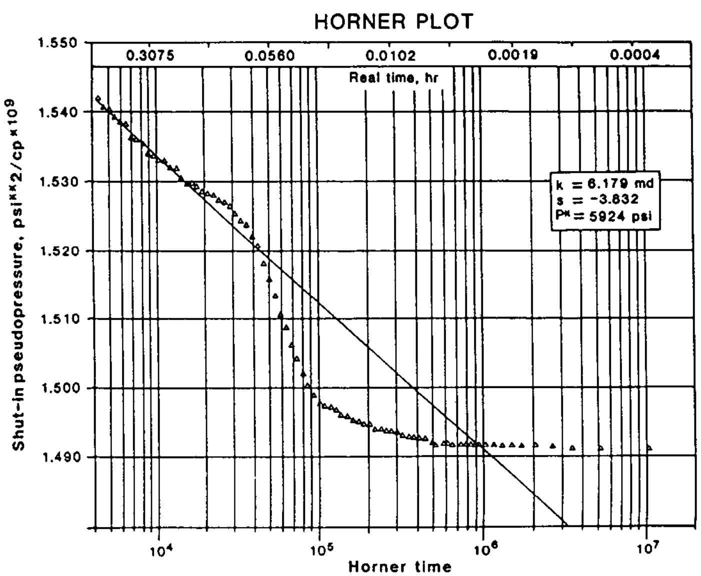

Figure 11—Horner plot for Example 2

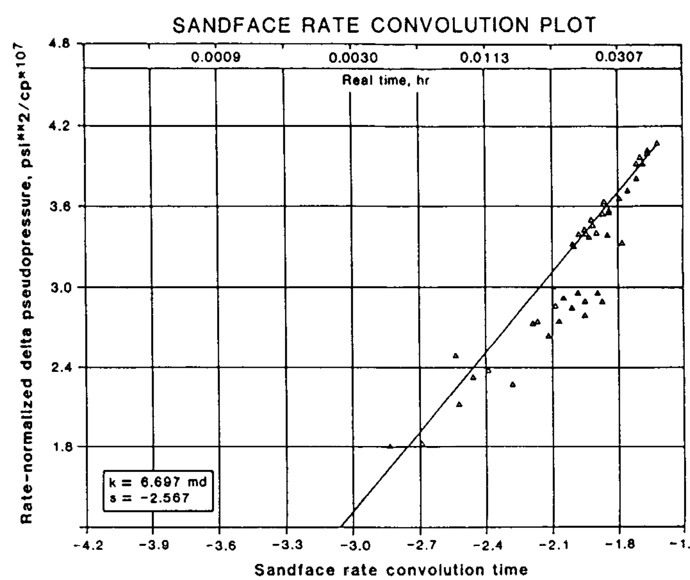

Figure 12—Bottomhole rate convolution plot for Example 2

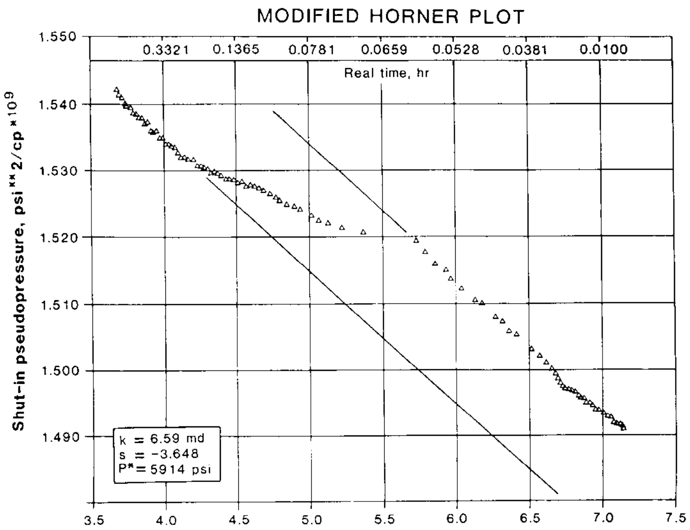

Figure 13—Modified Horner plot for Example 2 showing natural fracturing

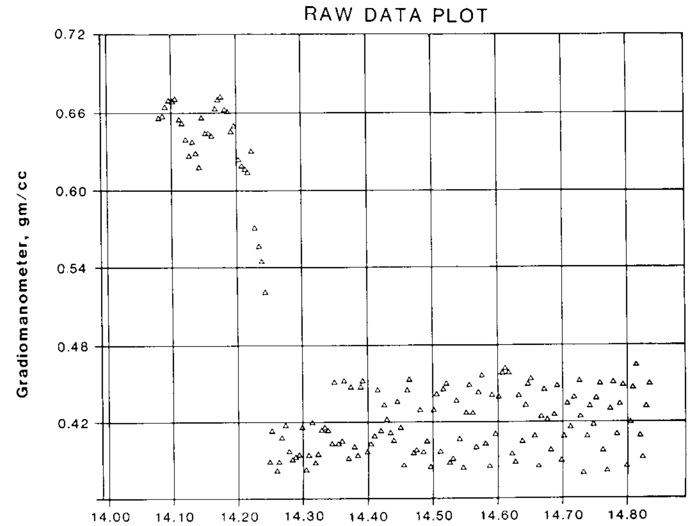

Figure 14—Gradiomanometer (density) plot for Example 2

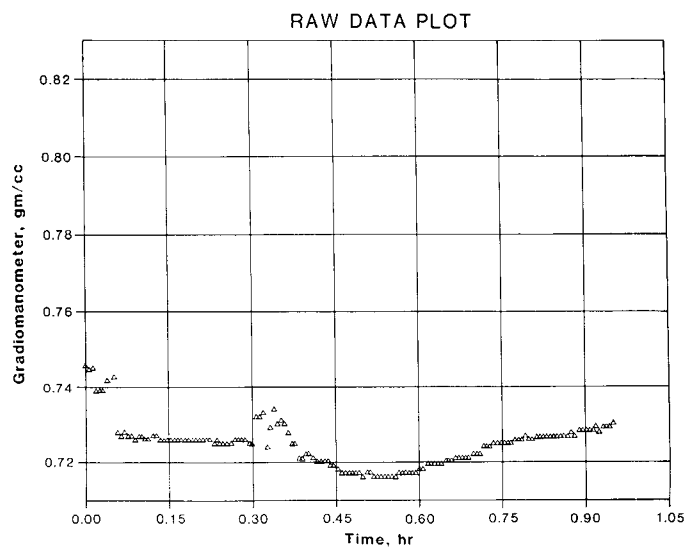

Figure 15—Gradiomanometer (density) plot for Example 1