FIELD RESULTS VERIFY AFTERFLOW ANALYSIS FROM D.S.T. AND SHORT-TIME PRODUCTION TEST*

E.E. MILNER and D. A. WARREN, JR.,
Johnston-Schlumberger, and P.M. CLAIBORNE, Henry Engineering

INTRODUCTION

The McKinley afterflow method has been successfully used to interpret drill-stem tests (D.S.T.) and short-time production tests where conventional analysis methods cannot be employed, or are difficult to apply.[1] Although the afterflow method has other applications, this study will be limited to pressure buildup behavior. Throughout this paper the McKinley afterflow buildup method will be referred to as simply the afterflow method.

The Horner method is the most commonly used technique for interpreting short-time test data, so the following examples will be compared to this method.[2] Effective permeability, wellbore damage or stimulation, radius of investigation, and expected production rate are the reservoir parameters obtainable by the afterflow method. Exact numerical values are not obtained by this or any curve-matching procedure, but the order of magnitude of the answers is sufficiently close to help make decisions that are normally made from a short-time test. Six examples have been selected to illustrate the application of the afterflow method.

These examples are typical of many tests analyzed from producing areas around the world. They have been selected because of the large amount of followup data made available by Henry Engineering and other industry companies.

Reference 1 describes the analytical treatment of the afterflow method. Utilization of the afterflow method to D.S.T. and short-time production tests has previously been described by Milner and Warren in S.P.E. number 4123. Our contribution through this study is to present verification, by actual field results, of the afterflow method to certain types of problems.

APPLICATIONS AND DISCUSSION

The afterflow method can be used to analyze oil, water, or gas wells when conventional analysis methods cannot be used. Some of these applications are as follows.

(1) When shutin buildup times are insufficient and the proper straight line for analysis by the Horner method has not been reached. (Example 6)

(2) When two zones, without crossflow except in the wellbore, are present in the test interval and the proper straight line for Horner analysis is difficult to determine. In many instances when the transmissibility of the two zones or the pressure in the two zones is quite different, the entire buildup curve on a Horner plot will appear to be in afterflow when in reality the correct straight line for analysis is present but difficult to recognize and can occur very early in the buildup. Examination of the afterflow plot times and matches can aid in selecting the correct portion of the Horner plot for analysis. (Example 4)

(3) When a stimulated wellbore is present. The Horner plot of a condition such as this quite often will not give a distinguishable straight line or will appear to be in afterflow for the entire buildup. The afterflow method can be used to analyze this condition and also aid in selecting the proper straight line on the Horner plot. The stimulated effect has been observed on most D.S.T. buildups between 2 and 20 minutes. This of course means that the early time data on a buildup curve should be looked at in 1- or 2-minute time increments.

*Reprinted based on SPE Preprint 6055 with the permission of the Society of Petroleum Engineers (Copyright Owner).

Permeability can be determined for both the stimulated area and the matrix. These answers are only order of magnitude, usually too high when using radial flow equations. The Horner slopes obtained under many stimulated wellbore conditions such as this appear to be too small. Permeability values thus obtained should be used with caution. Perhaps the most important use of the afterflow method is to predict the flow rate expected when the stimulated area has been depleted. This rate can be predicted very simply and accurately from the afterflow analysis by multiplying the actual test rate by the transmissibility ratio of matrix to stimulation.

$$Qp = \frac{J/f \text{ Formation}}{J/f \text{ Wellbore}}$$

Even though the numerical values of permeability may not be correct, the transmissibility ratio is valid. This predicted rate has proven accurate in all cases so far verified by actual production (Examples 1, 2, 3, 4 and 5 in this study).

The known conditions that cause a stimulated wellbore effect are (1) artificial stimulation, (2) naturally occurring fracture systems with a tight matix, and (3) transmissibility decrease away from wellbore due to zone tightening or thinning.

LIMITATIONS OF AFTERFLOW METHOD

The afterflow method does not give correct answers for every condition and was not developed to do so. It is just as important to know when not to apply this method as it is to know when to use it.

The limitations encountered are as follows.

(1)When the buildup curve is still in extremely strong afterflow, the answers obtained will not be representative of the formation values.

(2) When very high wellbore damage is present, the early time plot does not fit any of the type curves. Therefore no reservoir calculations should be attempted. This is not a serious drawback, as conventional analysis methods can be applied.

(3) Reservoir pressure must be obtained by some other means and is most often obtained from the initial shutin on a D.S.T.

(4) When boundary conditions such as a fault or other sealing barrier occur, a stimulated effect will show up on the afterflow plot. Geological or geophysical data should be consulted to check these possibilities. The decreasing transmissibility ratio of formation to wellbore should not be used to predict flow rates if these conditions are present.

EXAMPLE PROBLEMS

Example 1. Stimulated Wellbore
Limited Natural Fracture System
With Tight Matrix

This is an open hole test of an 8-foot Georgetown lime section in South Texas that produced gas at an average rate of 1700 MCF/d during the 61-minute initial flow period. Figure 1 is the D.S.T. chart showing the flow and shutin pressure characteristics of the test. Points 2 to 3 on the initial flow indicate a rapid drawdown of bottom hole pressure.

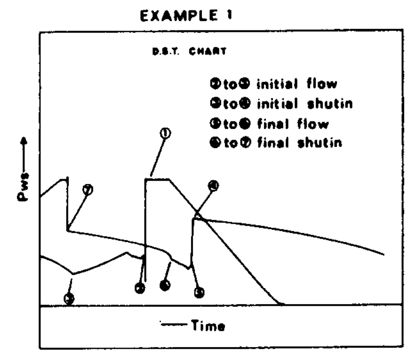

FIGURE 1

The Horner plot, Figure 2, was constructed from the 180-minute initial shutin period. The shape of the plot is typical of a limited fracture and tight matrix system. Note the very early slope (fracture) and long sweeping final pressure rise as the tight matrix repressures the fracture.

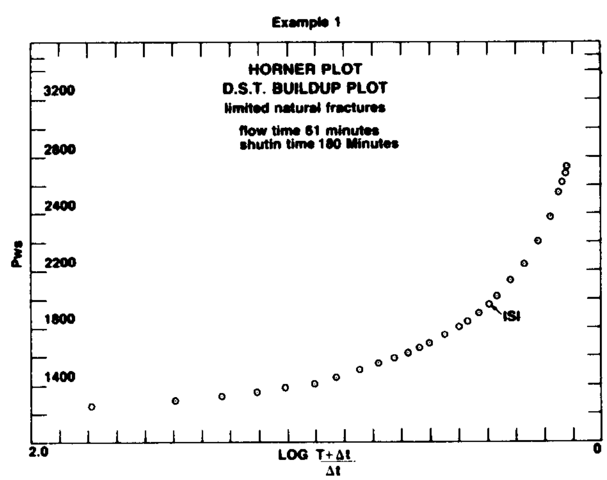

FIGURE 2

The afterflow plot, Figure 3, indicates a stimulated wellbore. The wellbore match value, J/f = 250,000, occurs in two minutes time indicating the fracture only extends a short distance away from the wellbore. The plotted curve continues to break to the right, and the final match value of J/f = 1700 represents the tight matrix. The predicted production rate was calculated to be 11.6 MCF/day.

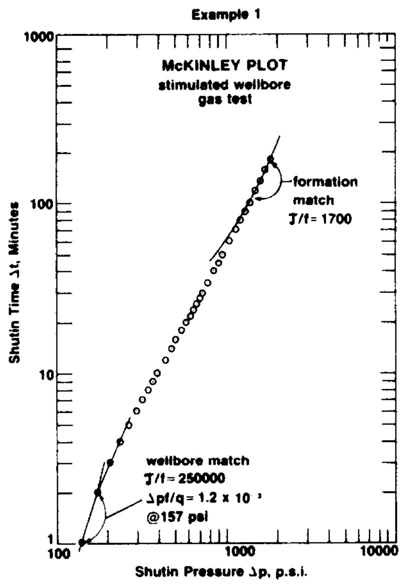

FIGURE 3

$$Qp = 1700 \text{ (test rate) x } \frac{1{,}700 \text{ formation match}}{250{,}000 \text{ wellbore match}}$$

$$= 11.6 \text{ MCF/day}$$

Permeability of the fracture calculated to be 10.1 mds, and the tight matrix 0.07 mds. A radius of investigation of the fracture was calculated to be 35 feet. The well was completed and acidized. After three weeks of testing, the production rate dropped to 0 and the zone was abandoned.

Example 2. Stimulated Wellbore Limited Fracture System With Tight Matrix

This is a 9800-foot open hole test of a 29-foot Pennsylvanian zone in New Mexico that produced oil and water at the rate of 582 barrels/day (82 percent, 45.5-degree API oil, 18 percent water) with a G.O.R. of 2385 to 1.

The Horner plot of initial shutin buildup, Figure 4, by its shape indicates a deep penetrating fracture. Reservoir pressure extrapolation to 3395 PSI is good.

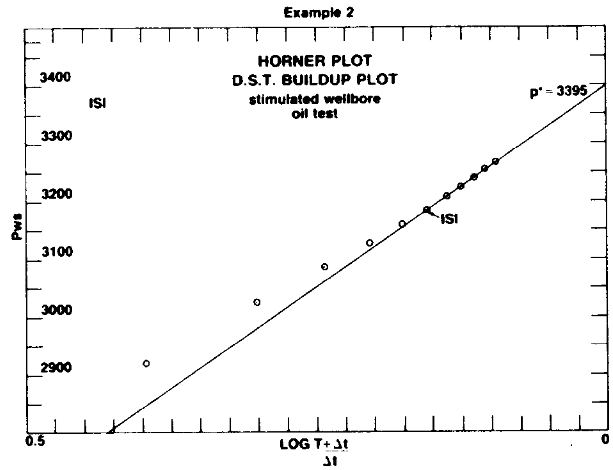

FIGURE 4

The Horner plot of the final shutin buildup, Figure 5, shows a good straight line to be present for the first 15 minutes of buildup. At this point the buildup curve begins to swing upward but does not extrapolate to the initial pressure even though the shutin time was five times as long as the flow time. A limited reservoir is possible.

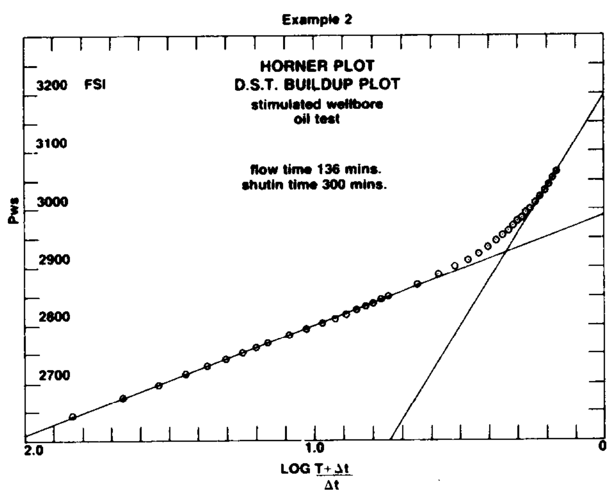

FIGURE 5

The afterflow plot, Figure 6, shows a stimulated wellbore to be present. A decreasing transmissibility ratio of 26.6 was observed.

Formation match J/f = 7500, wellbore match J/f = 200,000. The wellbore match time of 15 minutes corresponds to the early Horner straight line of 15 minutes. The fracture permeability of 7.57

mds calculated by the afterflow method compares to 6.53 mds by Horner. The matrix permeability calculates to be 0.28 mds by the afterflow method with no calculation by Horner.

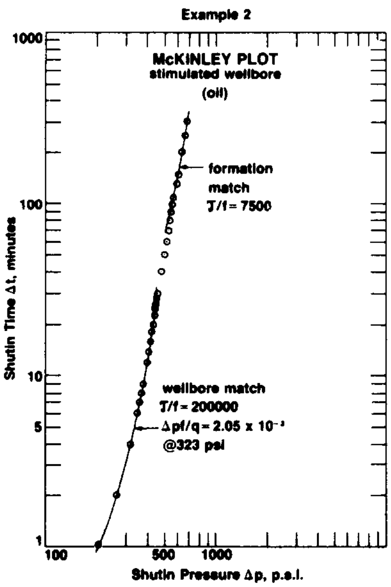

FIGURE 6

The predicted production rate after depletion of the stimulated area was calculated to be 22 bbls/day.

$$Qp = 582 \text{ x } \frac{7{,}500}{200{,}000} = 22 \text{ bbls/day}$$

Completion was made on the well, and after a cumulative production of 800 barrels of oil the well was abandoned producing 20 barrels of water and 8 barrels of oil per day. The net financial loss on this completion was reported to be $133,000.

Example 3. Stimulated Wellbore
Sand Lense With Transmissibility
Decreasing Away From Wellbore

Two drill stem tests were conducted on a 9-foot morrow sand zone in Lea County, New Mexico. Casing was set and a production test was run before pipeline connection was made.

Packer seat failure prevented obtaining pressure buildup data on D.S.T. number 1 during the final shutin. Initial shutin pressure was 4567 PSI. The flow rate on D.S.T. number 2 was initially 15,776 MCF/day and declined to 11,700 MCF/day during the 270-minute flow period. The accompanying drawdown in bottom hole flow pressure is noted on the D.S.T. chart, Figure 7.

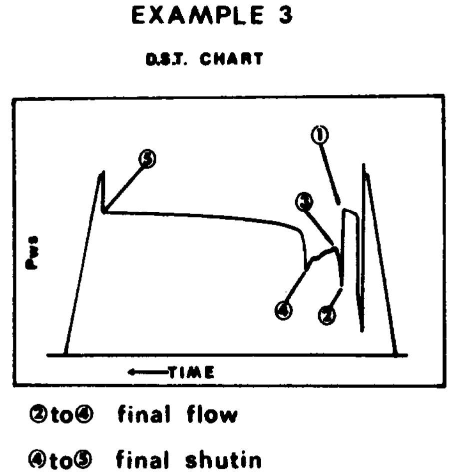

FIGURE 7

The Horner plots of the initial and final shutin buildup curves are shown in Figure 8. Extrapolation of the initial shutin indicates a reservoir pressure of 4447 PSI which is 120 PSI less than D.S.T. number 1. Permeability calculations from the early slope of the final shutin buildup is 47 mds and the damage ratio is 3.36. These values are calculated for the near wellbore area, and the damage shown is probably the result of turbulence. A second slope value could possibly be selected.

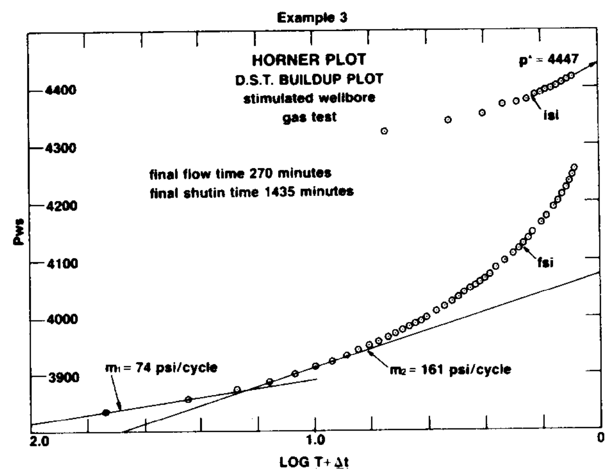

FIGURE 8

The afterflow plot of the D.S.T. buildup (Figure 9) indicates a stimulated wellbore with a decreasing transmissibility ratio of 50 to 1. The predicted production rate after depletion of the stimulated area was calculated to be 232 MCF/day. A production test was run after completion to flow 4294 MCF/day. The Horner plot of this buildup, Figure 10, indicates an early slope value that is identical to the D.S.T. early slope. Permeability calculated to be 15 mds, which indicates the early Horner slope is not correct. The afterflow plot of the production test buildup, Figure 11, again indicates a stimulated wellbore. The decreasing transmissibility ratio indicates a flow rate of 171 MCF/day after depletion of the stimulated area. This value compares closely with the D.S.T. value. The actual point where this occurred was 210 MCF/day as shown by the decline curve, Figure 12. The cumulative production at this time was 80 MMCF of gas. The completion cost of this well was $275,000.

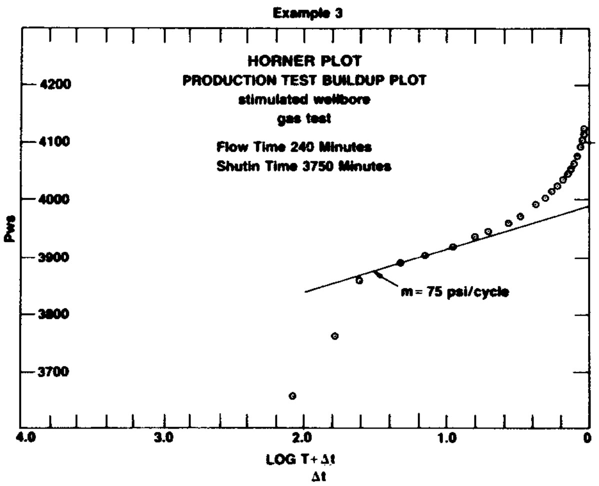

FIGURE 10

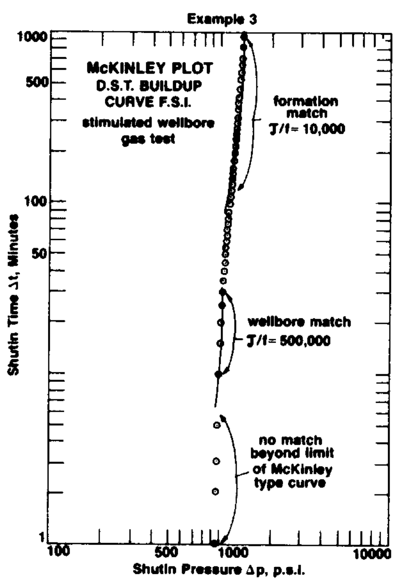

FIGURE 9

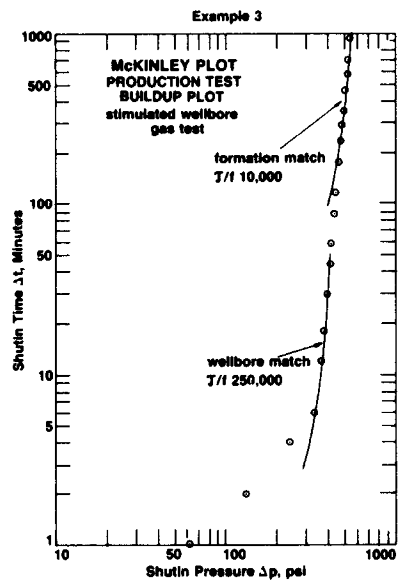

FIGURE 11

Example 4. Two Zones
Production Test (After Acidizing)

Example 4 is 9900-foot strawn gas producer in Eddy County, New Mexico. Two 15-foot-thick limestone zones 50 feet apart were drill-stem tested to flow 3820 MCF/day gas. Mechanical problems prevented buildup pressures being recorded on the final shutin period. Reservoir pressure determined from the initial shutin buildup was 4500 PSI.

The drill stem test chart, Figure 13, clearly shows the two zones during the initial buildup.

Casing was set and both zones were perforated and treated with 15,000 gallons acid; then a production test was conducted to flow a weighted average rate of 893 MCF/day gas during the 1140-minute flow period. The well was then shut in for 5040 minutes.

A Horner plot of the production test buildup curve plotted on a scale of 100 PSI/inch, Figure 14, is difficult to interpret. The expanded scale (20 PSI-inch) Horner plot, Figure 15, shows the

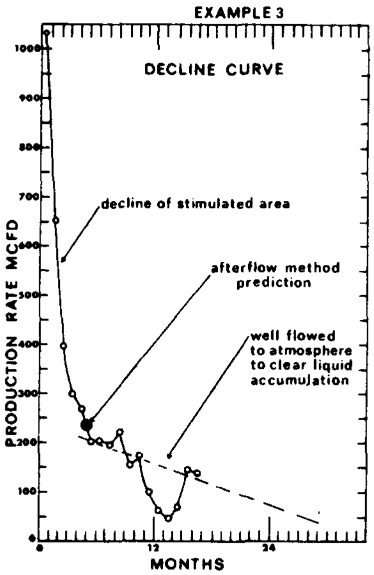

FIGURE 12

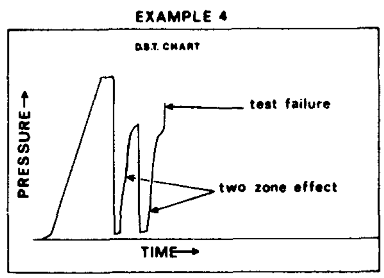

FIGURE 13

characteristics of a two-zone buildup as illustrated by Ramey and Cobb.[3] It is interesting to note that the stimulation effect, proper straight line, transition, flattering and start of the final pressure rise all occur in the first 18 minutes of the buildup.

Most two-zone buildup curves observed from D.S.T. data with pressure scales of 100 PSI/inch or larger will show the proper straight line, transition and flattening all together as indicated by Figure 10.10 in the S.P.E. monograph.[4]

Figure 16 shows the afterflow plot of the production-test buildup curve. The stimulation effect is shown in the first 4 minutes of buildup (wellbore match). The average formation values occur at 6 to 10 minutes (formation match). The flattening and start of final rise occur by 18 minutes.

The decreasing transmissibility ratio of formation to wellbore indicates that the production rate will be 362 MCF/day when the stimulated area is depleted.

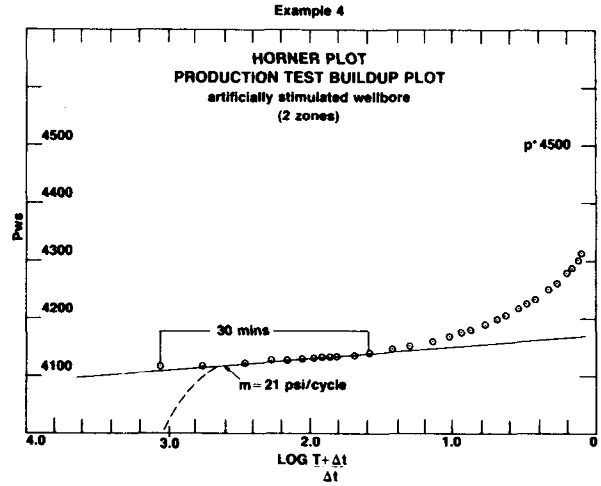

FIGURE 14

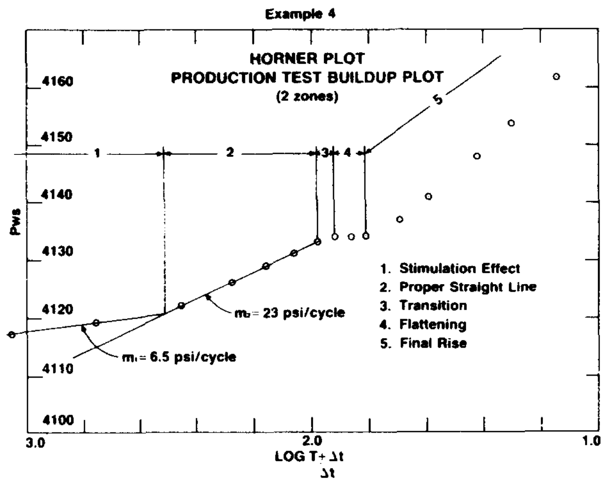

FIGURE 15

The actual production decline curve, Figure 17, shows the rate to be 350 MCF/day when this occurs. Permeability was calculated to be 3 mds by Horner and 5.2 mds by the afterflow method.

Example 5. Damaged Wellbore
Production Test Showing
Stimulated Wellbore After Sand
Fracture

An open hole test of an 18-foot morrow sand in New Mexico produced gas at a rate of 368 MCF/day. The Horner plot of the open hole test, Figure 18, was analyzed to indicate permeability of 0.19 mds and a damage ratio of 2.99. The afterflow plot, Figure 19, indicated a saturation effect during the afterflow period and then directly to a straight portion. No analysis could be made from this plot but was not needed as a good Horner plot was available.

Completion was made and the well treated with 3000 gallons 7-1/2 percent ms acid plus 115,000 SCF nitrogen for damage cleanup and produced gas at 1348 MCF/day . Next the well received a fracture treatment using 28,000 gallons of a complexed alcohol gel and 39,000 pounds of sand. A production test was conducted with the well flowing 4800 MCF/day gas for a 7230-minute flow and then shut in for 3835 minutes. A Horner plot of the production test data, Figure 20, calculated the fracture permeability to be 1.19 mds with a damage ratio of 0.604, which showed the stimulation.

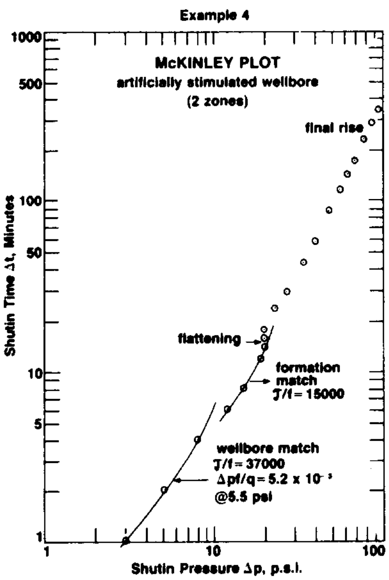

FIGURE 16

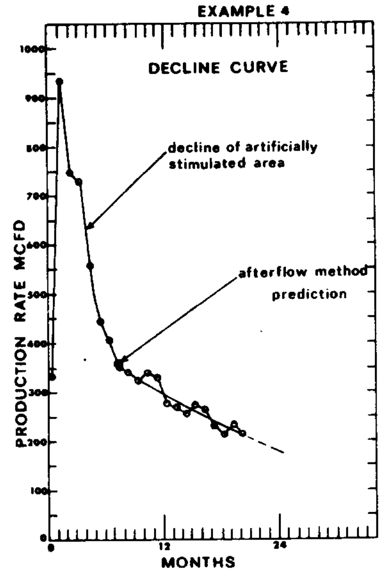

FIGURE 17

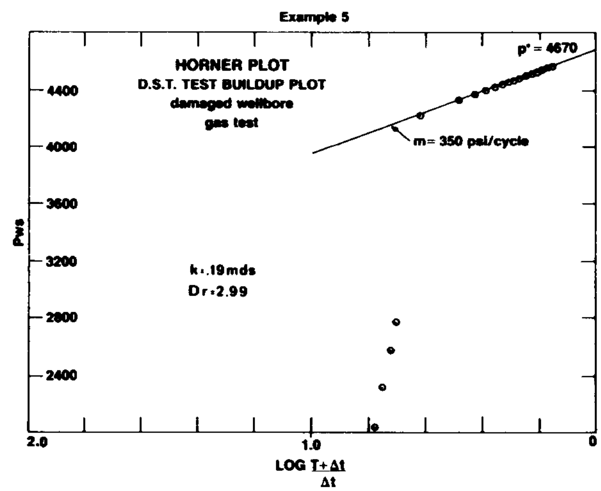

FIGURE 18

Figure 21 shows the afterflow plot of the production-test data, and a stimulated wellbore was indicated. The decreasing transmissibility ratio of 5.41 is shown by the wellbore match value J/f = 20,000 and formation match value J/f = 3700. Permeability of the fracture was calculated to be 1.3 mds (compared to 1.19 by Horner) and the formation permeability was calculated to be 0.24 mds (compared to the D.S.T. Horner value of 0.19 mds). No formation value could be obtained by the Horner method from the production test. This shows the value of the afterflow method for calculating reasonable values of formation permeability for a hydraulically fractured well when the conventional methods do not.

The predicted production rate after depletion of the stimulated area using the decreasing transmissibility ratio from the afterflow analysis was 888 MCF/day. This point occurred at approximately 1100 MCF/day as shown by the production decline curve, Figure 22. The well and pressure data for this test are shown in the appendix as Table 1. Reservoir calculations for this test are shown in Table 2.

Example 6. Damaged Wellbore
Insufficient Shutin Time

This is an open hole drill stem test of 18-foot sand section in West Texas that produced oil at the rate of 101 barrels per day.

The Horner plot shown in Figure 23 shows the reservoir pressure to be 2430 PSI from an

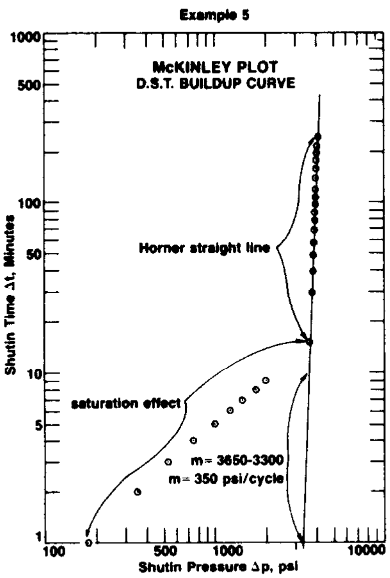

FIGURE 19

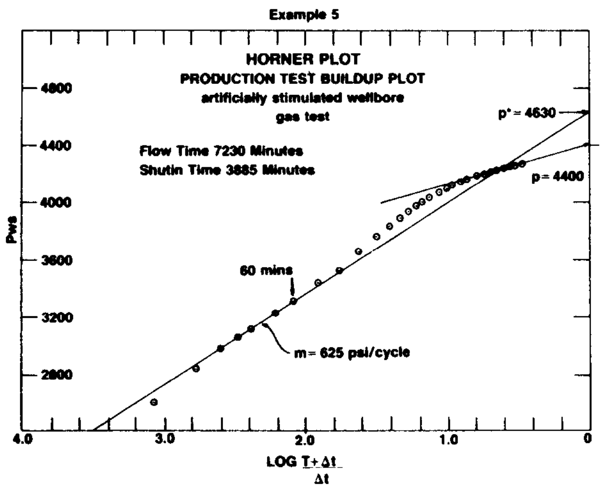

FIGURE 20

extrapolation of the initial shutin buildup.

The final buildup plot appears to have reached a good straight line, but the pressure extrapolation is 33 PSI higher than the initial. Permeability calculated by Horner is 3.65 mds and the damage ratio is 1, indicating no wellbore damage.

Figure 24 shows the afterflow plot, and a damaged wellbore is indicated. Permeability calculated by the afterflow method is 7 mds, and the damage ratio is 1.82.

Upon completion, the well was treated with 3000 gallons mud acid and produced 162 barrels per day oil initially. This rate improvement over the D.S.T. rate is 1.6 times.

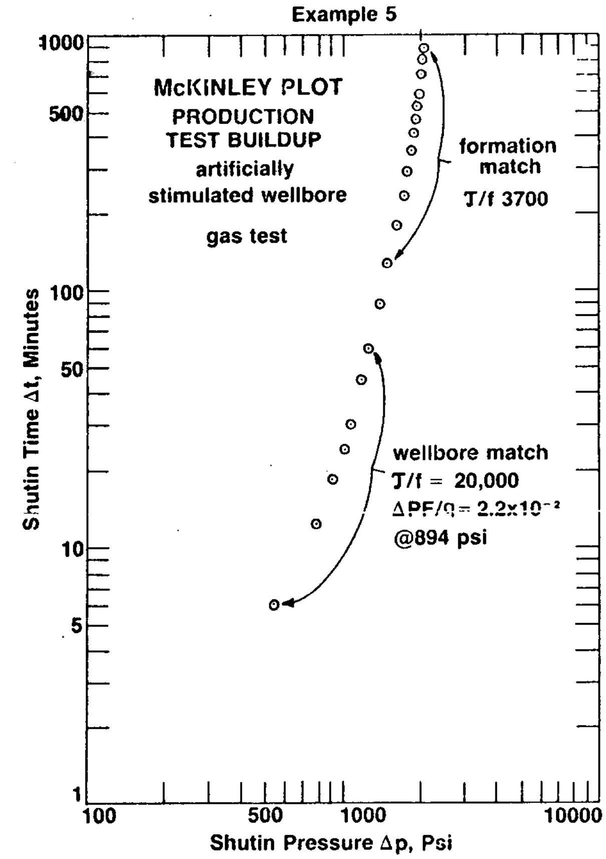

FIGURE 21

TABLE 1—WELL AND PRESSURE DATA FOR EXAMPLE 5 (PRODUCTION TEST)

	Shutin Time Minutes	Pws PSI	Log $\frac{T+\Delta t}{\Delta t}$	μ Cps.	Z	ΔP (Pws − Pwf) PSI
Test Depth = 10,700 ft.	0	2063.00	0.	0.01576	0.88801	0.
Morrow Sand	6	2600.00	3.081	0.01720	0.88293	537.0
h = 18 ft.	12	2844.00	2.781	0.01789	0.88851	781.0
ϕ = 8%	18	2975.00	2.605	0.01828	0.89179	912.0
rw = 2"	24	3061.00	2.480	0.01853	0.89370	998.0
Sp. Gr. Gas = 0.61	30	3119.00	2.384	0.01870	0.89676	1056.0
B.H.T. = 180°F. = 640°R.	45	3225.00	2.209	0.01901	0.90058	1162.0
Flow Time = 7230 minutes	60	3314.00	2.085	0.01927	0.90509	1251.0
Shutin Time = 5040 minutes	90	3442.00	1.910	0.01964	0.90849	1379.0
Qg = 4800 MCF/day	130	3533.00	1.753	0.01991	0.91365	1470.0
Qe = 4242 Res. Bbls/day	180	3670.00	1.615	0.02031	0.91979	1607.0
Pi = 4670 PSI	240	3774.00	1.493	0.02061	0.92499	1711.0
Pwf = 2063 PSI	300	3847.00	1.400	0.02083	0.93214	1784.0
P avg. = $\frac{4670 + 2063}{2}$ = 3367 PSI	360	3905.00	1.324	0.02100	0.93265	1842.0
	420	3948.00	1.260	0.02112	0.93773	1885.0
μg = 0.01942	480	3985.00	1.206	0.02123	0.93940	1922.0
Z = 0.9025	540	4015.00	1.158	0.02132	0.94172	1952.0
Cg = 2.46×10^{-4}	600	4039.00	1.116	0.02139	0.94020	1976.0
Bg = 0.00496	720	4079.00	1.043	0.02150	0.94192	2016.0
J/f = 20,000 (wellbore)	840	4110.00	0.983	0.02159	0.94421	2047.0
J/f = 3700 (formation	900	4137.00	0.956	0.02167	0.94674	2074.0
	1080	4156.00	0.886	0.02172	0.94979	2093.0
	1200	4171.00	0.847	0.02176	0.94884	2108.0
	1440	4192.00	0.780	0.02183	0.95176	2129.0
	1680	4212.00	0.725	0.02188	0.95049	2149.0
	1920	4227.00	0.678	0.02193	0.95379	2164.0
	2160	4238.00	0.638	0.02196	0.95310	2175.0
	2520	4250.00	0.588	0.02199	0.95658	2187.0
	2880	4263.00	0.545	0.02203	0.95576	2200.0
	3240	4272.00	0.509	0.02205	0.95519	2209.0
	3600	4278.00	0.478	0.02207	0.95481	2215.0
	3885	4283.00	0.457	0.02209	0.95874	2220.0
		4670.00		0.02320	0.98110	

CONCLUSION

Several important conclusions can be made from this study.

TABLE 2—RESERVOIR CALCULATIONS FOR EXAMPLE 5 (PRODUCTION TEST)

DATA & CALCULATION SHEET FOR PRESSURE BUILDUP DURING AFTERFLOW

Field Report No. ______
Flow Time 7230 Mins.
Log T ______ + 2.65 = ______
P_i 4670 PSI (ISI) · P_o ______ PSI (FSI)
Pwf 2063 PSI
H 18 Ft.
Compressibility (C) 2.46 × 10^{-4}

μ = .01942 CPS
Z = Gas Deviation Factor .9025
BHT = 180 °F + 460 = 640 °R
B_g = .00496
ϕ = 8 %
T = Kh/μ $\frac{\text{md. ft.}}{\text{cps}}$

Flow Rate: Surface (Q_g) 4800000 Standard Cu.Ft./Day
Flow Rate: Barrel Equivalent (Q) 4242 Reservoir Bbls./Day

(1) Transmissibility Calculations: (Wellbore) Early Time Afterflow Curve Match

$\frac{Kh/\mu}{f}$ Wellbore = 20000 $\frac{\Delta Pf}{Q}$ = 2.2×10^{-2} Group Factor @ 894 Δp(PSI)

$f = \frac{Q\ 4242\ \text{RBPD} \times .022\ \text{Group Factor (in Match Range)}}{\Delta P\ 894}$ = **0.1044**

Compressibility Correction (Cc)

$Cc = \frac{\frac{(P1)\ Af\ 2063 + (P2)Af\ 3314}{2}}{P_i\ 4670}$ = **0.576**

fc = f 0.1044 × Cc .576 = **0.0601**

(Kh/μ) Wellbore = $\frac{Kh/\mu}{f}$ 20000 × fc .0601 = **1203** MD.FT./CPS

(2) K Wellbore = $\frac{\mu\ .01942}{h\ 18}$ × Kh/μ Wellbore 1203 = **1.30** MDS

(3) Transmissibility Calculations: (Formation)
Late Time Afterflow Curve Match After Breakaway Point

$\frac{Kh/\mu}{f}$ Formation 3700

Kh/μ Formation = fc 0.0601 × $\frac{Kh/\mu}{f}$ Fm 3700 = **222** MD.FT./CPS

(4) Permeability Calculations: (Formation)

K Formation = $\frac{\mu\ .01942}{h\ 18}$ × (Kh/μ)Formation 222 = **0.24** MDS

(5) Slope Calculations (Steady State Buildup)

$M = \frac{(162.6)\ (Q\ 4242\ \text{RBPD}) \times \mu\ (.01942)}{(K\ .24\ \text{Md}) \times (H\ 18\ \text{Ft.})}$ = **3101** PSI/LOG CYCLE

(6) Damage Ratio DR

$DR = \frac{P_i\ 4670 - Pwf\ 2063}{M\ 3101 \times \text{Log} \frac{K\ .24 \times T\ 7230}{\phi\ .08 \times \mu\ .01942 \times c\ 2.46 \times 10^{-4} \times rw^2\ 4} - 2.85}$ = **.14**

(7) Radius of Investigation Calculations (R.I.)

$R.I. = \sqrt{\frac{K\ .24 \times T\ 60}{(40)\phi\ .08\ \mu\ .01942 \times c\ 2.46 \times 10^{-4} \times 1440}}$ = **25.6** FT.

(8) Expected Production Rate After Damage Cleanup

Rate (Qp) = D.S.T. Rate (Q) ______ Mcf/d × DR ______ = ______ MCF/DAY

(9) Expected Production Rate With Stimulated Wellbore

Rate (Qp = D.S.T. Rate (Q) 4800 Mcf/d × $\frac{(Kh/\mu)\ \text{Formation}\ 3700}{(Kh/\mu)\ \text{Wellbore}\ 20000}$ = **888** MCF/DAY

*For Corrected Values Use Fc.

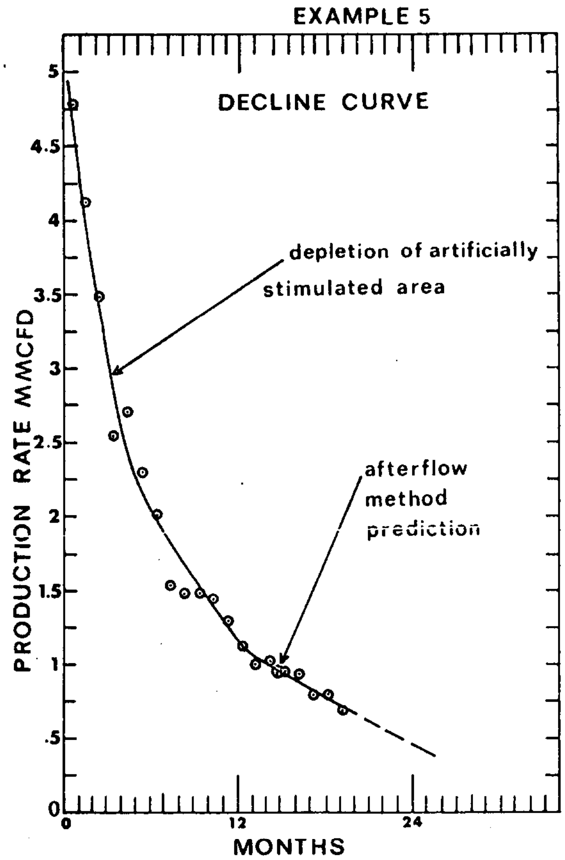

FIGURE 22

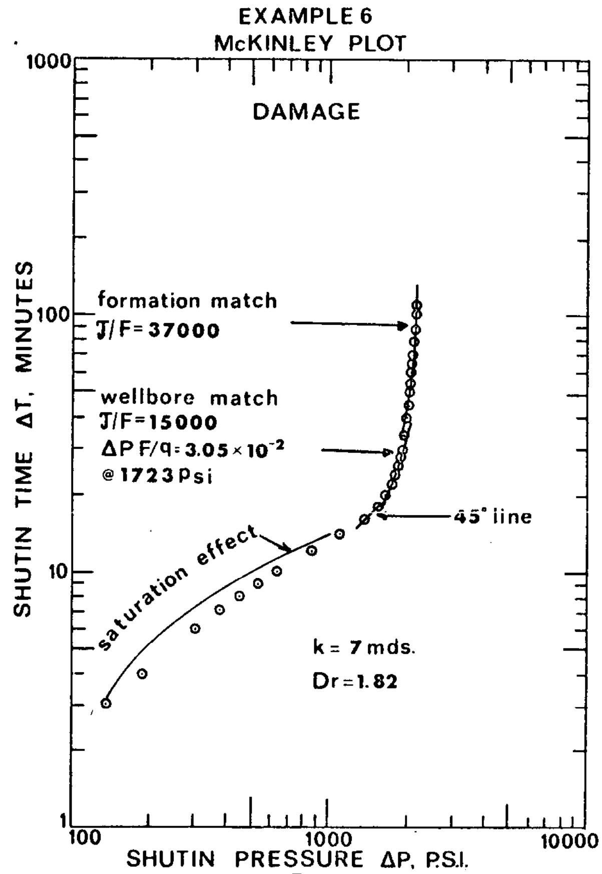

FIGURE 24

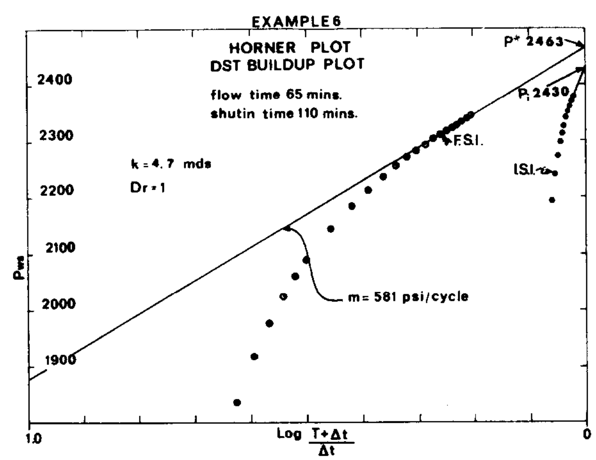

FIGURE 23

(1) The first 30 minutes of pressure buildup should be broken down into very small time increments, because much important data can be obtained from this portion of the buildup curve. Many stimulated-wellbore conditions have been observed in the first 5 minutes of buildup.

(2) Some limitations to the use of the afterflow method must be recognized, and reservoir calculations should not be attempted under certain conditions.

(3) In many cases, the afterflow plot can be used to help determine the proper portion of a conventional buildup curve to use for analysis.

(4) Wells with a naturally stimulated wellbore are usually poor candidates for artificial stimulation.

(5) The expected production rate of the matrix after depletion of a stimulated area can be predicted by the afterflow method.

(6) The afterflow method can be used to analyze buildup tests for damaged or stimulated wellbores when conventional methods cannot be used.

NOMENCLATURE

Pws	=	Buildup pressure, PSI
Pi	=	Reservoir pressure, PSI
Pwf	=	Flow pressure, PSI
ΔP	=	(Pws - Pwf), PSI
P1(af)	=	(P beginning of wellbore match) PSI
P2(af)	=	(P end of wellbore match) PSI

$\frac{\Delta Pf}{Q}$ = Pressure buildup group
T = Flow time, minutes
Δt = Shutin time, minutes
Q_L = Test flow rate, bbls/day (liquid)
Qg = Test flow rate, mcf/day (gas)
Qp = Predicted rate (bbls/day or mcf/day)
Qe = Equivalent flow rate of gas, rbpd
f = Wellbore storage factor
fc = Wellbore storage factor corrected

$\mathcal{T}$ = Transmissibility = $KH/\ \frac{\mu md.\ ft.}{cps.}$

$\mathcal{T}f$ = Transmissibility formation
$\mathcal{T}wb$ = Transmissibility wellbore
$\mathcal{T}/f$ = Transmissibility/wellbore storage factor
K = Permeability, mds
μ = Viscosity, cps
Bo = Formation volume factor vol/vol
Bg = Formation volume factor vol/vol
C = Compressibility $(psi)^{-1}$
Cc = Compressibility correction factor
ϕ = Porosity percent
Z = Gas deviation factor
T_f = Reservoir temperature, °Fahrenheit
T_r = Reservoir temperature, °Rankine
M = Slope of steady state buildup (liquid) psi/log-cycle
Mg = Slope of steady state buildup (gas) psi/log-cycle
DR = Damage ratio
R_i = Radius of investigation, ft.

REFERENCES

1. McKinley, R. M.: Wellbore Transmissibility from Afterflow-Dominated Pressure Buildup Data, *Trans. AIME,* Vol. 251 (1971).
2. Horner, D. R.: Pressure Build-up in Wells, *Proc. Third World Pet. Congr.*, Sect. 11, E. J. Brill, Leiden, Holland (1951).
3. Cobb, William M., Ramey, H.J., Jr. and Miller, Frank G.: Well-Test Analysis for Wells Producing Commingled Zones, *Trans. AIME* (1972) 27-37.
4. Matthews, C. S. and Russell, D. G.: Pressure Buildup and Flow Test in Wells, Monograph Series, Society of Petroleum Engineers, Dallas (1967) 1.

ACKNOWLEDGMENT

Test and production data for Examples 3, 4, and 5 were furnished by Henry Engineering of Midland, Texas. The followup data for the other examples was furnished by many different oil companies.