Data Acquisition and Interpretation of Horizontal Well Pressure-Transient Tests

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Summary

Using the concept of flow regimes and drawing on analogies with vertical wells, this paper reviews the pressure-transient behavior of horizontal wells. Practical guidelines are given for planning, executing, and interpreting horizontal well tests. The application of various interpretation techniques is illustrated with field examples.

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Introduction

For both vertical and horizontal wells, pressure-transient testing is a powerful tool for evaluating in-situ reservoir and wellbore parameters that describe the production characteristics of a well. Although many operators use horizontal well technology, many engineers consider pressure-transient testing of horizontal wells impractical and too complex. Experience has shown, however, that with adequate test planning, based on the concept of flow regimes and focused on optimizing test conditions, horizontal well testing can be as successful as vertical well testing. The objective of this paper is to provide the practicing engineer with guidelines for planning and executing horizontal well tests and to illustrate interpretation techniques with some field examples.

Flow Regimes in Horizontal Wells

Theoretical solutions to the horizontal well problem published in the literature[1-4] show that transient pressure data from horizontal wells may display dominant flow regimes, such as radial or linear flow, that resemble those observed in vertical wells. This is not surprising because the physics of the early-time flow behavior of a horizontal well is similar to that of a vertical well between two parallel boundaries. At later times, a vertical well with a vertical fracture is a good analogy. Theory also shows that these flow regimes can be expected to develop within specific time windows with dimensions determined by the reservoir and fluid parameters.

Flow regimes can be identified with a diagnostic plot of the field data, where the observed pressure change, Δp, and the logarithmic derivative, $p'=\mathrm{d}p/\mathrm{d}(\ln t)$, are plotted vs. the elapsed time, t, on a common log-log coordinate grid.

Consider a large homogeneous reservoir with permeabilities k_H and k_V, filled with a slightly compressible single-phase fluid. Let the horizontal well be located within a productive interval of net thickness, h, bounded by upper and lower no-flow boundaries, where the wellbore and the bedding planes are truly horizontal (**Fig. 1**). Assume that the well is put on production at time $t=0$ at a constant rate, q, and fluid entry occurs uniformly over an effective wellbore length, L_w, where $L_w \gg h$. Furthermore, assume that the pressure drop in the wellbore is negligible. **Fig. 2** shows the sequence of flow regimes that may be observed during the early phases of production. Familiarity with these flow regimes is the foundation of test planning and interpretation.

Wellbore Storage. If we ignore influx near the ends of the wellbore, fluid withdrawal will initially produce radial flow for $k_H=k_V$ (or elliptical flow for $k_H \neq k_V$) in the reservoir. Because the wellbore is not shut in at the sandface, the initial pressure response may be distorted or dominated by wellbore storage effects and therefore may not show the early-time radial flow characteristics discussed below.

For a constant wellbore storage coefficient, C, wellbore-storage-dominated flow is identified on the diagnostic plot by a collinear graph of Δp and p' with unit slope. During this period, conventional interpretation methods will yield no information about the reservoir or completion parameters. The end of the unit slope and the start of interpretable data, t_{Eus}, can be estimated from Eq. 1 in **Table 1** (see Table 1 for all equations), which is derived from Agarwal *et al.*'s[5] correlation and the traditional "rule of 50."*

The wellbore storage coefficient, C, for a wellbore filled with a single-phase fluid is calculated from Eq. 2. Eq. 3 is for a liquid with a free gas/liquid interface in a wellbore of volume per unit length, V_u, making an angle, with the vertical, θ.

The most reliable value for C is obtained from data points on the unit slope of the diagnostic plot (see Eq. 4). Although C can be much larger for horizontal wells than for vertical wells in the same formation, t_{Eus} for horizontal wells is usually not much larger because the higher value of C in Eq. 1 is offset by L_w.

Early-Time Radial Flow. On the diagnostic plot, the signature of fully developed radial (or elliptical) flow is a constant derivative, p'. A plot of p vs. $\log(t)$ will be a straight line with slope m, which yields $k_H k_V$ from Eq. 5.

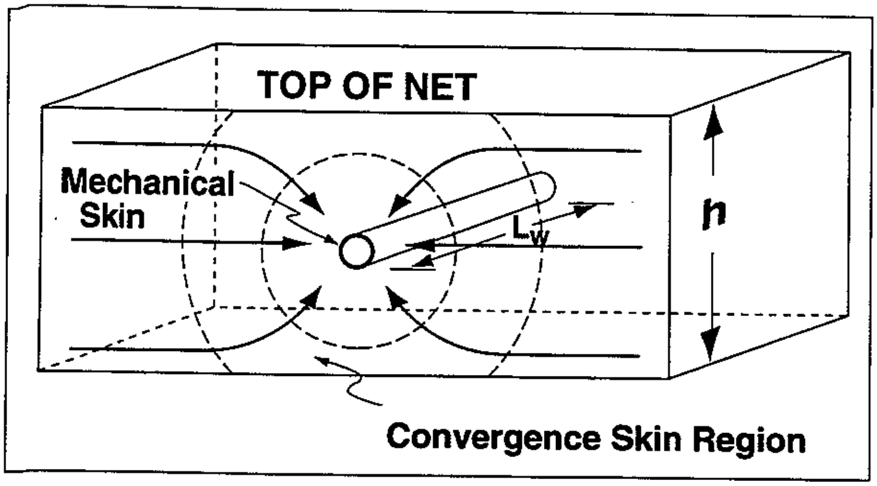
The mechanical skin factor, s_m, which is a measure of the completion quality,[7] can be calculated from Eq. 6.

Note that k_V is a macroscopic average over the depth of investigation in the vertical direction. In the presence of thin shale layers, k_V may be considerably less than values reported by core analysis. As for vertical wells, the transition period between wellbore storage and fully developed radial flow can be analyzed with conventional type-curve matching techniques. Early-time radial flow will end either when the radius of investigation reaches the nearest boundary, as given by Eq. 7, or when production from near the ends of the wellbore becomes important, as calculated from Eq. 8.[4]

Horizontal wells can also display hemiradial and pseudoradial flow periods where p' is constant. With the possibility that wellbore storage may mask early-time flow signatures, the appropriate time-window equations or simulation should be used to verify the flow period assignments. In a nonisotropic reservoir, at least one subsequent flow regime must be observed to resolve k_H and k_V.

Hemiradial Flow. When the wellbore pressure is affected by only one no-flow bound-

*Lecture notes, Raj Raghavan, U. of Tulsa, Tulsa, OK (Dec. 1982).



"For both vertical and horizontal wells, pressure-transient testing is a powerful tool for evaluating in-situ reservoir and wellbore parameters. ..."

Fig. 1—Horizontal well model.

ary, hemiradial (or hemi-elliptical) flow may develop.[6] This produces slope doubling on the semilog plot, and p' will plateau at twice the radial flow value. The $k_H k_V$ product is evaluated from Eq. 9 using the slope, m', from the semilog plot; the skin factor is calculated from Eq. 10.

Hemiradial flow will end when the radius of investigation reaches the second horizontal boundary, given by Eq. 11. It cannot develop if the wellbore is nearly midway between the two boundaries.

Linear Flow. As drawdown continues, the next flow regime encountered is linear flow. The physical description for linear flow is that the reservoir fluid streamlines become parallel to the no-flow boundaries and normal to the wellbore direction at some distance from the wellbore (Fig. 1). On the diagnostic plot, linear flow is recognized by a slope of 0.5 for both Δp and p', with p' falling below Δp. A plot of Δp vs. $\sqrt{t}$ will be linear with slope m''. Eq. 12 can be used to evaluate k_V, h, or L_w if the other two parameters are known, while the linear flow skin factor is obtained from Eq. 13.[7]

The convergence skin, s_c, is always positive and is independent of the completion quality. Linear flow will end when production from regions near the wellbore ends becomes significant at a time given by Eq. 14.[4] It cannot develop if one of the boundaries exhibits constant-pressure-type behavior, like a large gas cap.

Pseudoradial Flow. As the dimensions of the drainage area in the horizontal plane become much larger than L_w, the well enters a period of pseudoradial flow.[4] At large distances from the well, the streamlines will be horizontal and directed toward the wellbore. This situation is similar to the late-time behavior of a vertical well with a vertical fracture. p' becomes constant again and the slope, m''', of a semilog plot will yield k_H from Eq. 15, while Eq. 16 gives s_m.

Because of uncertainties in some of the parameters in Eq. 16, the pseudoradial flow period is not well suited to evaluate s_m. Pseudoradial flow starts about an order of magnitude after the end of linear flow (see Eq. 17).

It ends when lateral reservoir boundaries affect the pressure history. We choose the smaller value for t_{Eprf} as calculated from Eq. 18 or 19.

Subsequent flow regimes caused by lateral reservoir boundaries are identical to those observed for vertical wells and are not discussed here.

Note that the time window equations are approximate and some variations can be found in the literature.

Pressure-Buildup Theory

As with vertical wells, the analysis of pressure-buildup tests for horizontal wells is based on the principle of superposition. A rate change for a well is modeled by superimposing fictitious producers or injectors at a well location and adding the pressure change contributions from all wells. These fictitious wells will step through exactly the same flow-regime sequence as the original producer, delayed in time, with pressure magnitude and sign determined by the flow rate.

The shut-in of a well producing at a rate q is simulated by superimposing an injector with rate $-q$ at the producer location at the time of shut-in, t_p. Adding the two pressure contributions for wells in an infinite-acting reservoir leads to the concept of the Horner plot for radial flow or to the tandem-root plot to interpret buildup tests for linear flow. For these methods to be mathematically correct,[4] both the producer and the fictitious injector must be in the same flow regime. With the parade of flow regimes to be expected from a horizontal well, this criterion is very restrictive. Fortunately, this flow-regime condition can be relaxed if t_p is much larger than the maximum buildup time.[7] The pressure change contributions from the producer can then be neglected and buildup data can be analyzed like a draw-

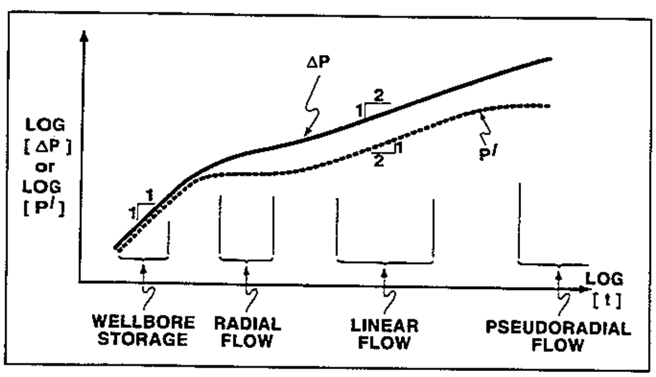


Fig. 2—Drawdown diagnostic plot for a horizontal well midway between an upper and a lower no-flow boundary.

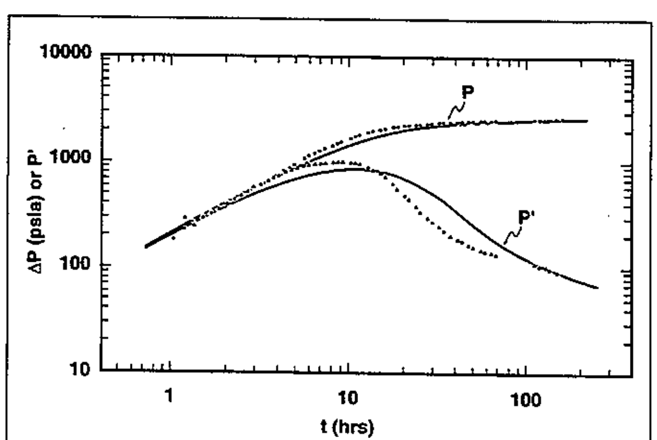


Fig. 3—Well A: buildup type-curve match.

TABLE 1—FLOW REGIME EQUATIONS

Wellbore Storage

$$t_{Eus}=\frac{(4{,}000+240s_m)C}{\sqrt{k_Hk_V}\,L_w/\mu} \tag{1}$$

$$C=V_{wb}c_{twb} \tag{2}$$

$$C=144V_u/\rho\cos\theta \tag{3}$$

$$C=qBt/24\Delta p \tag{4}$$

Early-Time Radial Flow

$$\sqrt{k_Hk_V}=162.6qB\mu/mL_w \tag{5}$$

$$s_m=1.15\left[\frac{\Delta p_{1hr}}{m}-\log\left(\frac{\sqrt{k_Hk_V}}{\phi\mu c_tr_w^2}\right)+3.23\right]+2.30\log ½\left(+\sqrt[4]{\frac{k_H}{k_V}}+\sqrt[4]{\frac{k_V}{k_H}}\right) \tag{6}$$

$$t_{Erf}=1{,}800d_z^{\,2}\phi\mu c_t/k_V \tag{7}$$

$$\text{or } t_{Erf}=125L_w^2\phi\mu c_t/k_H \tag{8}$$

Hemiradial Flow

$$\sqrt{k_Hk_V}=2(162.6qB\mu/m'L_w) \tag{9}$$

$$s_m=2.30\left[\frac{\Delta p_{1hr}}{m'}-\log\left(\frac{\sqrt{k_Hk_V}}{\phi\mu c_tr_w^2}\right)+3.23\right]+2.30\log\left[\left(1+\sqrt{\frac{k_H}{k_V}}\right)\frac{d_z}{r_w}\right] \tag{10}$$

$$t_{Ehrf}=1{,}800D_z^2\phi\mu c_t/k_V \tag{11}$$

Linear Flow

$$L_wh\sqrt{k_H}=\frac{8.13qB}{m''}\sqrt{\frac{\mu}{\phi c_t}} \tag{12}$$

$$s_m=\frac{L_w\sqrt{k_Hk_V}}{141.2qB_o\mu}\Delta p_{t=0}-s_c\ \text{where}\ s_c=\left[\frac{\pi r_w}{h}\left(1+\sqrt{\frac{k_V}{k_H}}\right)\sin\frac{\pi d_z}{h}\right] \tag{13}$$

$$t_{Elf}=160L_w^2\phi\mu c_t/k_H \tag{14}$$

Pseudoradial Flow

$$k_H=162.6qB\mu/m'''h \tag{15}$$

$$s_m=1.15\sqrt{\frac{k_V}{k_H}\frac{L_w}{h}}\left[\frac{\Delta p_{1hr}}{m'''}-\log\left(\frac{k_H}{\phi\mu c_tL_w^2}\right)+1.83\right]-S_c \tag{16}$$

$$t_{Sprf}=1{,}500L_w^2\phi\mu c_t/k_H \tag{17}$$

$$t_{Eprf}=2{,}000\phi\mu c_t(L_w/4+D_y)^2/k_H \tag{18}$$

$$\text{or } t_{Eprf}=1{,}650\phi\mu c_tD_x^2/k_H \tag{19}$$

TABLE 2—FIELD EXAMPLE DATA

	Well		
	A	B	C
L_d, ft	2,470	2,000	1,400
L_w, ft	—	—	484
r_w, ft	0.25	0.30	0.41
ϕ, %	5	17	17
h, ft	150	75	54
q, STB/D	104	200	2,760
B_o, RB/STB	1.40	1.60	1.10
μ, cp	0.45	1.80	4.88
t_p, hours	238	1,320	36

down. Therefore, a long drawdown will greatly facilitate buildup-test flow-regime identification and analysis.

Reservoir Pressure. To ensure retrieval, wireline-deployed gauges are usually set in the tubing at a depth near the kickoff point, which may be several hundred feet above the formation. Formation pressures must then be estimated from the gauge readings and an extrapolation of the pressure gradient measured above the gauge location. This is greatly facilitated if the tubing is filled with a single-phase fluid to a depth several hundred feet above the gauge location.

The average reservoir pressure, $\bar{p}$, derived from pressure-buildup tests, is considered to be an important parameter for PI and material-balance calculations. For new wells, it is recommended to measure the initial reservoir pressure directly at the end of a long shut-in following a short cleanup flow. Before significant depletion of a reservoir, $\bar{p}$ can also be obtained for radial flow by extrapolating the Horner line to infinite time; for the linear flow, the tandem root graph is extrapolated to zero time.

As the reservoir is depleted, however, these extrapolation methods become increasingly inaccurate and various corrections based on shape factors have been proposed for vertical wells.[8] Although these methods can be modified for horizontal wells, reservoir heterogeneities usually make it difficult to assess the appropriate shape factors. The problem is perhaps best approached through numerical simulation and matching of the pressure-rate history for the wells under consideration.

Reservoir Heterogeneities

Pressure-transient analysis results are the parameters for a homogeneous reservoir and uniform completion model that give the best fit to data from a heterogeneous world. If openhole logs show significant variations in the reservoir properties along the wellbore, with an appropriate completion, testing by intervals or production logging can help identify heterogeneities along the wellbore. As discussed by Kuchuk,[9] horizontal well tests from layered reservoirs may be difficult to interpret.

Test Objectives

A pressure-transient test plan must specify what reservoir and completion parameters are to be determined. In light of available geologic, drilling, and logging data, and with the preceding equations, the well-test engineer must determine which flow regimes can and must be traversed to allow evaluation of unknown parameters. This will guide the timing of well tests in the life of a well, production schedules before and during the test, and selection of downhole, wellhead, and production processing hardware. There must be consensus by all parties concerned (geologists, management, and drilling, completion, production, and reservoir engineers) regarding these objectives and planned procedures, preferably before the well is spudded but at least several weeks before a test so that flow conditions can be optimized.

Gauges

Interpretation of horizontal well tests relies heavily on trends observed in p'. Derivative graphs amplify both signal and noise in the data, and every effort must be made to optimize data quality. Only high-quality electronic gauges have the reliability and long running time required. Their high accuracies and data densities yield derivative curves with minimum scatter.

Downhole Shut-In

The purpose of downhole shut-in is to reduce wellbore storage so that the early-time reservoir signatures can be identified and analyzed. The need must be determined

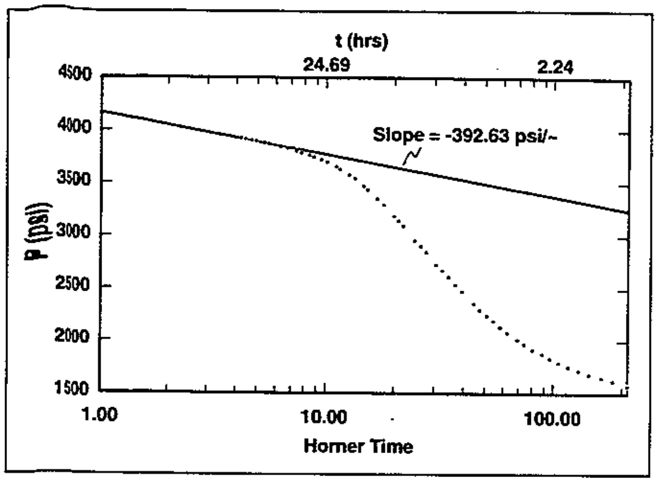


Fig. 4—Well A: Horner plot.

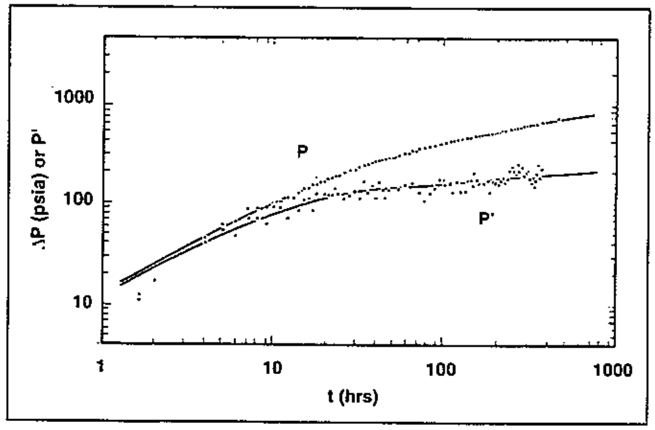


Fig. 5—Well B: buildup type-curve match.

from the time-window equations as they apply to a particular test. The greatest benefits are derived when there is gas and liquid flow in the tubing because downhole shut-in will minimize wellbore storage and phase redistribution effects. In a high-permeability reservoir with single-phase production, wellbore storage is minimal with surface shut-in. Downhole shut-in could even be detrimental to the interpretation because estimates of the distance to boundaries with type-curve matching become more inaccurate in the absence of wellbore storage effects.

Drawdown and Buildup

New wells should be tested shortly after completion. As in drillstem testing, the first step should be determining the reservoir pressure. With bottomhole gauges deployed, the well is produced for a short time to clean up the wellbore. The well is then shut in for at least five times longer than the production period. Surface readout gauges are useful to determine when pressure stabilization occurs. With the well still shut in, a gradient run must be made if pressure extrapolation to the depth of the lateral is desired.

The best pressure-transient data are obtained from a buildup test following a well-managed drawdown. Thus, every buildup test should be preceded by a carefully monitored drawdown, which would serve as a conditioning period for older wells. As noted, this period should be longer than the subsequent buildup to facilitate buildup analysis. Production should be conservative to minimize the formation of a second phase in the reservoir or in the lateral section. Flow rates should be maintained constant and monitored frequently. A gradual decline in rate is better than choke adjustments with excessive over- or undershoot. For gas wells, rates must be adequate to prevent downhole liquid accumulation. For oil wells, the rate should be high enough to minimize slugging and erratic production. On new wells, flow potential tests should be deferred until after the buildup. Although wellbore dynamics can make drawdown data noisy, bottomhole gauges should be deployed during this conditioning period to allow comparison of the drawdown and buildup responses and to provide a record of the well pressure before the buildup.

For an adequate drawdown, the buildup time required to achieve the test objectives can be estimated from time window equations in Table 1. Because there are usually more unknowns to be determined from horizontal well tests, several flow regimes must be traversed and longer buildup times are required than for a vertical well in the same formation.

Interpretation

Interpretation methods for horizontal well test data are similar to those for vertical wells. The first step is to examine the diagnostic plot for apparent flow regimes. The construction of semilog and square-root-of-time graphs for radial and linear flow periods, respectively, or type-curve matching, may yield first-order estimates for the unknown parameters. The next step is to confirm the flow-regime assignment by use of the evaluated reservoir parameters. Manual or regression matches of the data to the full-horizontal-wellbore solution with specific inner and outer boundary conditions should confirm or fine tune specialized plot analysis results. Regression may be the only tool in nonisotropic reservoirs or when expected flow regimes cannot be identified. Some caution in the use of regression is indicated because convergence to the correct parameters is not guaranteed and the covariance of variables may become significant if flow regimes are poorly developed. For example, regression cannot resolve k_H and k_V if a test is terminated in early-time elliptical flow. The two permeabilities will be resolved with increasing accuracy as the test is extended into subsequent flow regimes.

Another complexity of horizontal well testing is that more unknown variables must

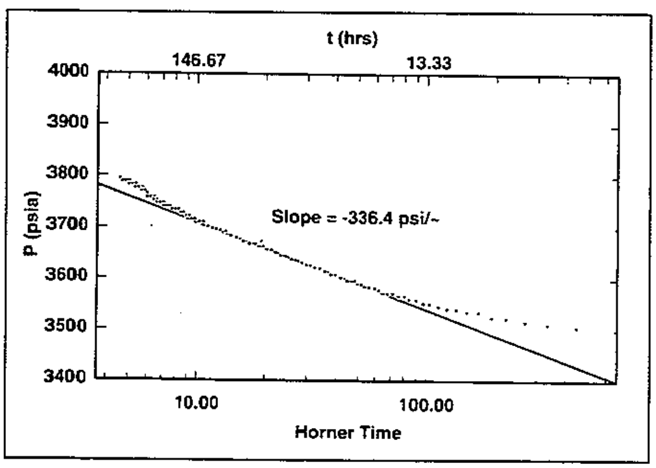


Fig. 6—Well B: Horner plot.

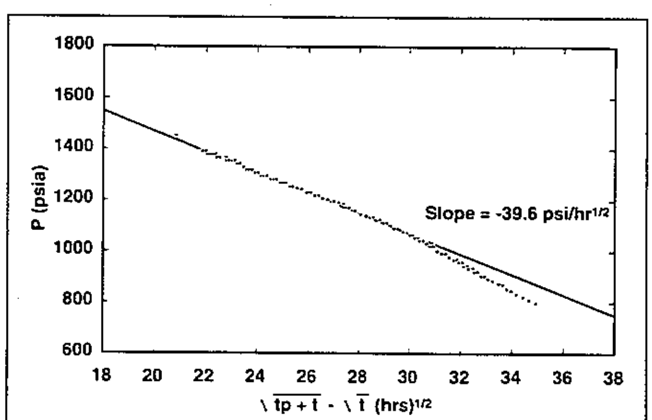


Fig. 7—Well B: tandem-root plot.

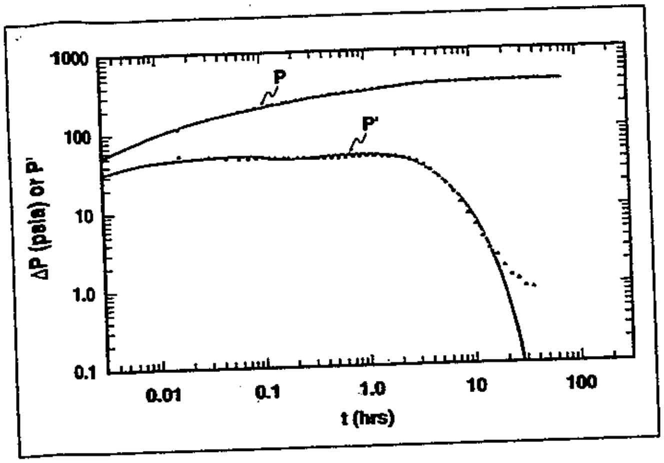


Fig. 8—Well C: regression match.

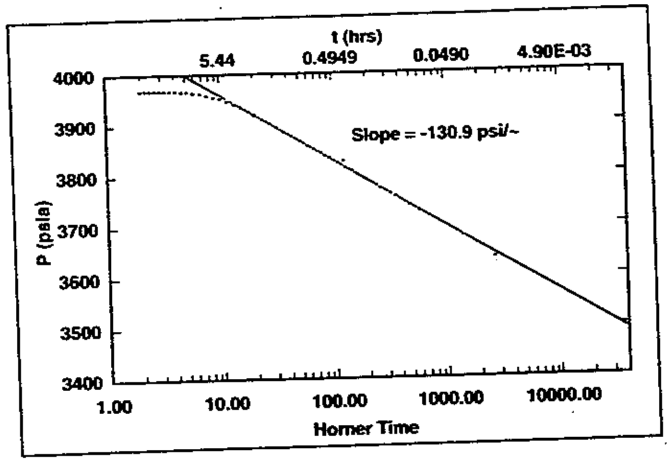


Fig. 9—Well C: Horner plot.

be evaluated. In addition to k_H, k_V, and s_m, other parameters, such as the productive wellbore length, L_w, the effective net thickness, h, and the vertical location of the wellbore within the net, may be unknown. A competent analysis will require knowledge of the geology, logging, and well survey data.

Field Examples

Table 2 summarizes the reservoir and completion parameters for the field cases.

Well A. The target for this horizontal exploration well was vertical tectonic fracture development in a low-permeability shale. Fig. 3 shows a log-log plot of Δp and p' of the data and the computer-generated buildup response. Wellbore storage is dominant during the early part of the test, followed by a transition to radial flow. Because the permeability is probably the result of vertical fracturing, the reservoir was assumed to be isotropic in the vertical plane. On the Horner plot (Fig. 4), the last few data points fall on a straight line, which yields k=0.011 md and s_m=2.9. No boundary effects are evident on the Horner plot.

Initial simulation of the data with the above parameters showed a poor match of wellbore storage to radial flow transition region. The match was improved considerably by introducing a no-flow boundary about 16 ft from the wellbore, k=0.027 md, and s_m=11.5. The remaining mismatch during the transition could be the result of phase redistribution effects in the wellbore. The distance to the no-flow boundary compares favorably with survey data, which indicated that the well was drilled about 20 ft below the upper limit of the productive horizon.

We conclude that the early-time radial flow was masked by wellbore storage and the Horner straight line is the signature hemiradial flow. From Eqs. 9 and 10, the true Horner plot permeability would be 0.022 md and s_m=8, respectively. The test was too short to detect the lower boundary, to develop linear flow, or to reveal any anisotropy.

Well B. This well is in a west Texas carbonate, which is expected to have isotropic permeability caused by fracturing and dissolution. After wellbore storage, a short period of radial flow was followed by the onset of linear flow, because both Δp and p' approach a slope of 0.5. As Fig. 5 shows, the data were matched successfully to buildup type curves for a well midway between two no-flow boundaries 72 ft apart, using k=0.15 md and s_m=−3.2. Where the derivative was relatively constant, the Horner plot (Fig. 6) yielded k=0.14 md, and a tandem-root plot (Fig. 7) gave a net thickness of 75 ft, with a distance to the nearest boundary of 29 ft. Substituting these results into Eq. 7 shows that the end of radial flow is expected at t_{Erf}=165 hours. This is in good agreement with observations and verifies the assumption of isotropic permeability.

Well C. This buildup test is from a horizontal well in a high-permeability sandstone where a 54-ft oil column overlies an extensive aquifer estimated to be about 180 ft thick. The diagnostic plot (Fig. 8) shows essentially no wellbore storage and a constant derivative, indicating radial, hemiradial, or elliptical flow at early times. The rapid decline of the derivative near the end of the test is caused by the aquifer underlying the oil column. Using the full-horizontal-wellbore solution with one no-flow and one constant-pressure boundary, regression yielded k_H=313 md, k_V=7.5 md, s_m=−1.5, and L_w=356 ft, with the no-flow boundary 11 ft above the wellbore. Eq. 7 yields $t_{Erf}\approx$1.5 hours, as indicated by the diagnostic plot. For a wellbore volume of 130 bbl and a fluid compressibility near 3.5×10^{-6} psi^{-1}, Eq. 1 gives $t_{Ews}\approx$0.0005 hours. With the gauge sampling rate set at 0.017 hours, the wellbore-storage unit slope could not be detected. The Horner plot in Fig. 9 has good linearity and gives $(k_Hk_V)^{0.5}$=53 md, which is close to the regression match value of 48 md. The large permeability anisotropy, however, makes the Horner analysis inadequate.

Conclusions

1. As predicted by theory, horizontal well buildup tests can show dominant radial and linear flow periods with characteristic signatures on the diagnostic log-log plot of Δp and p' vs. t.
2. Data from these flow periods can be analyzed with semilog or square-root-of-time graphs to yield some, but not necessarily all, of the reservoir and completion parameters.
3. Several flow regimes must be traversed to allow evaluation of all horizontal well flow parameters. Adequate drawdown and buildup times are critical for a successful test.
4. Test data should be evaluated with regression analysis to an appropriate flow model to check the specialized plot results and to evaluate remaining unknown parameters.

Nomenclature

B = FVF
c_{fwb} = compressibility of fluid in wellbore, Lt^2/m, psi^{-1}
c_t = system compressibility, Lt^2/m, psi^{-1}
C = wellbore storage coefficient, L^{4}t^2/m, bbl/psi
d_z = distance to nearest horizontal boundary, L, ft
D_x,D_y = lateral reservoir dimensions, L, ft
D_z = distance to farthest horizontal boundary, L, ft
h = formation net thickness, L, ft
k = $(k_Hk_V)^{0.5}$, L^2, md
k_H = horizontal permeability, L^2, md
k_V = vertical permeability, L^2, md
L_d = drilled length, L, ft
L_w = productive wellbore length, L, ft
m = slope of semilog plot for early-time radial flow, m/Lt^2, psi/log cycle
m' = slope of semilog plot for hemiradial flow, m/Lt^2, psi/log cycle
m'' = slope of square-root-of-time plot, m/Lt$^{5/2}$, psi/$\sqrt{\text{hr}}$

m''' = slope of semilog plot for pseudoradial flow, m/Lt^2, psi/log cycle

$\bar{p}$ = average reservoir pressure, m/Lt^2, psia

p' = logarithmic derivative, $dp/d(\ln t)$

p_{1hr} = extrapolated pressure on semilog line at t=1 hour, m/Lt^2, psi

Δp = pressure change since start of test, m/Lt^2, psi

Δp_{1hr} = $\bar{p}-\bar{p}_{t=1\ hr}$ for drawdown; $p_{1\ hr}-p_{t=0}$ for buildup, m/Lt^2, psi

q = flow rate, L^3/t, B/D

r_w = wellbore radius, L, ft

s_c = convergence skin

s_m = mechanical skin factor (completion quality)

t = drawdown or buildup time, t, hours

t_{Elf} = end of linear flow, t, hours

t_{Eprf} = end of pseudoradial flow, t, hours

t_{Erf} = end of radial flow, t, hours

t_{Eus} = end of wellbore unit slope, t, hours

t_p = constant-rate production period, t, hours

t_{Slf} = start of linear flow, t, hours

t_{Sprf} = start of pseudoradial flow, t, hours

V_u = wellbore volume per unit length, L^3, bbl

V_{wb} = total wellbore volume, L^3, bbl

θ = angle, degrees

μ = fluid viscosity, m/Lt, cp

ρ = gravitational force on liquid, m/L^{2}t^2, lbf/ft^3

ϕ = porosity, fraction

Subscript

o = oil

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SI Metric Conversion Factors

bbl	× 1.589 873	E−01	= m^3
cp	× 1.0*	E−03	= Pa·s
ft	× 3.048*	E−01	= m
md	× 9.869 233	E−04	= μm^2
psi	× 6.894 757	E−00	= kPa
psi^{-1}	× 1.450 377	E−01	= kPa^{-1}

*Conversion factor is exact.

Provenance

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