Examples of Pitfalls in Well Test Analysis

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Fig. 1 — The three flow regimes commonly modeled in well test analysis.

\[ \Delta p = p_i - p_{wf} \propto \log[t] \]

\[ \Delta p = p_i - p_{wf} \propto \sqrt{t} \]

\[ \Delta p = p_i - p_{wf} \propto \frac{1}{\sqrt{t}} \]
Fig. 2 — Behavior of a unit slope straight line on other pressure vs. time plot.

Fig. 3 — Behavior of linear flow on other pressure plots.

**Fig. 6** — Behavior of spherical flow on various pressure vs. time plots.

**Fig. 7** — Behavior of radial flow on various pressure vs. time plots.
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Summary
Recent developments in the modeling and prediction of pressure transient tests for various reservoir and flow conditions have indicated the similarities in response that may exist among totally different cases. Several case studies are used to point out pitfalls associated with force-fitting a particular flow regime or reservoir condition on a set of pressure vs. time data.

Introduction
Current diagnostic procedures used to select a reservoir flow model to interpret well tests include various plots of pressure drop or pressure recovery vs. some function of time. These plots include log ΔP vs. log Δt, log-log plot; p vs. log Δt, semilog plot; p vs. Δt1/2, linear flow plot; p vs. Δt, bilinear flow plot; and p vs. (1/√Δt), spherical flow plot.

The utility of these plots has been shown in a series of published papers during the past decades. A review of these was made recently by Ramay. 1

With the advances in analytical and numerical modeling of flow problems in reservoirs, many papers have discussed modeling the response of an idealized reservoir geometry or flow regime under the conditions of a given wellbore flow. Because of many possibilities that may exist in real situations, many investigators are working to formulate and to obtain the response in reservoirs of increasing complexity.

Real-life examples of pressure data to fit a given idealized model are often nonexistent. Consequently, many authors use synthetic data to point out the use of their proposed technique or model. In fact, practicing engineers now are reading about many techniques and models for which there may never be examples of actual data to fit. Some people may even criticize the enormous effort toward prediction of pressure response in certain idealized models.

One must note, however, that all the idealized cases published to date and yet to be published are opening our eyes to response similarities that may exist among the performance of completely different systems.

The purpose of this paper is to present a few examples, make a comparison between the responses of various reservoir models, and point out the errors in interpretation if the radial flow model is forced on the data in all cases.

Reservoir Flow Models
Reservoir geometry and K, k, are the two major factors controlling the nature of flow between the high-pressure portion of the field and the wellbore. Fig. 1 shows examples where cases of radial, linear, and spherical flow may develop. The bulk of the well testing literature is based on the assumption of a radial flow regime. Studies conducted on complex geometries, such as multilayered with or without crossflow and various wellbore and boundary conditions, have focused primarily on the main frame of a radial flow system.

The case of linear flow has been emphasized mainly for fracture-controlled flow regime. Recently, the pressure behavior in a long and narrow reservoir was reviewed. 2 Spherical flow has received very sporadic attention in the literature. 3, 4

Each of these flow regimes has its own distinct flow equation. The solution to the flow equation in the absence of wellbore effects results in a straight line on a plot of pressure vs. some function of time. The straight line is obtained for radial flow on a p vs. log Δt, for linear flow on p vs. Δt1/2, and for spherical case on p vs. 1/√Δt.

Selection of the proper flow system depends on what is known about the particular reservoir. For tests conducted during the development stages of a field, such a selection may be possible. The real difficulty is during the exploratory phase, when field data are too few to support a given model strongly.

The question addressed here is whether the formation of a straight line on a given pressure vs. time plot is indicative of the corresponding flow regime. The answer would have been easy if the straight line plots were unique. Evidence shows that pressure vs. time data for a given system may result in pseudostreamlines on two or more characteristic plots. A pseudostreamline is defined here as a trend of data points resembling a straight line on a pressure vs. time plot with no physical condition justifying such a case.

Experimentation With Theoretical Plots
Consider a set of pressure vs. time data where p=f(t) results in a straight line on given plot. The entire set or a portion of the same set may result in a pseudostreamline on other plots.

Figs. 2 through 7 show the results of experimentation with these plots. Each case starts with an assumed condition, and the graphical representations on other scales are presented.


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Fig. 5—Behavior of finite-capacity flow with skin on various pressure vs. time plots.

The case of linear flow is shown in Fig. 3. A half slope on log-log plot will result in a straight line on linear flow plot, at least partially straight line on bilinear flow plot, and curves with fractional pseudostress lines on the semilog plot. Fortunately, linear flow data on the spherical plot result in a hyperbolic curve, although there may be a tendency to fit a line through the endpoints and consider the first point of the curve as negative skin. Here, obviously, the priority must be placed on the log-log and the linear flow plot. At the same time, one must be careful not to associate a bilinear characteristic with the data since a portion of data resembles a straight line on the bilinear flow plot. Portion of a semilog plot may also be mistaken as a straight line with negative skin.

A finite-capacity fracture with a slope of 0.3 on a log-log scale is shown in Fig. 4. The use of the linear flow plot or bilinear flow plot may be misleading. Only the latter part of the data forms a straight line. Here, the combination of log-log plot and linear flow plot is very helpful to delineate the condition. Note also that the semilog plot may generate a straight line, whereas, in the absence of a log-log plot the analysis may be very confusing. The spherical plot in general shows a curvature. Similar results for a fracture with a smaller capacity are shown in Fig. 5. The bilinear plot loses its tendency to depict a straight line, but the other graphs show straight lines covering partial or complete ranges of data. This can also be seen for the spherical plot.

The case of spherical flow creates the major confusion with the semilog and the log-log plots (Fig. 6). It is possible that a portion of the data plots as a straight line on a semilog scale as well as a spherical plot. The radial flow equation may result in the formation of a pseudostress line on linear, bilinear, or even the spherical plot (Fig. 7).

From these experiments with the equations describing various flow regimes it becomes clear that the nature of the time function relationship is the main cause for observations of pseudostress lines on different plots and not the simultaneous existence of several flow regimes.

**Review of Some Guidelines**

In this section, a series of questions and answers concerning the general concepts are reviewed.

The first two questions are (1) is a unit slope on a log-log plot always indicative of wellbore storage and (2) does wellbore storage always cause a unit slope?

A unit slope on a log-log plot indicates a proportionality between the pressure change and time and is independent of formation properties. As long as the unit slope prevails, the effect is related to wellbore-storage condition. Unit slope may be absent if very early data are not recorded or if the storage goes to a series of changes because of interface movement, gas compression or decompression, phase separation, etc.

The third question is whether the skin-affected pressure data always appear after the wellbore-controlled data. Pressure drop resulting from skin may have several causes. If these causes are around the wellbore and within the formation, one would expect the skin-related effects to manifest their presence after the wellbore storage has ended. But if the pressure drop resulting from skin is because of a wellbore-related effect (such as the presence of loose debris in the hole), the effect may be evident during the afterflow.

The next question that may be asked is whether the half slope always indicates a linear flow, or does the presence of a hydraulic fracture always cause a half slope on the log-log plot?

The data points in the transition zone between the wellbore-controlled part and the portion depicting the flow in the bulk of the formation show slope reduction.
TABLE 3—PRESSURE DATA FOR CASE 3

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The log-log plot in Fig. 12 and the linear plot in Fig. 13 show a definite pseudostraight line. The linear plot also indicates a fracture with finite conductivity. A similar pseudostraight line is shown in Fig. 14 for Case 3. The linearity of the log-log plot in Fig. 15 also indicates a fracture with finite conductivity. The linear plot in Fig. 16 shows a straight line on a log-log plot for Case 3. The linear plot in Fig. 17 shows a pseudostraight line for Case 4.

Case 1. Table 1 shows pressure buildup data for a finiteconductivity fracture using the solution presented by Agarwal et al. The m(φ, ap) plot as a function of Δt is shown on various plots. The linear plot shows a definite pseudostraight line (Fig. 8). Also, the same data plotted on a spherical flow scale are shown in Fig. 9, indicating the possibility of one assuming a straight line for a portion of the data.

Here, for a case where the exact conditions were known, the possibility of other flow regimes manifest themselves in the form of pseudostraight lines.

Case 2. Pressure buildup data for a well in a long narrow reservoir shown in Table 2. Fig. 10 shows the linear plot, which indicates a fracture with finite conductivity. Fig. 11 shows that there may be bilinear flow.

Case 3. Pressure changes during a drawdown test for a well draining a two-layer reservoir are shown in Table 3. The log-log plot in Fig. 12 indicates that the second line observed on the log-log plot is linear (a fracture?) and the first part of the data suggests damage in the fracture. The linear plot may even be considered indicative of bilinear flow (Fig. 14). The spherical plot shows the possibility of a spherical flow (Fig. 15).

It is interesting to compare all the false interpretations that may develop when one considers the basis of data to be that of a two-layer system.

Case 4. Streb et al. presented several pressure buildup test data for Well 2 of their study. Consider Test

4, in which the well was analyzed by a Horner plot with no clear explanation for the second trend developing after the Horner straight line. The same data plotted in Figs. 16 and 17 show a fracture flow with finite conductivity and a bilinear flow. The bilinear flow plot covers almost the entire range of data.

Case Study 5, Raghavan and Clark analyzed the case of a spherical flow. Their data on semilog plot results in the familiar straight line associated with radial flow (Fig. 18).

Conclusion
Pressure data from a buildup or drawdown test, when plotted vs. some function of time, may produce exact or pseudolinear lines. The observation of such exact or pseudolinear does not necessarily indicate two or more flow regimes, it may be a matter of mathematical coincidence. Other reservoir data from well logs, geophysical maps, core data, outcrop studies, etc. should be consulted to verify the most relevant flow regime for the reservoir.

Nomenclature
\( k_w \) = thickness, ft [m]
\( k_r \) = radial permeability, md
\( k_v \) = vertical permeability, md
\( m(P_m) \) = gas pseudopressure function
\( q_r \) = flow rate, million cu ft/D \( [10^6 \text{ m}^3/\text{d}] \)
\( t_s \) = pseudotransient time, days
\( t_v \) = pseudosteady time, days
\( \gamma \) = gas specific gravity (air=1)
\( \phi \) = porosity, fraction

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References

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Use of the Pressure Derivative for Diagnosing Pressure-Transient Behavior

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Fig. 1 — Diagnostic plots for pressure transient test analysis (log-log and Horner (semilog) plots).
Use of the Pressure Derivative for Diagnosing Pressure-Transient Behavior

C. Ehlig-Economides, SPE, Schlumberger

Summary. The combined plot of pressure change and log derivative of pressure change with respect to superposition time as a function of elapsed time was first introduced by Rood et al. 1 as an aid to type-curve matching. Features that are hard to identify (a) on the Horner plot are hard to distinguish because of similarities between one reservoir model and another are easier to recognize on the pressure-derivative plot. Once the patterns have been diagnosed on the log-log plot, specialized plots can be used to compute reservoir parameters or the data can be matched to a type curve.

The Horner plot has been the most widely accepted means for analyzing pressure-buildup data since its introduction in 1951. 2 The slope of the line obtained by plotting pressure vs. log Horner time is used to compute the reservoir permeability. 3 The Horner plot is the log of production time plus shut-in time divided by the shut-in time. 4 The extension of this line to the time 6 hour after the start of the buildup provides a means for calculating the skin factor. 5 The extension of this line to the time when the Horner time equals 1 is the extrapolated pressure used to determine the average reservoir pressure 6-8.

Another widely used tool to pressure-transient analysis is the plot of log pressure change vs. log elapsed time. This latter plot serves two purposes. First, the data can be matched to type curves, 4,5 which are plots of analytically generated reservoir response patterns for specified reservoir models. Second, the type curves can illustrate the expected trends in pressure-transient data for a large variety of well and reservoir systems.

The visual impression afforded by the log-log presentation has been greatly enhanced by the introduction of the pressure derivative. 4,7 In practice, the derivative of the pressure change is taken with respect to the superposition time function, 4,5 which corrects for variations in the surface flow rate that occurred before the flow period being analyzed. As such, it represents the slope of the line Horner plot for buildup data. When the data produce a straight line on a semilog plot, the pressure derivative will, therefore, be constant. That is, the log-log derivative plot will be flat for that portion of the data that can be correctly analyzed as a straight line on the Horner plot.

Many analyses rely on the plot of log-log pressure vs. pressure derivative to diagnose which reservoir model can represent a given pressure-transient data set. Patterns visible in the log-log diagnostic and Horner plots for five frequently encountered reservoir types are shown in Fig. 1. The simulated curves in Fig. 1 were generated from analytical models. For each case, the log-log plot illustrates the features typically seen in real data. The curves on the left represent buildup responses; the derivatives were computed with respect to the Horner time function. The curves on the right show what the same examples look like on a plot of pressure vs. log Horner time.

For each log-log plot, the upper curve is the pressure change, ΔP, vs. the shut-in time, Δt, and the lower curve is the pressure derivative that is characteristic of a particular reservoir model; shown in a different type of line that is reproduced on the Horner plot. The portions of the derivative curves that appear flat determine where to draw the lines on the Horner plots, which are determined from a least-squares fit using the points between the arrows on the plot. When the Horner plot line has been diagnosed from the derivative response, the values computed for permeability, skin, and extrapolated pressures will be based on the radial flow response required for the Horner analysis.

The Horner plots were drawn with Horner time increasing on the horizontal plot axis. This means that the earliest data points appear to the right of the plot and the latest data point appears furthest to the left. For this reason, the flow regimes represented by different line types are reversed in order on the Horner plots.

Using common response patterns like those shown in Fig. 1, the Horner semilog straight line, wellbore storage, and skin are recognized as important features of reservoir behavior. The Horner analysis described in this section is an adaptation of the method developed by Ehlig-Economides. 1,4-8 Ehlig-Economides, C. (1988): "Use of the Pressure Derivative for Diagnosing Pressure-Transient Behavior," paper SPE 18594, Journal of Petroleum Technology, October 1988, 1260-1282.
results from dual-porosity behavior, for the case of pseudo steady flow from matrix to fractures. 19

Fig. 1 clearly shows the value of the pressure/pressure derivative presentation. An important advantage of the log-log presentation is that the transient patterns have a standard appearance as long as the data are plotted with square log cycles. The visual patterns in semilog plots are amplified by adjusting the range of the vertical axis. Without adjustment, many of the data may appear to lie on one line and subtle changes can be overlooked.

Some of the pressure-derivative patterns shown are similar to those characteristic of other models. For example, the pressure-derivative doubling associated with a fault (Example E) can also indicate transient interporosity flow in a dual-porosity system. 10 20

The sudden drop in the pressure-derivative in buildup data can indicate either a closed outer boundary or a constant-pressure outer boundary resulting from a gas cap, an aquifer, or a pattern injection well. 3 21

The valley in the pressure derivative (Example E) could indicate a layered system instead of dual porosity. 3 For these cases and others, the analyst should consult geological, seismic, or core-analysis data to decide which model to use in an interpretation. With additional data, a more conclusive interpretation for a given transient data set may be found.

An important place to use the pressure/pressure-derivative diagnosis is on the wellsite. If the objective of the test is to determine permeability and skin, the test can be terminated once the derivative pattern is identified. If heterogeneities or boundary effects are detected in the transient, the test can be run longer to record the entire pressure/pressure-derivative response pattern needed for the analysis.

Ref. 6 provides a method for computing the pressure derivative. Modern electronic gauges typically produce data that are readily differentiable and, often, data from a mechanical gauge produce an adequate derivative presentation. Hence, to avoid errors caused by analyzing the "wrong" straight line on a Warner plot or a lack in the log-log plot of pressure and its derivative is always recommended. With some experience, the analysis can readily recognize the most common transient-behavior patterns on this plot and can learn much more from each data set.

Acknowledgments

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References

Testing Design and Analysis

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Three types of well testing: Impulse, conventional and interference. Impulse testing measures the transient caused by a very brief flow, typically just as the well is perforated. Results yield skin and permeability and may indicate if remedial stimulation is required. Conventional well testing measures the shut-in transient after a lengthy flow period and is often used to detect reservoir limits. Interference testing measures the transient in a well caused by one or more flow pulses in a nearby well. Results yield details about interwell transmissivity and storativity.
\[ P(t) = \int_0^T q(\tau) p(t-\tau) \, d\tau \]

The convolution integral that converts pressure response to a unit step change in flow, \( p(t) \), and actual measured flow rate, \( q(t) \), into measured pressure response, \( P(t) \). Convolution revolutionizes transient analysis when downhole flow measurements are available, for example as measured by production logging in a flowing test. The mathematical manipulation virtually wipes out wellbore storage, leaving later portions of the transient clearly visible.
Elements of a conventional two-stage buildup transient test. Testing engineers use the first flow period to clean up formation damage and adjust the choke to gauge the producing capacity of the well. The first buildup provides a first estimate of reservoir pressure. Then begins a long flow period, followed by a longer buildup. Analysis of the transient measured during this second buildup reveals details of the near-wellbore region, formation characteristics such as permeability, and distant limits of the reservoir.

Traditional analysis centered on the Horner plot (middle), in particular the straight-line trend that signals radial flow. Today, the log-log plot (bottom) of Δp and the derivative, the slope of the Horner plot, is used to first diagnose the various flow regimes of the transient. Then, specialized plots such as the Horner plot are used to estimate specific parameters such as permeability, skin and reservoir pressure.
Reduction of wellbore storage with downhole shut-in. The log-log plot compares two well tests, one shut in at the surface, the other shut in downhole. In the surface shut-in test, wellbore storage masks the radial flow plateau for over 100 hours (4 days) (square data points). The plateau emerges clearly in the downhole shut-in data after just one hour (triangular data points).

(From Joseph et al., reference 6.)

Response of log-log plot (left column) to several common reservoir systems, showing different flow regimes (see legend). The log-log plot is used by analysts to diagnose the flow regimes present in the transient. Once regimes are identified, the Horner plot (semi-logarithmic) and other specialized plots (linear) are used to evaluate parameters characterizing the system.
Well testing is performed in so many different guises that it is easy to lose sight of its two real purposes.

of a discovery well and to maximize the cost efficiency of production in a developing or mature field. Integrated with other measurements, well tests help provide the basis of reservoir characterization.

In its simplest form, testing provides short-term production of reservoir fluids to the surface permitting the operator to confirm the show—indicated by cuttings, cores and logs—and estimate reservoir deliverability. In its subtlest form, measured pressure transient caused by almost any change in production can characterize completion damage, reservoir permeability, or distant reservoir heterogeneities.

The logistics of well testing are simple in concept, but complex in practice. Flowing an exploration well requires a temporary completion. Flowing any well not connected to downstream facilities requires heavy surface equipment including separators and flares. Obtaining pressure transients requires alternating shutting and opening the well, preferably downhole, and making accurate downhole measurements of pressure. Increasingly, testing is performed in combination with perforating and production logging to measure downhole flow. They are routinely run in horizontal as well as vertical wells.

Developing the multifaceted and intricate hardware to accomplish all these tasks is a design engineer’s dream. And juggling the many options for conducting a well test provides endless challenges in the field (see “The Nuts and Bolts of Well Testing,” page 14). This article concentrates on hardware but on the information well tests give and how tests are designed and interpreted.

Primary concerns in testing exploration wells are obtaining representative samples and estimating reservoir productivity. Fluid samples are needed to determine various physical parameters required for well test analysis, such as compressibility, and viscosity, and for pressure-volume-temperature (PVT) analysis that unlocks how the hydrocarbons phases consist of different pressures and temperatures. For oil, a critical PVT parameter is bubblepoint pressure, the pressure above which oil is undersaturated in gas and below which gas within oil starts being released. Maintaining reservoir pressure above bubblepoint is key to successful testing since the principle of transient analysis, described below, holds only if flow in the reservoir remains noncompressible. Estimating reservoir productivity requires achieving stable flow rates at several choke sizes and then determining the productivity index from the slope of the flow versus drawdown pressure data (previous page).

The type of oil at a reservoir of interest may be an additional key to producing the reservoir pressure buildup or estimate its rate. An analysis of production data from the reservoir of interest will determine the initial oil in place (OOIP), the original oil in place (OIP), and the amount of oil that can be recovered. This information will then be used to design the reservoir simulation model, which will be used to predict the recovery factor (RF) and the ultimate oil recovery (OUR) from the reservoir.

In the example shown, the initial oil in place is 1 billion barrels, the original oil in place is 1.5 billion barrels, and the amount of oil that can be recovered is 1.2 billion barrels. The reservoir simulation model will be used to predict the recovery factor (RF) and the ultimate oil recovery (OUR) from the reservoir. The recovery factor (RF) is the ratio of the amount of oil that can be recovered to the initial oil in place (OOIP), and the ultimate oil recovery (OUR) is the total amount of oil that can be recovered from the reservoir.

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The primary target is the near-wellbore region (right). The goal is to assess formation damage and, if necessary, perform stimulation. Tests last just an hour or two. In a conventional test conducted to investigate reservoir boundaries, often called a limit test, the transient time will be long enough for the pressure disturbance to reach the boundaries and then create a measurable response in the well. How long this takes depends on formation and fluid characteristics. In particular, the lower the formation permeability, the more time is needed—tests can continue for days. Longest lasting are interference tests, in which the effect of a transient created in one well is observed in another, yielding information about reservoir transmissivity and storativity.

The analysis and interpretation of well tests have evolved remarkably since the technique became established in the 1930s, today, a unified methodology has developed to obtain the maximum information from any test. The conventional test on a new well comprises two flow periods and two shut-in periods (next page). The first flow period, perhaps an hour long, is designed to clean up the near-wellbore region and give the field test crew time to manipulate changes to establish a practical, steady-state flow rate, the well is then shut in and pressure builds up to reservoir pressure, an important parameter for the reservoir engineer. Then begins a long flow period, followed by a shut-in lasting at least 1.2 to 1.5 times as long. This last step generates the transient designed to yield the reservoir’s secrets. Of course, there are many variations on these themes like "Book Well Test from the Congo," page 38.

The basic data obtained are charge in pressure, $p$, versus elapsed time since the transient was initiated, $t$. In traditional analysis, $p$ is plotted against the logarithm of $t = \Delta t/M$, a dimensionless variable in which $p$ is the duration of the flow period. This is the Horner plot—$p$ versus $\Delta t/M$ is called Horner time (next page)—and the transient is analyzed by tracing the progress of the data from right to left.

First comes wellbore storage, which refers to the obfuscating role of the wellbore fluid when a transient is initiated. The moment a well is shut in or allowed to flow, fluids in the wellbore must first compress or expand before formation fluids can react. If flow is controlled from the surface, the entire well’s fluids contribute to wellbore storage and the effect can dominate the pressure transient for hours afterward. The effect is exaggerated if well pressure toward the top of the well drops below bubblepoint and part of the well is filled with compressible gas. Wellbore storage is substantially reduced by shutting in the well downhole, minimizing the volume of fluids that contribute.

As wellbore storage dissipates, the transient begins to move into the formation. Pressure continues building up, but at a slower rate as the transient moves far enough to achieve radial flow toward the wellbore. This is the so-called radial-flow regime that appears as a straight line trend on the Horner plot. The radial-flow regime is crucial to quantitative interpretation, since it provides values for $kh$ and $S$, a measure of the extra pressure drop caused by wellbore damage. Skin takes positive values in a damaged well when pressure drop near the wellbore is greater than expected and negative values when stimulation creates less pressure drop. Next, the transient encounters the limits of the reservoir and pressure departs from its straight-line radial-flow response.

The duration of Horner time is based on a step change in flow rate, with one flow period followed by a buildup. In actual tests, there are always at least two prior flow periods, often many more, and each affects the pressure response after it occurs. Nevertheless, their cumulative effect can be determined using the superposition principle, which states that transients occurring sequentially simply add up. This results in the generalized Horner time that takes into account the flow rates and flow times for all previous flow periods. Using generalized Horner time, the Horner plot retains its validity in determining $k$ and $S$ for the most complex series of drawdowns and buildups, providing that the radial-flow regime is present in the response.

Although the Horner plot is acceptable for interpreting the radial-flow regime of easy-to-interpret tests, a straight-line trend is often difficult to pick out. Alternatively, there may be several straight-line trends, of which only one represents radial flow. Also, the plot fails to provide any insight into the nature of reservoir limits. As pressure measurements improved in accuracy, it was this aspect that increasingly engaged the attention of reservoir engineers. The solution, discovered in the early 1990s, was a double-logarithmic, or log-log, plot of two sets of data versus $\Delta t$ below (4). One set is simply $p$, the other is the gradient, or derivative, of the response on the Horner plot. The virtue of the log-log plot is that it reveals similar in construction but perhaps differing in thickness, porosity and permeability, give rise to similar looking responses and can be recognized as belonging to a class.

A pressure transient breaks into several regimes on the log-log plot, each seeing deeper than the last. The first regime typically reflects wellbore storage, during which both the pressure and derivative curves overlay and increase along a straight line of unit slope. Wellbore fluids stabilize, pressure continues building up, but at a slower rate. The derivative curve swings down, eventually flattening out as the transient moves far enough from the wellbore to achieve radial flow. Since the radial-flow regime is a straight-line trend on the Horner plot, the derivative curve on the log-log plot is constant and traces a horizontal line. The interpreter’s first task always is to identify this derivative plateau, but this may require waiting a long time in tests dominated by wellbore storage (page 34, top).

Long-lived wellbore storage can totally mask outward flow regimes that occur for certain borehole-formation configurations and formation types, causing distinct perturbations (continued on page 38).
on the derivative response. The signs are varied (next page). A partially penetrated formation produces a linear trend on the derivative curve with a slope of \(-1/2\). In wells where the formation is strongly layered or naturally fractured, the derivative tends to dip before it rises to the radial-flow plateau. If wellbore storage is not too dominating, the transient can be analyzed to pinpoint the most likely explanation.

The last regime on the log-log plot occurs when the pressure transient has travelled far from the well and encounters the reservoir or drainage-area limits. Testing theorists have worked out the transient response to a catalog of boundary geometries (right). In most cases, the transient responses alone do not offer enough differentiation to enable the interpreter to definitively establish the boundary type. The choice of the type as well as the orientation of the boundary geometry must be guided by geologic, seismic, and log data.

There are three categories: no-flow boundary, constant pressure boundary and the special case in which the test is long enough to reach all the no-flow boundaries, thus forming a closed system. Examples of no-flow boundaries include sealing faults—perhaps several of them—pinchouts, and channels. Because no-flow boundaries reflect the transient back toward the well, they cause the derivative curve to jump to a higher level. A sealing fault causes the derivative value to double. With two intersecting sealing faults, the jump is correspondingly higher. If a fault is partially sealing, the derivative curve starts to jump but then falls back to its radial-flow value.

Constant-pressure boundaries, like a gas cap or aquifer, allow the pressure transient to flatten out at the boundary pressure, so the derivative takes a nodal, which is instantly recognizable. In a closed system, pressure is completely contained within the reservoir. How this affects the \(dp\) and derivative curves depends on whether the transient is a drawdown or buildup. In a drawdown, both curves track a line of unit slope, again an easily recognizable effect. In a buildup, the derivative curve starts moving toward the line of unit slope but then goes to a noxious before reaching it, somewhat similar to the constant-pressure boundary case.

These reservoir models are simpler than nature generally allows—in reality, a mixture of responses should be expected. Thanks to the superposition principle, however, responses may be combined to produce a realistic transient response for even the most complex situation. Simulating data, though, is the easier forward task. More dif-
Using a workstation, the reservoir engineer interacts with a computer program, such as STAR Schlumberger Transient Analysis and Report and ZODIAC for Dynamic Interpretation Analysis and Computation programs, to build a comprehensive model using all the parameters found for the various flow regimes, predict what the entire transient should look like, and compare the results with the data. In this forward modeling process, the interpreter undertakes a process called deconvolution that attempts to isolate the transient from earlier ones and in particular reform the given transient's data to mimic how the reservoir would have reacted if the flow rate change had been isolated, perfect step.

Designing well tests involves many of the same steps the interpreter uses. This is because once a test has been proposed, both the pressure data and the data interpretation can be simulated to show that the test as designed meets its goals—design simulation requires estimates of formation and fluid parameters from nearby wells or the well in question. By predicting the likely shape of the log-log Ap and derivative curves, the interpreter can demonstrate the feasibility of detecting and characterizing the anticipated reservoir features. For example, design simulation ensures that wellbore storage does not smooth the feature being sought and guarantees a test that is long enough to view suspected reservoir boundaries. Another important feature of simulation is determining the accuracy and precision required of the pressure gauges.

The design phase not only maps out the mechanics of a test, but also ensures that, once underway objectives are met. For example, the progress of the planned transient can be followed at the wellsite and compared with that forecast during the design. To avoid the costly restart of a job that was going down the well before the transient indicates a desired feature, wellsite validation of data during the test remains a must. This is best accomplished with surface readout of downhole gauges and enough computing power at the surface to produce appropriate plots, notably the log-log diagnostic plot. If the reservoir response is quite different from that assumed in the design, wellsite graphics provides an instant correction of the job, perhaps a lengthening of the transient, to ensure optimum use for the data. In certain cases, real-time readout is not feasible and downhole recording must be used. Data validation must still be performed onsite right after retrieving the gauges.

Integral to well test design is selection of hardware, which involves many options. To minimize wellbore storage, should the well be shut in downslope rather than at surface? In a low producer, will the act of shutting in actually kill the well? How sensitive must the pressure gauges be? To some extent, these questions are decided by the operator's standard practices, the current status of the hole, the configuration of the downhole hardware and, of course, safety considerations.

The options have expanded in recent years. While calibrating test (DST) equipment has always guaranteed downhole shut-in in new wells, downhole shut-in devices for completed wells did not become commercial until the early 1980s. Pressure gauges have evolved from crude mechanical devices to quickly mating, highly accurate quartz gauges. Perhaps the most unexpected innovation is a downhole flow measurement.

Traditional well test theory is dispensed with a flow measurement because it assumed constant wellbore storage, enabling flow to be estimated from early pressure data. But reality is less predictable. Wellbore storage varies as the fluids in the wellbore change during the test, and a downhole flow measurement in fact offers a valuable complement to conventional pressure data.

Downhole flow measurements are currently performed using production logging...
There are several advantages to testing a well with downhole pressure and flow measurement devices under drawdown—and one disadvantage. The disadvantage that reservoir shut-in pressure is not measured. The advantages are:

- In producing wells, production is lost since the well is never shut-in.
- In producer production is not killed as easy occur during a shut-in.
- In layered reservoirs, testing under drawdown reduces the possibility of crossflow between producing layers, while this can easily occur in a buildup test complicating the interpretation.

The technique's most popular application in layered reservoirs, though, is in analyzing individual layer efficiency and skin values. This involves measuring a series of transients created by changing the production rate, one for each layer with the production logging tool situated at the top of the layer (right). The amount of data acquired is huge and can be analyzed in several ways with varying degrees of sophistication. The key, however, is to first analyze the transient measured with the tool situated above the bottom layer, yielding layer's reservoir properties. Then, a second transient is measured with the tool situated above the next layer, revealing reservoir properties of the new layer and bottom layer combined. Since reservoir properties for the bottom layer are already estimated, the transient can be analyzed to reveal just the new layer's properties. The process continues up the well.

Layered reservoir testing (LRT) was originally conceived to investigate production wells. Recently in offshore Congo, AGIP used the technique to evaluate a layered reservoir encountered by an exploration well. Conventional testing of individual pay zones in an exploration well would normally call for a separate DST-perforation run for each zone. But using layered reservoir testing, AGIP obtained reliable data skin and productivity index values for individual zones with only one trip in the hole, at a considerable cost saving (see "Exploration Layered Reservoir Testing in the Congo," next page). The drawback of using an LRT in the exploration setting is that production from different zones commingles, ruling out representative sampling from different pay zones. Fortunately, a recent technological innovation provides a solution. Samples of extraordinary reliability may now be obtained from any number of zones using the new wireline-conveyed MDT Modular Formation Dynamics Tester, but this has to be planned in advance because the sampling takes place in open hole (see "The MDT Tool: A Wireline Testing Breakthrough," page 58).

In addition to layered convolution and layered reservoir testing, there are other advantages to supplementing conventional pressure data with production logging measurements. A flow profile run during stabilized production or shut-in can pinpoint where production is coming from and provide invaluable data on crossflow between zones. The information may directly influence testing interpretation. For example, if a zone is producing only from its upper part, a portion of the transient will react as if the well were only partially completed. The diagnosis must be adjusted accordingly. The fluid density measurement in production logging also plays a role by indicating whether gas is coming out of solution, giving a warning that a test may be occurring at below bubblepoint conditions.

Perhaps the most valuable contribution of downhole flow measurements is in testing and control.
horizontal wells. Horizontal wells pose two special problems for the reservoir engineer. The first is the unavoidably large wellbore storage effect. Horizontal sections may extend for thousands of feet and cannot be isolated from the transient. The second is the more complex nature of the transient. Once wellbore storage is stabilized, three regimes possibly replace the radial-flow regime of a conventional test (right).

First is radial flow in a vertical plane toward the well, indicated by a plateau on the derivative curve on the log-log plot—this regime is termed early-time, pseudo-radial because permeability anisotropy (vertical to horizontal) actually causes an elliptical flow pattern. The second regime begins when the transient reaches the upper and lower boundaries of the producing zone and flow becomes linear toward the well within a horizontal plane. The derivative curve traces a line of slope \( \frac{1}{2} \). The third regime occurs as the transient moves so far from the well that flow becomes radial again, but this time in the horizontal plane. In some cases, the derivative curve indicates a second plateau.

Although this makes diagnosis more difficult, it also offers benefits. As in conventional testing, the first plateau gives \( k_h \) and skin, but it is now the geometric average of permeability in the vertical plane perpendicular to the horizontal wellbore trajectory, \( k_h k_v \), where \( k_v \) is the wellbore trajectory being considered parallel to the \( x \)-axis. The intermediate linear flow period gives horizontal permeability along the \( y \)-axis, \( k_v \), and the second plateau gives the average permeability in the horizontal plane, \( k_h k_v \). In theory, the three regimes together can provide a breakdown of permeability into its three components.

The key to a successful interpretation is recognizing the first plateau, not only because this alone gives \( k_h \) but also because it is the only regime that can directly provide skin. However, it is the regime most likely to get swamped by large wellbore storage occurring in a horizontal well. The key to this dilemma is either downhole shut-in, or downhole flow measurements and logarithmic convolution. Because of the length of a horizontal well’s producing zone, supplementing test data with flow profiles measured during production logging is even more crucial for pinpointing production and recognizing crossflow (see “Horizontal Well Testing in the Gulf of Guinea” page 42). Crossflow is common in horizontal wells as well as in vertical wells, particularly during a buildup test, and may seriously jeopardize interpretation. Downhole tests are therefore recommended as an insurance policy, particularly for new wells in developed fields where differential depletion may exacerbate crossflow.

The underpinnings of horizontal well testing theory are developing rapidly. Interference testing of horizontal wells is being worked out, as is the influence on the horizontal well-test response of the same range of reservoir heterogeneities and boundaries that are now well understood for conventional testing.