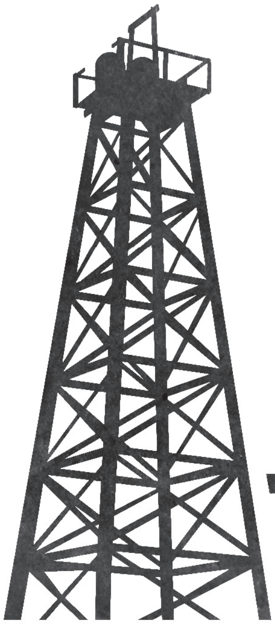
WELL TEST DESIGN & ANALYSIS



GEORGE STEWART

PennWell®

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Foreword

by Roland N. Horne

Well test analysis is one of the cornerstones of reservoir analysis, as it is only through the wells that we ever have the opportunity to make direct contact with the reservoir. Nonetheless, the reservoir parameters of importance to us are not measurable directly, hence the need to make an indirect interpretation of pressure and flow rate transients in the process we call well test analysis. The need to solve the inverse problems inherent in well test analysis makes the field one of the most intricate mathematically, while still dependent intimately on the practical characteristics and accuracy of the pressure measurements themselves.

There are few in our field who accomplish the bridge between mathematical analysis and engineering practicality as proficiently as George Stewart. He has worked centrally in the field of well testing and well test analysis for much of his professional career, starting in the 1970s when he was one of the founding faculty members at the very successful Department of Petroleum Engineering at Heriot Watt University in Scotland. In addition to advising decades of student research projects in well test analysis, George has been a key figure in the development of well testing in an industrial context. He was the principal architect of one of the earliest and most successful commercial well test analysis software packages, as well as a leading participant in the development of the wireline formation tester class of downhole tools. Additionally, by extensive active involvement in real reservoir development projects, George has accumulated a vast personal encyclopedia of practical reservoir experience, which he is able to recall in great detail. Whatever proposition may be discussed in a professional meeting, George has an example that supports (or refutes) it.

In addition to being one of giants in the field, George Stewart's personality is memorable for his generosity of spirit. Here is a man who likes to do the job right, and to help others to do the job right as well. Known throughout the industry for his good nature and generous advice, George has shared his expertise and experience with many. This book is another manifestation of his sharing.

Roland N. Horne
Stanford University
August 2010

Foreword

by Bernard J. Duroc-Danner

We view technology in the oilfield as a critical, even existential, competency at Weatherford. The convergence of accelerating decline rates, maturing reservoirs, and more complex well architecture drives this belief, and also has underpinned Weatherford's strategy for many years in our evergreen commitment to research and development.

My esteemed colleague George Stewart came to Weatherford through an acquisition in 2004 (Edinburgh Petroleum Services), which was part of this continued technology investment. With him came a plethora of both knowledge and experience in all elements of pressure transient analysis, or the science used to better understand the reservoir in conventional well testing and wireline formation evaluation.

At Weatherford, we have experienced firsthand how George's unique fusion of academic research, industrial experience, and instructional expertise has created practical, yet highly valuable, testing techniques in the various elements of our business. These include developing a new method for determining reservoir description for underbalanced drilling, as well as accelerating progress on our wireline formation testing efforts and coalbed methane well testing.

The pressure transient analysis reference series are just another example of George's unique blend of theory and practicality: the books and companion CD-ROMS provide a full exposition of the theory behind pressure transient analysis, but also offer numerous practical aspects illustrated by field examples. They also highlight George's main strength—he is not simply content to solve difficult problems. He works to ensure that he can teach others to solve them as well in ways that are easy to understand and replicate.

Sharing knowledge and best practices is essential to our industry's continued growth and health. We trust you will find the information contained in these series to be informative, accessible and useful in the much-needed ongoing requirement for better reservoir understanding.

Dr. Bernard J. Duroc-Danner
Chairman, President and CEO
Weatherford International Ltd.

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Pressure Transient Analysis in Drawdown and Buildup

Background to Transient Pressure Analysis

Introduction

One of the greatest problems facing the petroleum engineer is that of characterizing the physical nature of the subterranean reservoir from which the crude oil or gas is produced. The significance which can be put on the results of sophisticated numerical simulations of reservoir performance is entirely dependent on the quality of reservoir description inherent in the model. The difficulty in obtaining a reliable description stems from the large scale and heterogeneous nature of the reservoir and the very limited number of points, i.e., wells, at which observations can be made. In the case of an offshore reservoir, this difficulty is compounded by the fact that the well spacing is much larger than that typical of onshore operation. There are several ways by which it is possible to gain information about the reservoir characteristics; the most important are given below:

a) Seismic and associated geological studies
b) Information obtained during the well drilling programme; this comprises the following:
   1) The analysis of cuttings and cores
   2) The interpretation of various logs
c) Wireline formation testing
   1) Virgin reservoir (exploration and appraisal wells)
   2) Produced reservoir (new development wells)
d) Transient pressure testing of wells (including production logging)
e) Analysis of reservoir performance, e.g., through history matching a simulator

A consistent description of the reservoir can only be generated by collating and assessing all the available information from these different sources and synthesizing a coherent physical model of the system which minimizes inconsistencies in the data. Note that, in the reservoir which can be expanded as follows:

$$\frac{\partial(\phi\rho)}{\partial t} = \phi\frac{\partial\rho}{\partial t} + \rho\frac{\partial\phi}{\partial t} = \phi c_l \rho\frac{\partial p}{\partial t} + \rho\frac{\partial\phi}{\partial p}\cdot\frac{\partial p}{\partial t} \tag{1–12}$$

where the liquid compressibility has been denoted c_l. On defining the compressibility of the formation as

$$c_f = \frac{1}{V_p}\frac{\partial V_p}{\partial p} \tag{1–13}$$

this may be written as

$$\frac{\partial(\phi\rho)}{\partial t} = \phi\rho\left(c_l + c_f\right)\frac{\partial p}{\partial t} \tag{1–14}$$

Although in reality the ϕ on the right-hand side of Eq. (1–14) is still a function of pressure, as a first approximation it can be treated as a constant, evaluated at some representative average formation pressure. In this form Eq. (1–14) adequately allows for the small effect of rock compressibility in all but the most exceptional circumstances.

A further refinement of Eq. (1–14) is warranted; in an undersaturated reservoir two liquids are in fact present—oil and immobile connate water—both of which are compressible. Hence the liquid compressibility c_1 is given by the sum of two contributions:

$$c_1 = S_{wc}c_w + S_o c_o \tag{1–15}$$

where c_w and c_o are the compressibilities of water and oil, and S_{wc} and S_o are the respective saturations. Thus, the compressibility c in the basic Eq. (1–11) is identified with the total system compressibility c_t, which is defined as

$$c_t = c_1 + c_f = S_{wc}c_w + S_o c_o + c_f \tag{1–16}$$

Note that the permeability k in Eq. (1–11) is not the absolute permeability of the porous medium but the permeability to oil at the connate water saturation, i.e.,

$$k = k_o\,(S_{wc}) \qquad \text{(the end-point permeability).}$$

Since the flow model assumes horizontal flow the permeability also refers to this direction, i.e., it is the radial permeability. When the total compressibility c_t is employed, the density ρ refers to the mass per unit pore volume of oil and connate water.

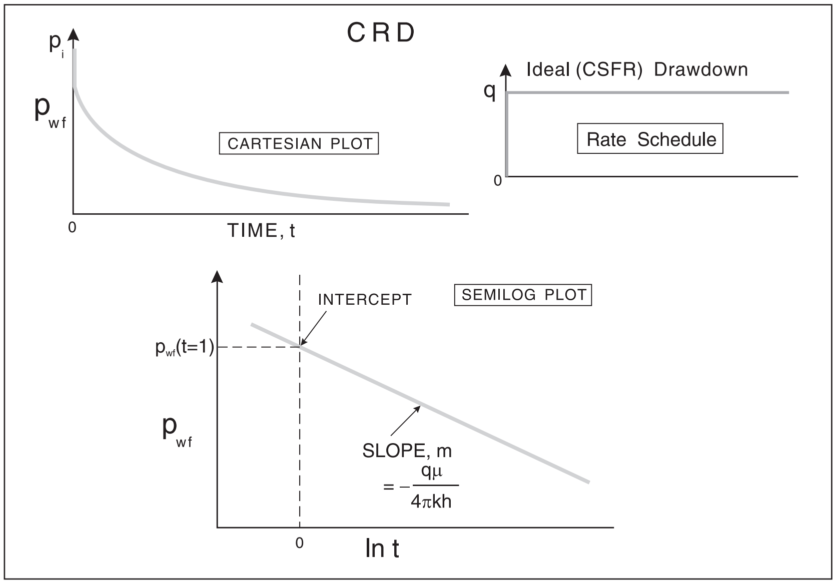

Fig. 1–14. Ideal constant sandface rate drawdown

Analytical solution for the case of a bounded circular reservoir

Of course, no real reservoir is infinite in extent and the solution of the preceding section is only valid while the pressure transient is confined within the limits of a particular cylindrical volume. As soon as the pressure at the outer boundary starts to deviate from the initial value, one of the external boundary conditions becomes operative. Usually, the alternative form most consistent with physical reality is the no flow constraint (1–29). Occasionally, the mathematical boundary may coincide with a physical barrier, i.e., the extremity of the reservoir. However, a much more common situation arises when several producing wells, placed more or less symmetrically, are distributed over the reservoir. In this case no flow boundaries arise because of the reservoir drainage patterns which develop; deviation from the transient, infinite reservoir solution occurs when the expanding, radially symmetric pressure disturbances from adjacent wells first come in contact. The concept of drainage volumes will be taken up in detail later.

In the meantime, an individual well will be assumed to be located in the centre of a cylindrically shaped drainage area of uniform thickness h and external radius r_e with no flow across the external boundary. The dimensionless differential system now takes the form

$$\frac{\partial p_D}{\partial t_D} = \frac{1}{r_D}\frac{\partial\left(r_D \frac{\partial p_D}{\partial r_D}\right)}{\partial r_D} \qquad 1 \geq r_D \geq r_{De} \tag{1–66}$$

$$t_D < 0, \quad P_D = 0 \qquad \text{all } r_D$$

$$r_D = 1, \quad \frac{\partial p_D}{\partial r_D} = -1 \qquad \text{all } t_D > 0$$

and the corresponding equation in actual variables and parameters becomes for SSS flow

$$p_{wf}(t) = p_i - \frac{q_S B\mu}{2\pi kh}\left[\frac{2kt}{\phi\mu c_t r_e^2 2e} + \ln\frac{r_e}{r_w} - \frac{3}{4} + S\right] \qquad \textbf{(1–98)}$$

where

$$p_{wfD} = p_D(1-,t_D) = \frac{p_i - p_{wf}}{\dfrac{q_S B\mu}{2\pi kh}}$$

The pressure distribution in the reservoir during the SSS period is illustrated in figure 1–22 where the stabilized shape of the pressure profiles at successive times is apparent.

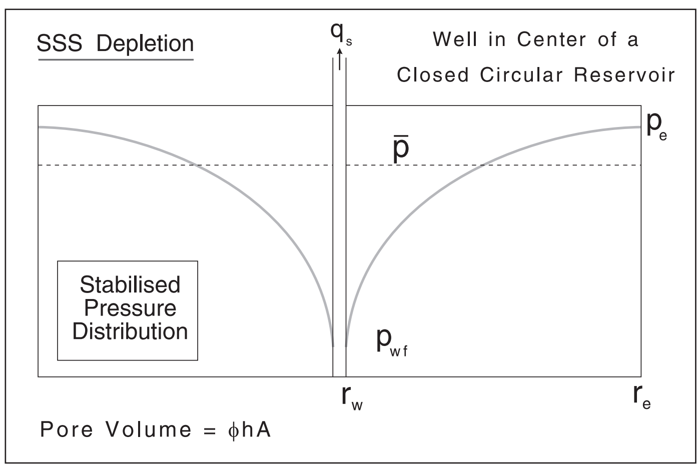

Fig. 1–22. Stabilized pressure distribution in SSS

Pressure Drawdown Testing

Introduction

The analytical solution to the diffusivity equation for a uniform pressure initial condition and a constant flow-rate inner boundary condition has led to an expression for the dynamic wellbore pressure behavior of a model reservoir having homogeneous formation permeability and instantaneous skin effect. The objective of a well test is to measure the dynamic response of an actual reservoir under these same conditions and determine unknown reservoir parameters by inference. The two most important such parameters are the permeability thickness product kh and the skin factor S. The productivity of a well can only be predicted if these quantities are known. The problem of well testing is essentially one of parameter estimation in which the unknown

One advantage of a modern electronic pressure transducer, with a high sampling rate, is that the last flowing pressure, $p_{wf}(\Delta t = 0)$, can be accurately determined as illustated in figure 1–35; this is important for the calculation of the skin. Note that the clock time corresponding to $\Delta t = 0$ (the point at which the valve actually closes) can also be accurately bracketed. Precise estimates of pressure and time at $\Delta t = 0$ are necessary for the log–log diagnostic plots discussed in the next chapter. The analysis of a buildup by the CRB method can be carried out even when the rate is varying during the drawdown period as shown in figure 1–35. The equivalent constant rate drawdown time is defined as

$$t_p = \frac{Q}{q} \tag{1–149}$$

Here, Q is the cumulative volume produced over the whole flow period and q is the last, stabilized rate. This approach should not be used when there is a strongly declining rate in the flowing period, as in a slug (rising liquid level) test; in this case full superposition is necessary as described in chapter 5.

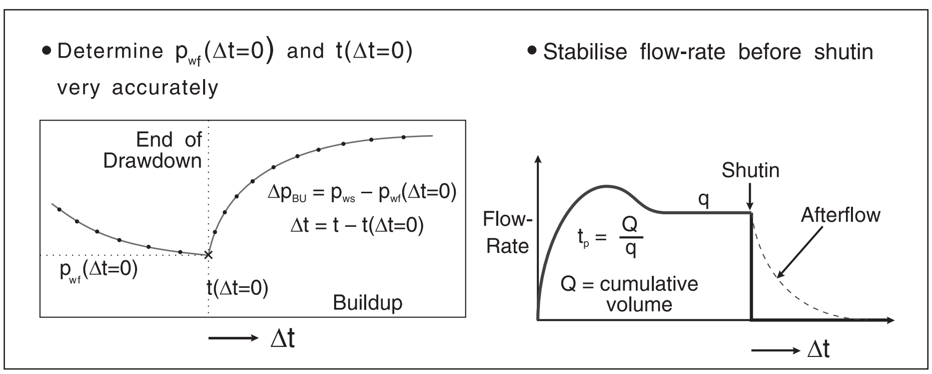

Fig. 1–35. Test precautions

In figure 1–36, a typical chart from the original Amerada gauge is depicted and it can be seen that during the flowing periods the bottom-hole pressure is actually increasing. This is the rising liquid level phenomenon apparent in many old DSTs and Horner analysis of the final buildup is not really recommended because of the implied rate variation. In 1976, the Hewlett-Packard company introduced the first quartz crystal pressure transducer and this proved essential for the satisfactory conduct of well tests in the high permeability North Sea basin. In figure 1–37, a Horner plot of a pressure buildup in a Piper (Occidental) well is shown where the total pressure change in the buildup (Δp_{BU}) is less than 5 psi; it is immediately apparent why a high-resolution pressure gauge is necessary in this application.

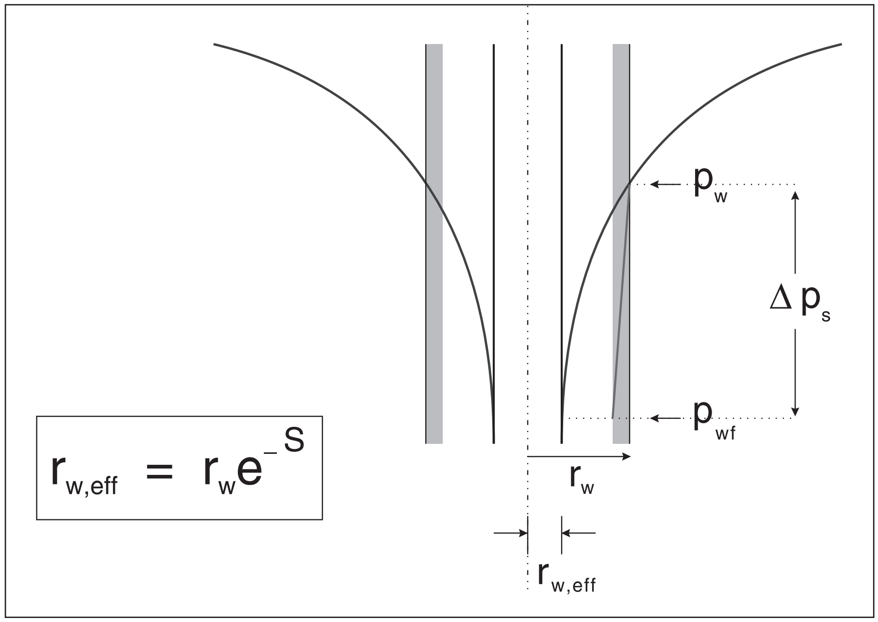

Fig. 2–10. Effective wellbore radius

The quantity $C_D\mathbf{e}^{2S}$ is simply a dimensionless wellbore storage coefficient based on the effective wellbore radius: thus,

$$C_D\mathbf{e}^{2S} = \frac{C_S}{2\pi\phi hc_t r_w^2} \cdot \frac{r_w^2}{r_{eff}^2} = \frac{C_S}{2\pi\phi hc_t r_{eff}^2} \qquad \textbf{(2–44)}$$

Gringarten showed that the $p_D(C_D, S, t_D)$ information generated from the model represented by Eq. (2–29) could be presented as a family of curves of p_D versus t_D/C_D, each one characterized by a value of the parameter $C_D\mathbf{e}^{2S}$.

The improved log–log type curve is shown on figure 2–11; it contains exactly the same information as the p_D versus t_D type curve only presented in a different manner. This $p_D - t_D/C_D$ type curve is used in the same manner as described previously. The test data are plotted as Δp versus t on a log–log graph of the same size as the type curve, i.e., compatible scales as indicated in figure 2–12a. This is then overlain and moved orthogonally, i.e., axes of both plots exactly parallel, until the best match is obtained as shown in figure 2–12b. A match point is then chosen as in figure 2–12c giving the following correspondences:

Pressure match:

$$[p_D]_M = \frac{2\pi kh[\Delta p]_M}{q\mu}$$

i.e.,

$$kh = \frac{q\mu[p_D]_M}{2\pi[\Delta p]_M} \qquad \textbf{(2–45)}$$