Selecting Wells for Stimulation

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INTRODUCTION

The stimulation of wells to increase the productivity has had wide acceptance in the industry in the last few years. The results have generally been beneficial, but, as in most processes, the method is not a cure-all, since in many instances the remedial operation has failed to produce the desired results.

It is the responsibility of field managers and engineers, at any time, to avoid spending money on projects which will not be profitable. With limited funds available in depressed economic times, it is most important that such funds be spent on those projects with best prospects of maximum return.

To aid the engineer and manager in selecting such projects, bottom-hole pressure buildup data, in many cases, have been of value. The analysis of these data is discussed using three approaches with examples of each method.

PRESSURE BUILD UP EQUATIONS

The pressure distribution in a homogeneous, horizontal reservoir of uniform thickness is described by the well known partial differential equation of motion, provided the fluid obeys Darcy's law and its compressibility and viscosity remain essentially constant over the pressure and temperature ranges of the reservoir, and its density follows the exponential type law. In applying this to pressure buildup in a well, D. R. Horner proposed use of the so-called "point-source" solution of this differential equation, which is

$$Pw = Ps + \frac{q\mu}{4\pi k h} \left\{ Ei\left(- \frac{rw^2 f \mu c}{4 k(t+\Delta t)} \right) - Ei\left(- \frac{rw^2 f \mu c}{4k \ \Delta t} \right) \right\} \quad (1)$$

Since the value of the function $Ei(-x)$. is approximately equal to $(\ln x + .5772)$ for large values of Δt, Equation 1 can be written in its approximate form, using oil field units, as

$$Pw = Ps - \frac{162.5 q\mu}{B k h} \log \left(\frac{t + \Delta t}{\Delta t} \right) \ldots\ldots (2)$$

where: Ps - static pressure, psi
Pw - well bore pressure, flowing, psi
q - production, bopd.
k - permeability, millidarcys
h - height, feet
μ - viscosity, centipoises
B - formation volume factor
t - flowing time, hours
Δt - shut-in time, hours

Use of this equation assumes that the well is in an infinite reservoir and that the well radius is negligible. It also assumes that the production, q, is constant for time, t, a condition which is seldom satisfied. It is suggested by Horner that time, t, can be approximated by dividing the total cumulative production during the test by the last established production rate.

This calculated time shall be designated by tc. We may write then

$$Pw = Ps - \frac{162.5 q\mu}{B k h} \log \left(\frac{tc + \Delta t}{\Delta t} \right) \ldots . (2a)$$

The well pressures during flowing time, tc, and shut-in time, Δt, when plotted against the log $\left(\frac{tc + \Delta t}{\Delta t} \right)$ will describe the buildup of pressure. Extrapolation of this curve to infinite shut-in time ($t = \infty$) should give static bottom-hole pressure, Ps.

In a limited reservoir, or in a reservoir from which a large volume has been produced, the extrapolated pressure will be too high. In such cases, the extrapolated pressure may be corrected to actual static pressure by the method suggested by Horner.

The pressure drop per log cycle from the straight line buildup curve, i.e., its slope, Z, can be read directly from the plot of the data. The transmissibility of the formation, k h, can be computed from

$$kh = \frac{162.5 Q\mu B}{Z} \ldots\ldots (3)$$

If the height, h, is known, the permeability, k, can easily be computed. This permeability is the average reservoir permeability. It is not this value that is of interest here, but the permeability immediately around the well bore which may be reduced due to completion damage. This damage is reflected in the non-linear portion of the build-up pressure curve.

Van Everdingen described the reduction in capacity of a well as being the result of a phenomenon which he called "the skin" rather than a permeability change.[8] From the "point-source" equation, he developed the solution to be

$$P_s - P_f = \frac{70.6 q\mu}{B k h} \left[\ln \frac{T + \Delta T}{T} + 0.809 + 2S \right] \ldots (4)$$

where: T = dimensionless flowing time = $\frac{4 kt}{f\mu c r_w^2}$

ΔT = dimensionless shut-in time

SELECTING THE WELL

Before using pressure buildup data for the selection of wells for stimulation, the causes of reduced productive capacity should be examined. From the foregoing discussion, it is obvious that one is damage to the formation around the well bore. A second could be a loss or depletion of reservoir pressure.

Common sense tells one that, in the latter case, no stimulation technique will be able to increase productivity. A low static pressure should be immediately obvious from extrapolation of the buildup curve to infinite shut-in time.

Evaluation of formation damage will be of prime concern in deciding which wells should be selected for stimulation. As a general rule, then, it can be stated that the well with the greatest damage should respond best to such stimulation, all other factors being equal.

Several methods have been suggested for this damage evaluation. 3, 4, 5. Solution of the van Everdingen equation (Eq. 4) for S would do this. This would not be considered here because it requires a knowledge of well bore radius, fluid compressibility, and porosity. This does not imply that it is not a good method. Examples of its application to acidizing and reperforation are given in the original paper.

Two methods for evaluating damage are those of Thomas and Arps, both of which are simple, rapid, and adaptable to field conditions.

Thomas, using the "point-source" solution of the flow equation as given by Horner, takes the average productive capacity, Eq. 3, and combines it with the radial flow formula to give the damage factor (DF) which is

$$DF = 1 - \frac{2Z \log re/rw}{P_s - P_f} \quad ....(5)$$

The factors, Z, P_s, P_f, are all obtained from the building curves as previously described. The reservoir and well radii must be obtained from other sources. A large value of DF, approaching unit, indicates high damage.

Arps suggested that this damaged area could be characterized by a "Completion Factor" (CF) which he defined as the percentage of the theoretically possible productivity which actually has been obtained. The equations for this are, for solution gas drive reservoir,

$$CF = \frac{\text{theoretical drawdown}}{\text{actual drawdown}}$$

$$= \left[2 \log (0.6065)\ re/rw\right] \frac{Z}{P_s - P_f} \quad .... (6a)$$

and for undersaturated reservoirs

$$CF = \frac{(0.001421\ k\ t)}{f \mu c\ r_w^2} \left(\frac{Z}{P_s - P_f}\right) \quad ..... (6b)$$

where: t - shut-in time, minutes

r_w - well radius, inches

c - compressibility, psi^{-1}

Solutions of these equations are easily obtained by a graphical procedure which will be explained in the example problem.

In general, the samller valued CF is, the greater the damage is. It is related to the Thomas damage factor by

$$CF = (1 - DF) \times 100 \quad .... (7)$$

EXAMPLE PROBLEM

To illustrate the methods of evaluating wells for stimulation consider a hypothetical well A that is completed in a 10 feet thick sand. The oil has a viscosity (μ) of 10 centipoises. Formation volume factor (B) is 1.1. Production is 5 barrels of oil per day.

A buildup test is conducted as follows:

1. The well is flowed for several days until a constant rate of production is established.
2. Bottom-hole pressure is measured throughout the flow period.
3. Shut-in well, recording bottom-hole pressure during period.
4. Plot pressures against the logarithm of ($t/t + \Delta t$), using semi-logarithm paper.

The results of the buildup test on Well A (Fig. 1) indicate that the decline in production is not due to a decline in formation pressure. Extrapolation of the straight-line portion of the curve to infinite shut-in time gives a static pressure (P_s) of 1500 psi.

To evaluate the loss of productivity due to damage, by the Thomas method, the slope of the curve, Z, is determined by taking the pressure difference over one cycle. This gives Z of 12 psi/cycle. Assuming a radius of 660 feet and a well radius of 3 inches, the damage factor (DF) is 0.676. This means that 67.6 per cent of the pressure draw-down is required to overcome the effects of the damaged zone.

Calculation of the Completion Factor (CF), graphically, is illustrated on Fig. 1. Stepwise this is as follows:

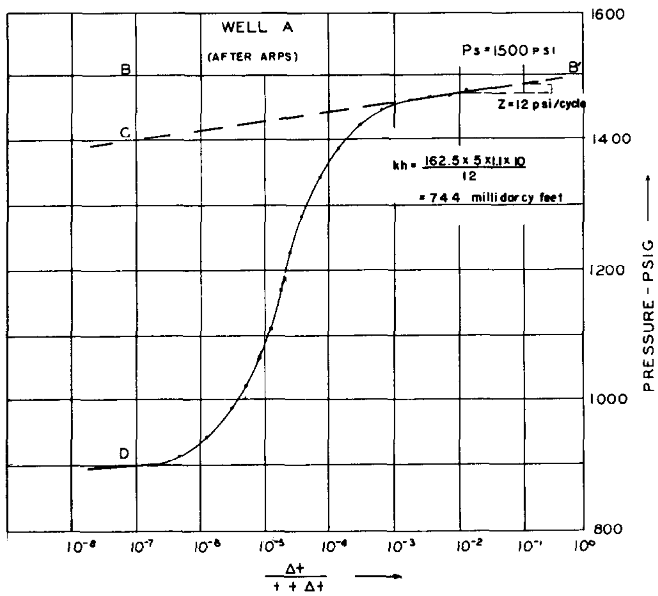


FIG. I - PRESSURE BUILD UP CURVE

1. Draw the horizontal line, B-B, through the static pressure, P_s.
2. Extrapolate the straight line portion of the buildup curve to the left a distance of n cycles. Average value of n is 6. A more precise value can be calculated by setting it equal to the logarithm of the time term in Equation 6b.
3. The vertical distances at this point represent the actual draw-down (B-C) and the theoretical draw-down (B-D).

The value of the completion factor (Eq. 6a) is 16.6 per cent.

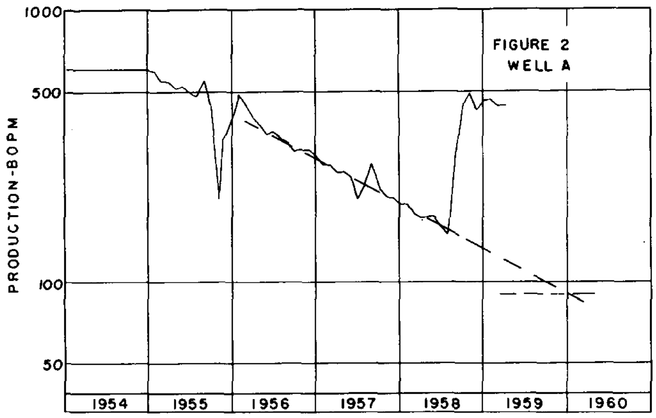
The difference between the damage factor as calculated and the damage factor using Equation 7 is the result of the assumption of the radius, r_e. It appears as though the radius is about 3500 feet, instead of 660 feet.

Both methods indicate the well productivity should be improved by a stimulation treatment. The selection of Well A over a second well with similar productivity would depend on a comparison of the two CF's or DF's.

EVALUATION OF STIMULATION

An increased production rate following stimulation is not necessarily an indication of increased profit, although the expense may be paid out in a reasonable length of time. Therefore, the recommendation to stimulate a well must be based upon factors besides the damage evaluation. Usually, the profitability will be predicted on similar, successful jobs. The success of a job can be determined by an analysis of the future production after stimulation.

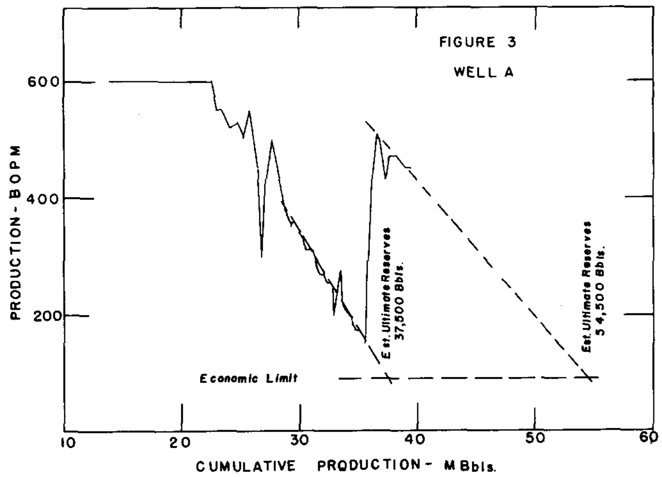
To illustrate this point, assume that Well A was hydraulically fractured after the above buildup test. The production history indicates the increased production, Fig. 2.



This does not indicate, however, that the job increased the ultimate recovery from the well. When the production rate is plotted against cumulative production, Fig. 3, and the new decline is extrapolated to the economic limit, it is seen that the recovery was increased from 37,500 barrels to 54,500 barrels. Therefore, the stimulation of Well A should be an economic success.

SUMMARY

Bottom-hole pressure build up tests can be used, in many cases, to determine if a well is susceptible to stimulation by applying the damage factor, completion factor, or similar methods. To be successful, the job must result in not only an increased rate of production, but also in a reasonable pay-out period and in an in-



creased ultimate recovery. Production records before and after the stimulation must be analyzed to indicate the success or failure of each job. The production rate-time and cumulative production curves are forms which are easily analyzed.

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