A Comparison of Theoretical Pressure Build-Up Curves with Field Curves Obtained from Bottom-Hole Shut-In Tests

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ABSTRACT

Interpretation of pressure build-up data obtained in the conventional manner has often been difficult because of the deviation from theoretical behavior. Major causes of this deviation have been attributed to damage and afterflow, and to fluid redistribution in the wellbore which, in extreme cases, can result in a pressure hump in the early portion of the build-up curve.

Theoretical investigations show that bottom-hole pressure is definitely influenced by phase redistribution in the tubing column during surface shut-in tests, and that the magnitude of the effect is sensitive to the producing gas-oil ratio and stabilized rate of flow in the well.

For field experiments a wire-line tubing packer, which can be run in the tubing against a stabilized flow rate, was developed for bottom-hole shut-in tests. By use of this bottom-hole shut-in method, pressure humps previously observed in surface shut-in tests were completely eliminated and the effects of afterflow minimized.

Analog and digital computer studies have been made to obtain theoretical curves for comparison with field curves, and remarkable agreement between the results of bottom-hole shut-in tests and theoretical curves has been obtained.

INTRODUCTION

Pressure build-up data from shut-in wells have been used by the petroleum industry to determine the permeability of the formation, to estimate wellbore damage, to evaluate the static reservoir pressure and to speculate reservoir volume. Calculation of these factors is based on methods of analysis developed for theoretical systems whose build-up curves have a characteristic shape when the wells are shut-in at the sand face. However, field curves obtained by conventional surface shut-in methods do not always exhibit this characteristic. Such factors as stratification, rock heterogeneities and irregular reservoir geometry can cause the character of a build-up curve to deviate from that predicted by theory for a simple system. In addition, all field build-up data are affected by the methods utilized in obtaining the measurements.

Conventional surface shut-in techniques allow two effects to occur which contribute directly to the manner in which pressure builds up at the sand face. The first, afterflow, has been recognized for some time and methods are available for estimating the magnitude of its effect and for correcting its influence. The second, phase segregation in the tubing column after shut-in, has been reported only recently and appears to exert a considerable influence on the character of field build-up curves. In extreme cases, phase segregation can produce “pressure humps” in the early portion of the build-up curve. Such curves have been considered anomalous and have defied analysis.

It is the purpose of this paper to discuss the effect of phase segregation in the tubing string during build-up and to present a bottom-hole shut-in technique for obtaining field build-up data which minimizes the influence of afterflow and eliminates phase segregation effects. It will be shown that reliable reservoir information can be calculated from build-up measurements obtained using this method, even though conventional surface shut-in tests on the same wells yield anomalous data.

DISCUSSION OF PHASE REDISTRIBUTION EFFECTS

Some of the effects of phase redistribution on pressure build-up curves have been described previously by Matthews and Stegemeier, who have presented evidence that phase segregation is responsible for the pres-
sure hump on many build-up curves. Undoubtedly phase redistribution occurs in most surface shut-in tests, but the conditions under which a hump may occur are not completely understood. In order to better understand these effects, the pressure rise resulting from fluid redistribution after shut-in has been analyzed theoretically using a medium-sized digital computer.

In this study the energy content of gas and oil in a given length of tubing was computed for various flow rates and producing gas-oil ratios. By assuming the tubing string to be shut-in at the surface and at formation depth, the pressure change associated with the phase redistribution of the gas and oil contained in the tubing was calculated. It was readily seen that in many cases the pressure rise at the bottom of the tubing string, resulting from fluid segregation, was of sufficient magnitude to materially affect the build-up curve. The degree of pressure rise from phase segregation was found to be sensitive to the rate of production and to the producing gas-oil ratio of the well. At low ratios the effects of fluid segregation are apparently most significant. As the producing gas-oil ratio increases, the flow of fluid in the tubing approaches that of a gaseous system, and segregation effects are minimized. At very low rates and highGOR, however, the effects of liquid hang-up, or slippage, become very important. Indications are that fluid slippage in the tubing greatly increases the effects of phase redistribution.

Fig. 1 is a field example of the effects that changing wellbore and flowing conditions can have on the character of a build-up curve. This Gulf Coast well, which has been a prolific producer, is 8,300 ft deep, contains a production packer, and has 20 ft of oil sand perforated through the casing with 80 shots. Permeability of the formation is in excess of 200 md. In Sept., 1950, two build-up tests were made in this well after stabilization at the rates of 426 and 256 B/D. Ratio of the well at the time was 570 cu ft/bbl. Both tests showed a marked influence by phase segregation, with the lesser rate showing the least influence.

In May, 1951, an additional test was made after stabilizing at a rate of 300 B/D, and the influence of phase segregation was found to be diminished. At that time theGOR had risen to 1,350 cu ft/bbl. In April, 1958, additional pressure build-up tests at 250 B/D were performed which were not so obviously affected by phase segregation. The GOR of the well at this time was 2,500 cu ft/bbl. These results are qualitatively consistent with those found in the phase redistribution study.

It appears that pressure build-up data obtained from wells with damage and production packers are more subject to the influence of phase segregation. In the case of a damaged wellbore, the pressure rise at the bottom of the tubing created by fluid segregation cannot be transferred readily to the producing formation. As a result the influence of phase segregation becomes more significant on the bottom-hole pressure measurements. Without a packer in the well, the volume and total compressibility of the wellbore is greatly increased and the pressure rise associated with fluid segregation in the tubing is more readily absorbed. At the same time, however, afterflow of fluids from the formation into the wellbore is maximized. Either one or a combination of these effects may produce a misleading build-up curve. It seems reasonable to conjecture that phase redistribution effects are more pronounced in deeper wells since larger volumes and longer times are involved in the segregation of the fluids. With these many complications it is doubtful that an adequate calculatory procedure can be developed to correct for the combined wellbore effects.

**BOTTOM-HOLE SHUT-IN TOOL**

To eliminate fluid segregation effects and to minimize afterflow, a tool has been developed to shut a well in at formation depth. This tool, known as the collar lock pressure gauge plug, was designed and constructed to be run in the tubing against the stabilized flow of the producing well by means of a wire line. In this manner production of the well is not interrupted until the desired time of shut-in at the bottom of the tubing string. Field experiments have verified the applicability of the tool with flow rates as great as 225 B/D.

Tools are lubricated into the tubing string and retrieved in the conventional manner using a 24-ft lubricator and the usual wire-line tools. Except for running and setting the tool against a stabilized flow, wire-line operations are similar to those used with other chokes and plugs. Pressure gauges may be attached directly to the plug by means of a shock absorber, and field tests have shown that gauges run in this manner are not subjected to excessive shock.

**EXPERIMENTAL PROGRAM**

The collar lock pressure gauge plug just described has been used in several wells to obtain bottom-hole shut-in build-up curves for comparison with data from conventional surface shut-in tests and from theoretical investigations. The wells chosen for this experimental work were equipped with production packers which were checked for packer leaks prior to each test. In addition, observation of casing pressure during the tests indicated that the packers were not leaking, and eliminated the possibility that annular fluids above the packer exerted any influence upon the pressure measurements. The presence of packers in these wells also enabled the bottom-hole shut-in to more closely approximate shut-in at the sand face.

To obtain a valid comparison between a surface shut-in test and a bottom-hole shut-in test in the same well, individual wells were stabilized for equal time intervals and at equal production rates prior to both tests. The same pressure elements and bombs were used for both tests in each well. In the surface shut-in tests tandem bombs were run where possible — one containing a six-hour clock to increase resolution in the early portion of the build-up and the other, a 72-hour clock, for recording pressures at later times. Bottom-hole shut-in pressure measurements also were obtained using two bombs; the bomb containing the 72-hour clock was run on a tubing hanger and set in the first collar above the tubing stop, while the bomb containing the six-hour

![Fig. 1 — Pressure Build-up Curves of Gulf Coast Well No. 1 (Depth: 8,300 ft.)](image-url)
Bottum-Huu; ::'IUI'-IN AND SURFACE WELL Perforated Core Analysis Net sand thickness Depth of producing formation Stabilized rate of So Original reservoir Time of stabilization Bottom-hole Compressibility Rs Producing tubing stop. Depth of production Cumulative Production Gas 16,214 Mcf 33,121 Water FIG. 2—BOTTOM-HOLE SHUT-IN AND SURFACE SHUT-IN PRESSURE BUILD-UP CURVES OF SOUTH TEXAS WELL No. 1 (BOTTOM-HOLE FLOWING PRESSURE: 1,523 psi).

AUGUST, 1959

TABLE 1

<table>
<thead>
<tr>
<th>South Texas Well</th>
<th>South Texas Well</th>
<th>West Texas Well</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>No. 1</td>
<td>No. 2</td>
</tr>
<tr>
<td>Depth of producing formation</td>
<td>4531 ft</td>
<td>4265 ft</td>
</tr>
<tr>
<td>Wall spacing</td>
<td>40 acres</td>
<td>40 acres</td>
</tr>
<tr>
<td>Net sand thickness</td>
<td>7 ft</td>
<td>9 ft</td>
</tr>
<tr>
<td>Perforated interval</td>
<td>4526-4536 ft</td>
<td>4260-4264 ft</td>
</tr>
<tr>
<td>Original reservoir pressure</td>
<td>2023 psia</td>
<td>1,869 psia</td>
</tr>
</tbody>
</table>

Average hydrocarbon porosity 17% 17% 12%
Average permeability to air 153 md 130 md 44 md
$B_p$ at avg. pressure during build-up 1.32 1.27 1.23
$B_p$ at avg. pressure during build-up 0.00151 0.00158 —
$R_b$ at avg. pressure during build-up 0.33 cc 0.32 cc 0.72 cc
during build-up 550 ft3/bbl 410 ft3/bbl 600 ft3/bbl
Compressibility of reservoir fluids 9.35 X 10-5 psi-1 7.7 X 10-6 psi-1 9.15 X 10-4 psi-1
Bottom-hole temperature 156°F 169°F 83°F
Producing GOR at stabilized rate 6,000 ft3/bbl 800 ft3/bbl 650 ft3/bbl
Stabilized rate of production 17.6 ft3/D 35 ft/D 74 ft/D
Time of stabilization 5 days 5 days 5 days
Depth of bottom-hole shut-in 4337 ft 4031 ft 2400 ft
Depth of production packer 4461 ft 4175 ft 2503 ft

Clock was attached to the plug. After setting the lower bomb on the hanger, the plug with the other bomb attached was run and set in the second collar above the tubing stop.

Pertinent data concerning the wells analyzed are presented in Table 1.

METHODS OF ANALYSIS

The methods of analysis used in this paper are well known and are those presented by Miller, Dyes and Hutchinson, and by Perrine. To establish, however, that these standard methods of analysis, based on shutting-in at the sand face, can be satisfactorily used even though damage and afterflow are present, electrical analog and digital computer approaches were used to create theoretical curves for detailed comparison with the field curves obtained from the bottom-hole shut-in tests.

ANALYSIS OF BUILD-UP FROM SOUTH TEXAS WELL No. 1

The results of both the bottom-hole shut-in and surface shut-in tests made on this well are shown graphically in Fig. 2. These curves show vividly the difference between a surface shut-in where afterflow and phase segregation are active and a bottom-hole shut-in where the producing formation has been isolated from the tubing column.

The surface shut-in curve shows that afterflow was predominant to 60 minutes and that humping occurred after approximately 1.5 hours. It is apparent that this curve is not amenable to analysis using standard methods. On the other hand, the curve obtained from the bottom-hole shut-in shows no hump and a minimum of afterflow. In order to compare this bottom-hole shut-in curve with a theoretical curve, the methods previously outlined were applied to obtain the pertinent reservoir parameters. Since the producing gas-oil ratio of this well was considerably above solution ratio, it was apparent that two-phase flow was occurring within the reservoir; consequently, the equations dealing with multiphase flow were utilized and gave the following values: $m = 9.3$ psi/cycle; $q_g = 168$ reservoir B/D; and $z_f = 420$ md/ft.

These calculated values along with porosity, sand thickness and estimates of the effective drainage radius and fluid compressibility were sufficient to characterize an ideal system, and enabled a theoretical build-up curve to be obtained from both the digital and analog approaches. A reasonable value for the drainage radius was considered to be 660 ft. Best results were obtained by computing the reservoir fluid compressibility under the assumption that no gas went into solution during the time of build-up and by weighting the oil and gas compressibilities according to an estimate of the fractional portion of the hydrocarbon pore volume occupied by each phase.

Fig. 3 shows the field bottom-hole shut-in curve along with theoretical curves based on the constants just listed. The curve obtained by the digital approach with the assumption that no afterflow or damage was present showed deviation during the early portion of the build-up but essentially agreed throughout the remainder of the curve, including the straight-line portion. By introduction of damage and afterflow, the curve was essentially duplicated throughout. That damage was present in this well was confirmed by calculating the productivity ratio as defined by Perrine which gave a value of 0.20. The amount of afterflow which was introduced totaled 0.60 bbl of reservoir fluid and appeared reasonable to account for compression of the fluids which were present beneath the production packer in the casing and beneath the pressure gauge plug in the tubing during the bottom-hole shut-in test.

The excellent agreement between theoretical curves and the bottom-hole shut-in curve confirmed the belief that data from bottom-hole shut-in tests would yield reliable reservoir information using standard methods of analysis, even though surface shut-in data influenced by afterflow and phase segregation appeared anomal-
ous and impossible to analyze. Lending validity to this conclusion was the fact that the stabilized pressure computed by the Miller, Dyes and Hutchinson method was 1,827 psi, which was in excellent agreement with the stabilized pressure of the theoretical systems and the final pressure obtained from the bottom-hole shut-in test.

Analysis of Build-up from West Texas Well No. 1

The West Texas well analyzed in this study is producing from a recently discovered reservoir, the limits of which have not been defined. Although there are other wells in this reservoir, they were shut-in and did not limit the effective drainage radius of the well during the periods of stabilization and build-up.

Results of surface and bottom-hole shut-in tests made on this well are shown in Fig. 4. Once again the effects of afterflow and phase segregation are apparent in the surface shut-in build-up curve. The effects of phase redistribution in this test were not sufficient to produce an obvious hump, but instead appeared only as a distortion in the curve obscuring the straight-line portion needed for a conventional analysis.

The bubble point of this reservoir fluid is 1,060 psi at the reservoir temperature of 83°F and is undersaturated by 200 psi with respect to the average reservoir pressure. Consequently, very little free gas was flowing during stabilization of this well, and the equations for single-phase flow were used in analyzing the bottom-hole shut-in curve. The results of this analysis are:

\[ m = 19.5 \text{ psi/cycle}; \quad K_o = 19.5 \text{ md}; \quad \text{and productivity ratio} \quad \frac{\dot{q}_e}{K_o} = 0.35. \]

Fig. 5 shows the bottom-hole shut-in curve compared with theoretical curves obtained from the digital and analog approaches using the parameters listed previously. It was found that a drainage radius of at least 3,000 ft was necessary in order to duplicate the full 72-hour curve obtained in the field. When damage and afterflow were introduced in the analog, excellent agreement between the theoretical and bottom-hole shut-in curves was obtained.

Conclusions

Phase redistribution definitely affects most surface shut-in build-up curves. In many cases this effect, along with afterflow and damage, produce misleading results.

By means of the bottom-hole shut-in techniques described in this paper, phase redistribution is virtually eliminated and afterflow is minimized.

Build-up curves obtained by this technique present the character predicted by theory, and conventional methods of analysis applied to these curves yield reliable reservoir information.

Nomencalature*

- \( m \) = slope of straight-line portion of build-up curve
- \( q_e \) = equivalent production rate (reservoir barrels per day)
- \( \lambda_o \) = total oil and gas mobility (millidarcies/centipoise)
- \( \mu_o \) = oil viscosity (centipoise)

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References


* See AIME Symbols List in Trans. AIME (1956) 207, 588, for other symbol definitions.

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