Application of Reservoir Engineering to Field Operation

By

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INTRODUCTION

During recent years, the major technical advancement in the technology of petroleum production has been the application of producing practices that promote maximum recovery of hydrocarbon and efficient use of available reservoir energy commensurate with sound economics. Development of these practices has resulted from extensive laboratory research and critical analysis, observation, and application of field production practices.

Determination of the most efficient method of operation requires a detailed study of the many factors influencing behavior of the individual reservoirs. These determinations frequently involve an evaluation of the effects of such controllable factors as rate of production, well completion practices, gas-oil ratio behavior, and water production on the overall performance of a given reservoir. To meet these requirements, methods involving application of fundamental principles of fluid behavior to the complex geological structures that yield oil and gas have been developed. These methods permit an evaluation of past reservoir behavior and a prediction of the effects of variable future operations on the performance of the reservoir. As a result, it is possible to assign a monetary value to efficient practices for many reservoirs. However, it should be realized that the application of quantitative results of a reservoir analysis to control future behavior of a reservoir is possible only to a degree commensurate with the completeness and reliability of the information available concerning the producing reservoir, such as fluid content, pressure behavior, and past production of oil, gas, and water. Therefore, close cooperation is necessary among operating personnel, geologists, and engineers in the collection of accurate production and reservoir data in order to insure that the most reliable interpretation of reservoir performance is achieved.

It should be emphasized that the gathering of extensive, reliable data is the most important function performed in order that a reservoir analysis can be made that will result in increased recovery of oil and gas and/or lower operating costs.

Data Required for Reservoir Analysis

Although gathering of geological data is not a function performed by field, operating personnel, a basic understanding of certain reservoir rock and fluid properties such as porosity (the per cent of available pore space available for fluid storage), permeability (the relative ease by which fluids move through the porous rock) and saturation (a percentile of fractional amounts of various fluids and/or gas distributed throughout the reservoir's pore space) is needed.

Reservoir Pressures and Temperatures

Subsurface pressure measurements yield valuable information regarding the content and nature of an oil or gas reservoir and of an individual well within a reservoir.

While the subsurface pressure gauge yields the most reliable and accurate information, surface pressures often give useful data and should be taken with all possible care to be assured of representative information.

The purpose in making subsurface pressure measurements is to obtain information concerning variations in pressure with reservoir voidage. It is important that pressure measurements be maintained on a consistent basis so that pressure variations observed between surveys or between the initial pressure measurement and subsequent surveys will reflect true changes in reservoir pressure and not variations in survey technique.

Of major importance in obtaining accurate pressures is shut-in time. The shut-in period should be determined from pressure buildup measurements and each succeeding pressure survey should be run with the same shut-in period as the initial survey.

Oil demand has created a state-of-flux in producing operations. Switching from short calendar-day production to capacity production has made it very difficult to obtain test data. Most operators feel they can't afford to shut down for test purposes.

Characteristics of Reservoir Fluids

Obtaining reservoir fluid data is not normally a responsibility of field personnel other than the preparation of wells for suitable tests. It is of great importance for these people to follow suitable procedures for cleaning the well, observing length of shut-in time, etc., since saturation pressure, quantity of dissolved gas, viscosity, density, gas gravity and formation volume factors are derived from such well test information.[1]

Production History

Probably the most important information to the reservoir analyst are those data which pertain to the past performance of individual wells:

1. oil production
2. gas production (gas-oil ratio tests)
3. water production
4. any fluid losses such as casing leaks, blowouts, major flowline leaks, and any other possibilities for loss of fluid which would not be accounted for in routine production data
5. accurate measurement in commingled batteries
6. mechanical failures in dually completed wells
7. gas flared at heaters or tank batteries
8. accurate records of gas used on lease
9. metering inaccuracies:
   a. meter maintenance
   b. failure to report office plate changes

Utility of Data

Well test data and production histories provide information useful in:

1. predicting past behavior of a reservoir, especially in determining:
   a. changes in oil zone volume
   b. variations in gas-cap volume
   c. degree of water influx
   d. presence or absence of volumetric reservoir control
2. predicting future reservoir behavior under various rates and ratios of oil, gas and water production
3. determining the efficiency of oil displacement and ultimate oil recovery under various types of operations.

Operational Data and Its Effect on Calculations

Oil production figures SHOULD BE ACCURATELY REPORTED and constitute the best data source available. In gas production, metering equipment requires special maintenance and specific procedures must be followed in well testing. Although difficult to measure, water production data is very important in reservoir analysis and should be carefully measured. By all means, presence of water in a production stream should be noted and its source indicated, if known.

Summary

Although much of the data used by the reservoir engineer must be obtained through laboratory analysis techniques, operating personnel play a major role in making certain the well from which the data is obtained is properly prepared and equipped for sampling.

The controlling factor in any reservoir evaluation is production data. Accurate records of reservoir withdrawals are <u>the</u> essential factors of any reservoir analysis.

GAS RESERVOIRS

The need for gas reservoir and well data other than for purposes of paying taxes and royalties can be classified three ways: (1) determining productivity of the well, (2) calculating of reserves, and (3) ascertaining treatment requirements necessary to render the gas marketable.

Productivity

Knowledge of gas well productivity is needed for determining future gas deliverability and optimizing field development, especially in locating and sizing of gathering systems and separators for any liquid-handling requirements. In addition, gas well productivity is often used by state regulatory bodies to determine gas well allowables.

The productivity of a gas well is usually determined by one or a combination of back-pressure testing and isochronal testing. In either procedure, every attempt should be made to obtain data after achieving stabilized pressures and flow rates for the well. These tests are sometimes incorporated with draw-down or buildup pressure tests.

Back-pressure tests (normally used to obtain initial potential) usually take the form of a four-point test. The well is closed-in for at least 24 hours; then static-bottomhole and closed-in wellhead pressures are measured. The well is then opened to flow at four different rates; and the volume of gas produced at each rate, bottom-hole pressure and wellhead pressure are determined.[2,3] An example four-point plot is shown in Fig. 1, indicating that the well was reasonably prepared for testing and that the data obtained are usable since all four points fall along a straight line.

Figure 2 shows an example four-point plot exhibiting scattering. A straight line cannot be drawn through these points. The well was not stabilized prior to testing.

If the well is properly conditioned before test, a reasonable estimate of productivity is usually possible. However, it is usually found that when a gas well is put on stream and produced for several months a retest of the well will reveal a shift of the four-point line to the left as shown on Fig. 3. On occasion, such testing will show a shift to the right, indicating an improvement in productivity.

The isochronal test consists of a series of pressure-buildup tests (to measure permeability and pressure) sandwiched between four-point type drawdown flow tests. Although this test provides valuable reservoir information, it is us-

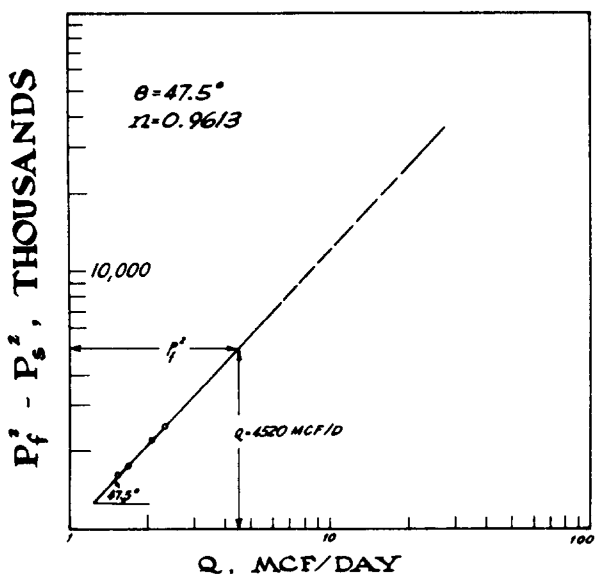

FIGURE 1

Good example of back-pressure gas well test (field example).

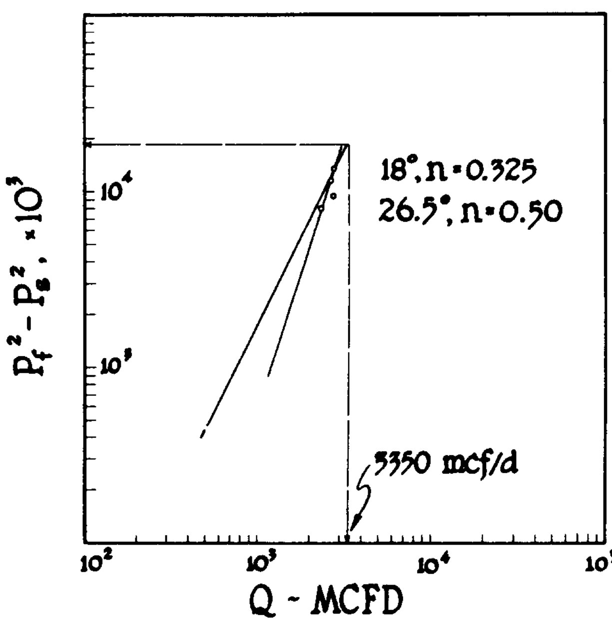

FIGURE 2

Example of back-pressure testing of an unstabilized gas well.

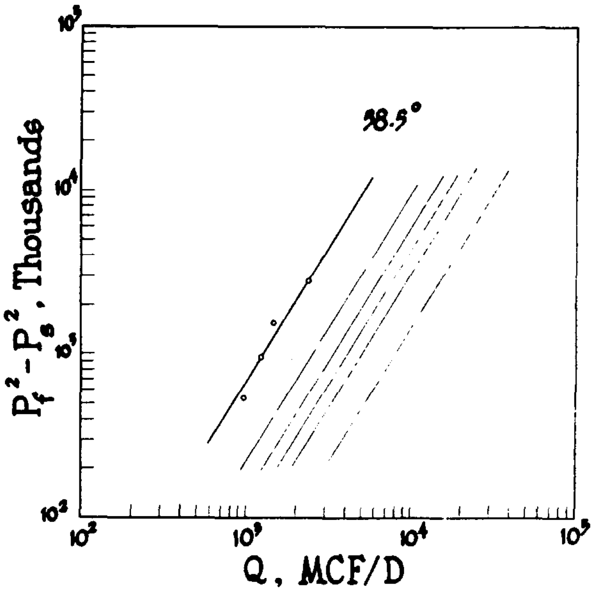

FIGURE 3

Shifting of back-pressure curve after sustained production of a gas well (field example).

ually impractical to use unless the well is on stream because of the time and volume of flare gas required.

Surface and subsurface measurements are usually made subsequent to initial potential tests. Surface measurements usually involve obtaining a 24-hour stabilized flow test and corresponding flowing tubing and casing pressures. This is followed by shutting the well in to obtain a maximum shut-in wellhead pressure. These tests should be made with either dead weight testers or by hooking up an Amerada-or Humble-type bottom-hole pressure bomb to the wellhead. These data can be plotted against original back-pressure test data to obtain current absolute open flow for the well.

Because of the expense and shutdown time required it is often not feasible to obtain subsurface pressure data. In such cases, extra care should be taken to note all well conditions in order that the best extrapolation of bottom-hole pressure can be made. Such calculations are influenced by gas gravity, liquids in the stream, collection of fluids in the tubing, temperatures, etc.

Reserves

Gas reserves are usually estimated by either volumetric or pressure extrapolation techniques. Volumetric calculations are used for new wells in a developing field unless the reservoir is so small that initial performance has caused a drop in average reservoir pressure. In this event, reserves estimate by pressure extrapolation is appropriate.

In the use of pressure extrapolation techniques (P/Z vs cumulative gas production) it is usually considered necessary to have produced from 5 to 10 per cent of the gas-in-place to provide data for a reliable reserve estimate. This rule-of-thumb varies with the type of reservoir; the more permeable reservoir will allow earlier estimates to be made.

In estimating reserves, reservoirs may be classified in three ways: (1) reservoirs with complete communication, (2) reservoirs with limited communication, and (3) reservoirs where water influx results in limited or no pressure drop. Reservoirs in the first two categories are characteristically of a volumetric nature.

In a reservoir with complete communication and high permeability, it is possible to deplete the reservoir with one well situated reasonably in the center of the field. Figure 4 shows pressure decline versus cumulative gas production for a Clearfork reservoir in Crane County, Texas. Most of these pressure values were obtained at the sand face. This reservoir had reasonably good

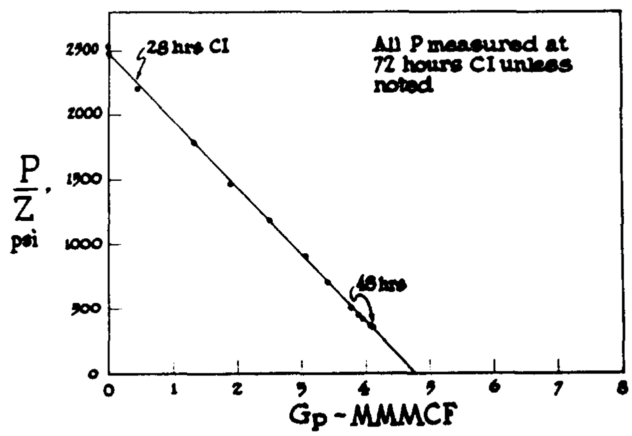

FIGURE 4

Pressure-production performance for a volumetric gas reservoir. (Clearfork formation, Crane County, Texas).

permeability, as indicated by its CAOF of 31000 MCF/D; in this particular reservoir there was reasonable agreement between the volumetric and pressure-curve methods.

As permeability decreases in a reservoir, the data normally becomes less accurate unless the well is shut in for an extended period of time to obtain static bottom-hole pressure. However, a reasonable extrapolation of the bottom-hole pressure decline curve can be made if pressure measurements during the life of the field are obtained from wells that are consistently shut in the same length of time. Figure 5 illustrates such performance for a one-well, low-permeability reservoir. Note that an extrapolation of pressure decline early in the life of the field would have resulted in a significant error in reserves estimate. However, after the well had produced for some time and achieved an approximate stabilized flow, a trend developed which when extrapolated gave only a slightly pessimistic estimate of gas-in-place. Thus, if early in the life of the reservoir a few maximum bottom-hole pressure buildups are obtained, a later decline trend can be paralleled through these maximum buildups to obtain a fairly reasonable estimate of gas-in-place.

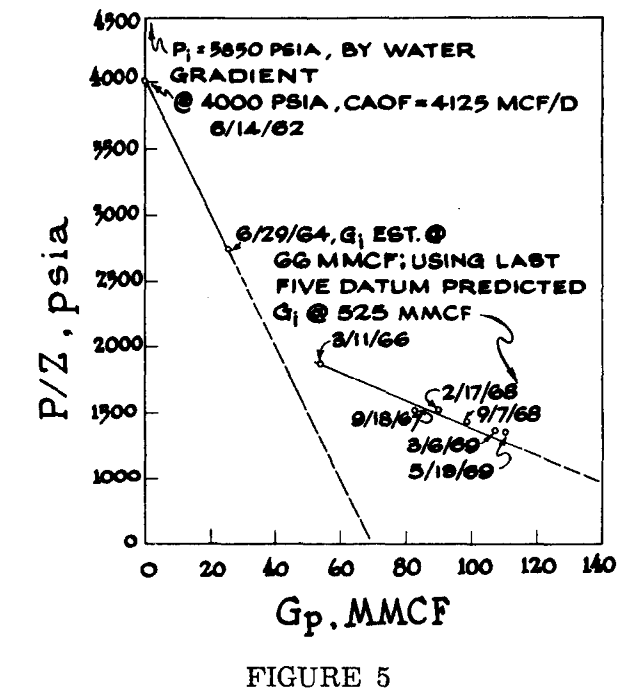

FIGURE 5

Performance curve for a one-well, low-permeability reservoir, illustrating invalid early pressure data (Ellenberger formation).

Usually, in most gas reservoirs, higher producing rates are desired to meet pipeline obligations, requiring multiple wells. And, in more permeable reservoirs where one well will not drain the entire field, or where multiple stringers are present, additional wells are necessary to maximize recovery. Figure 6 shows pressure performance of a three-well field producing gas from a sand in Crane County, Texas. Initially, two wells were drilled, but subsequent additional deliverability requirements necessitated a third well. In studying core analysis and well completion information it is not certain that the higher pressure at completion of well No. 3 is attributable to pressure transients in the original reservoir or if an additional sand member was penetrated. Later performance of the well suggests that the latter is the case, that an additional stringer was present. Reservoir pressure equalized rapidly with the other wells and then all three wells continued to decline at the same rate.

An example of multi-well gas field operations is the Puckett Ellenburger Field, Pecos County, Texas. Figure 7 shows the pressure history for this reservoir. The size of the reservoir, and competitive operations, dictated multi-well completion. Two pressure curves are shown for this reservoir to point out the difference that the z-factor can make in reserve estimation. In

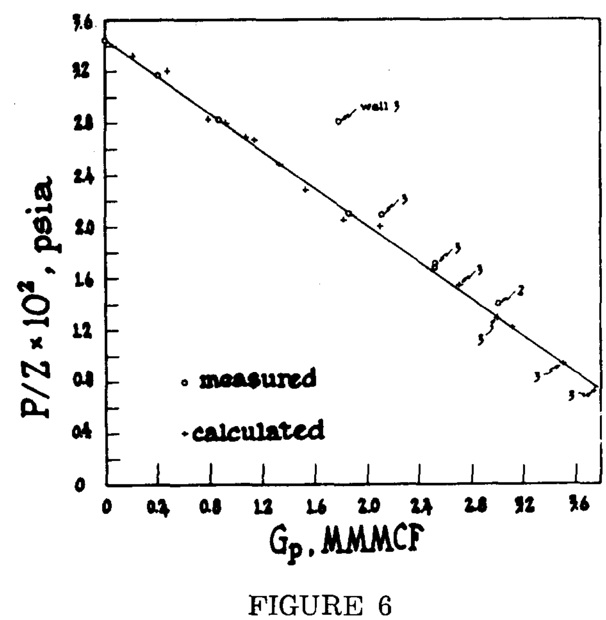

FIGURE 6

Multi-well gas reservoir. Completion of third well indicates higher pressure-transient due to gas from an additional pay section.

the upper curve a calculated z-factor was utilized; a distinct break in the curve is noted. Linear extrapolation of the first several points would have resulted in about a 20 per cent overestimation of gas-in-place. The lower curve was based on z-factors determined by laboratory measurement (laboratory determinations were needed because very little z-factor data is available above 5000 psia, especially for gas containing large percentages of contaminants). In the case of the Puckett Ellenburger, its produced gas contains about 28 mol per cent CO_2.

Another interesting feature of this reservoir is that maximum wellhead pressures are usually obtained within an hour after shut-in, declining thereafter. Since bottom-hole pressure is an important factor in determining well allowables, all operators have tested their wells thoroughly to determine minimum shut-in time to maximize wellhead pressure. Wellhead pressures are relied on since the corrosive nature of the gas at such depths makes bottom-hole pressure runs risky. In addition, completion pressures, as shown in Fig. 7, indicate that the field has excellent communication; older wells have drained gas from areas of the field developed at a later date.

Finally, it is extremely important to know as early as possible if a gas reservoir is under water-drive since recovery from a water-drive reservoir is less than one under pressure-depletion. Figure 8 shows data for a Siluro-Devonian field, Reeves County, Texas, under water-drive. Practically no pressure drop has occurred throughout the history of the reservoir, and at present most of its wells are watered-out. In such fields only volumetric reserve estimates are of any value since the water-drive sustains pressure. This particular reservoir causes even more difficulty because it has a partial water-drive.

Sometimes, in such reservoirs, pressures will

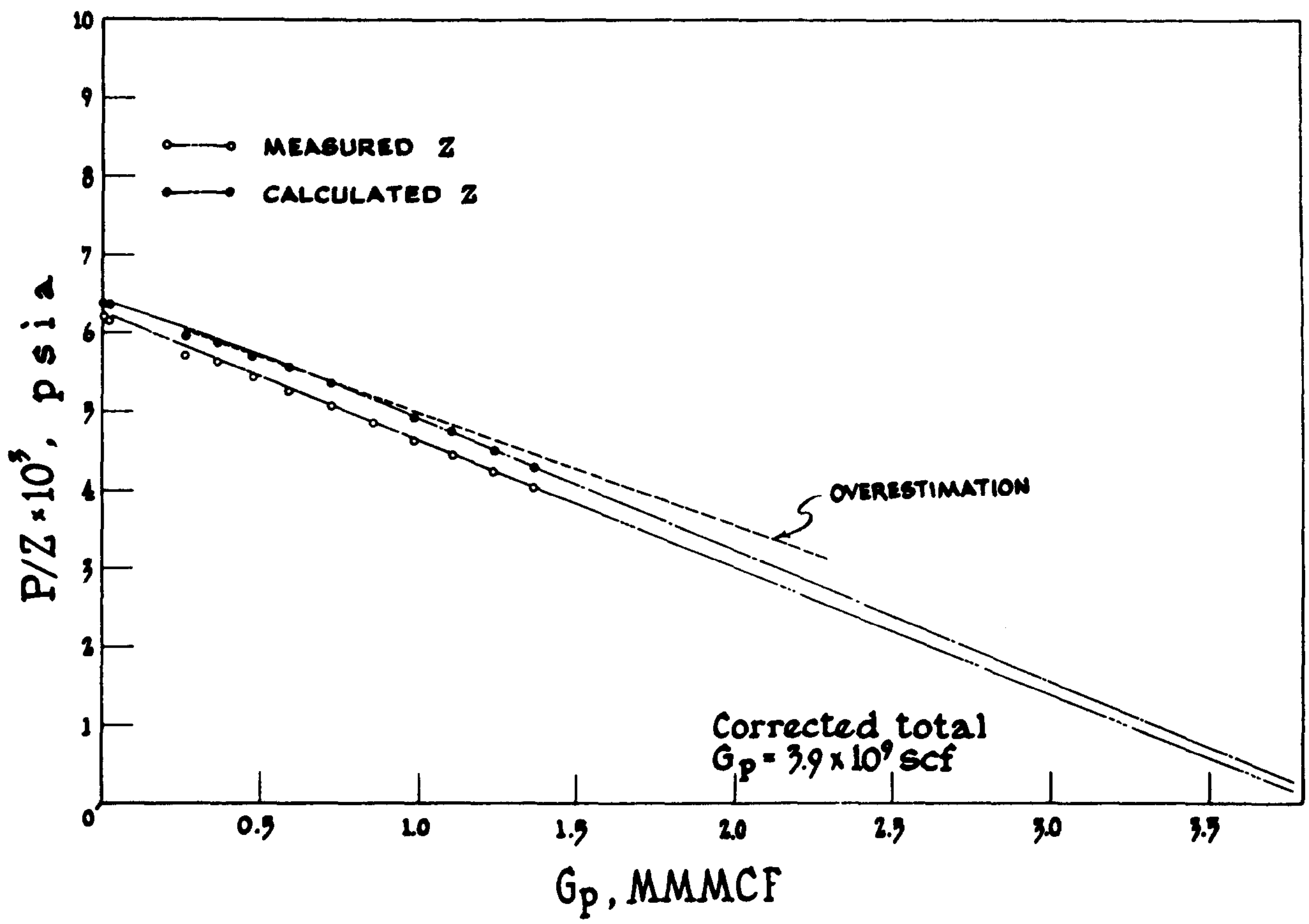

FIGURE 7

Puckett-Ellenberger reservoir illustrating effect of erroneous z-factor data for reserve estimation.

decline "normally" for a time then flatten out, and in cases where the aquifer supplying the water is small, the wells may water-out prior to a "flattening" of the decline curve. An example of this type of performance is shown in Fig. 9 as the Heiner South Willberns Dolomite field, Pecos County, Texas. The pressure history describes a normal pressure-depletion mechanism. However, the wells watered-out at about 50 per cent that of expected pressure depletion.

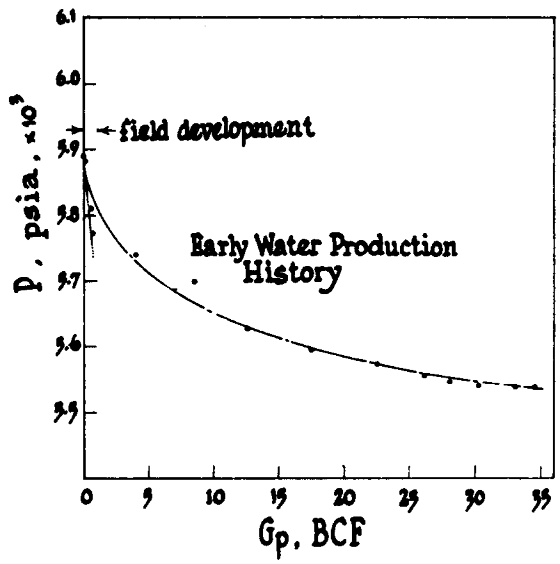

FIGURE 8

Gas reservoir performance for a multi-well reservoir under water-drive (Siluro-Devonian formation, Reeves County, Texas). Data reconstructed from pressure-buildup surveys and cumulative production figures.

Thus, it is extremely important that any indications of water production be reported immediately in gas reservoir operations.

Treatments

It is very important, near well completion time, in a new field that the physical properties and composition of the gas be determined so that treating facilities may be designed. This is in addition to the value such data contributes to reservoir engineering calculations.

Normally, GPM test data obtained from laboratory or field tests help determine the need for and type of liquids-handling facilities required on the lease, and aid in optimizing facilities at the gasoline plant for maximum hydrocarbon liquid extraction.

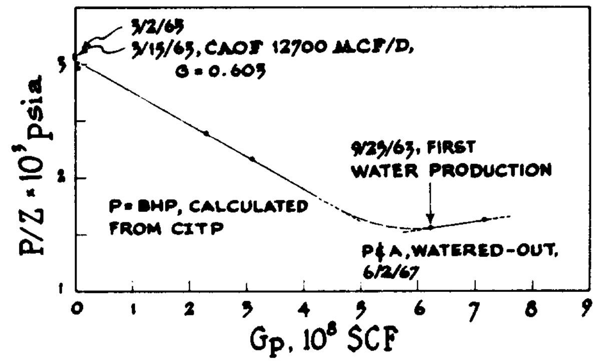

FIGURE 9

Pressure z vs production history for the Heiner-South Ellenberger, illustrating effect of water encroachment late in field life.

Gas composition data are used to determine the corrosive nature of the gas and are used in the determining of compresssibility data so necessary in forecasting reservoir performance and in estimating gas reserves.

Other tests performed include ASTM distillation tests, BTU content tests and recombined surface sample tests (important in condensate or distillate reservoirs). State regulatory bodies normally have certain requirements to determine if the very rich condensate fluids are actually in the gaseous state in the reservoir. These tests are also important for determining if recycling lease facilities are needed to maximize liquid recovery.

It is extremely important that samples are correctly taken from a properly conditioned well.

OIL RESERVOIRS—PRIMARY PERFORMANCE

Introduction

Primary performance of an oil reservoir is predicated upon size, depth, saturation distribution, reservoir pressure and flow properties of the reservoir. Performance is usually measured as a function of unit rate of recovery of producible reserves correlated with time. Such monitoring requires valid data usable in computing oil-in-place, producible reserves, optimized flow rates and type of reservoir drive or drives causing oil expulsion. Any and all field conditions relating to the above affect the economic attractiveness of the oil property.

Reserves Estimation

Early pressure-production behavior may indicate the dominant producing mechanism of the reservoir. Core data may yield barrels of stock tank oil per acre-foot or, with additional well completion data, yield oil-in-place values. More sophisticated treatment of field data, coupled with laboratory studies of reservoir rock and fluids, provide input for material-balance calculations. With sufficient performance data, such calculations may be checked against decline curve predictions (rate performance declines logarithmically with time).

Data Gathering

Obviously, the additional investment of acquiring valid field data and samples pays off in better reservoir analysis.

Appropriate well logs yield important parameters such as net pay, porosity, fluid saturation, reservoir temperature and lithology. Good cores will yield valuable reservoir rock properties which may be correlated with log information. Pressure testing (PBU, DST, PDD) is of immense importance in proper reservoir control. Poor data are probably worse than no data.

Field information, of seemingly little importance, may be just the clue to indicate a major change in overall reservoir behavior. For example, the sudden appearance of traces of water in production may indicate the start of a water-drive mechanism.

Productivity Index

Productivity index is the ratio of oil production to pressure drawdown and as such provides a suitable indicator of well performance. A constant-valued PI indicates the reservoir portion drained by the well is under semi-steady state flow. Excessive flow rate reduces PI, and pressure differentials measured may not reflect the total pressure drop from the well to its steady-state drainage radius as shown in Fig. 10. PI calculations, in conjunction with pressure-buildup tests should indicate if the well suffers damage, limiting productivity. It is then valuable to obtain reliable initial PI's as early as possible.

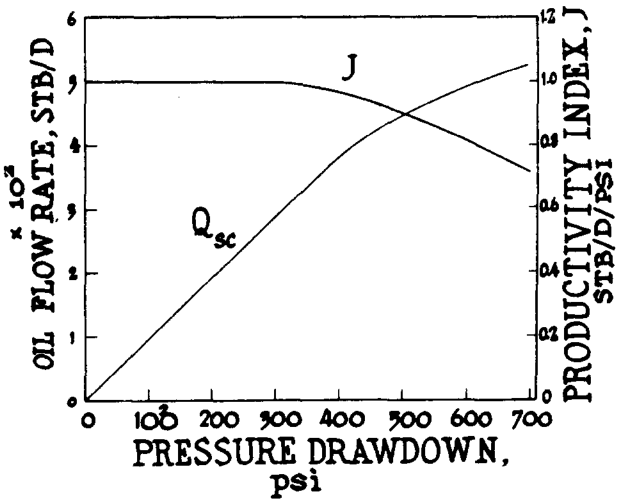

FIGURE 10

Decline in productivity at higher flowrates (after Craft and Hawkins, "Applied Petroleum Reservoir Engineering", Prentice-Hall, p. 290, 1959.

Formation Volume Factor

The ratio of unit reservoir oil volume to unit surface oil volume (shrinkage), B_o, provides valuable information relating to reservoir performance. Consider the behavior of B_o versus pressure, as shown in Fig. 11. As reservoir pressure drops from initial to bubble-point conditions, reservoir oil expands, linearly, due to fluid expansion at constant gas-oil rates occurring prior to free gas forming in the reservoir. From bubble-point pressure, P_b, to abandonment, gas con-

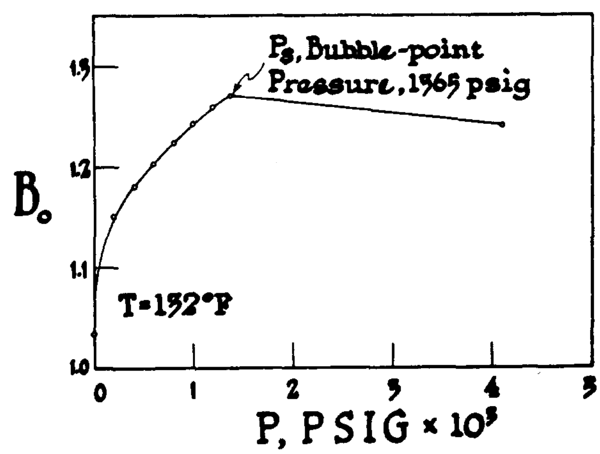

FIGURE 11

Measured crude shrinkage during differential liberation, 132°F. B vs P, Wolfcamp Reservoir.

tinues to break out of solution with a continuous decrease in unit reservoir oil volume. Consequently, knowledge of B_o and reservoir pressure indicates the stage and type of depletion taking place in the reservoir.

B_o is usually measured in the laboratory from suitable reservoir fluid samples. B_o can also be estimated from fluid gradients measured in the wellbore.[2]

Reservoir Mechanisms

Petroleum is produced, as primary production, by one or a combination of reservoir drives Examples are shown in Table 1.

TABLE 1

Reservoir Mechanisms and Example Reservoirs

Drive	Example Reservoir
Solution-gas drive	Slaughter San Andres
Bottom-water drive	Wellman Wolfcamp
Edge-water drive	North Russell Devonian
Gas-cap drive	Seminole San Andres

Solution-gas reservoirs produce hydrocarbons by expansion of dissolved gas, and may be assisted by expansion of a secondary gas cap. Either or both drives may be associated with water-drive. When reservoir permeability is high, oil viscosity is low (especially in either steeply dipping reservoirs or in reservoirs possessing high vertical permeability; gravity drainage may occur.

Production Behavior

When a reservoir produces below its bubble-point, vacated pore volume is filled with liberated (free) gas. Thus, the amount of gas space occupied is a key to estimating ultimate recovery, especially in solution-gas reservoirs, where the free gas saturation impedes oil flow to the producing well.

Higher solution GOR's or lower oil viscosities tend to increase final gas saturation, and conversely. High GOR's are indicative of the competition for pore space between oil droplets and gas bubbles. Producing GOR's are then often used as an indication of oil-producing efficiency. An increase in GOR is a "danger signal" in the behavior of a reservoir. Maintaining low GOR's also reduces lifting costs and conserves pressure. However, this control must be inaugurated early in the life of the reservoir.

As wells are produced, pressure changes occur which cause changes in equilibrium conditions between liquid and vapor phases, resulting in fluid redistribution and changes in the state of hydrocarbon content of the reservoir. Initial reservoir pressure and temperature are very important in monitoring these changes. Consequently, accurate measurements should be made. If subsurface measurements cannot be made, careful surface measurements, properly extrapolated, should be made.

In stratified reservoirs the depletion process is more rapid in the higher permeability layers This requires monitoring of each contiguous layer, especially if water-drive is present.

Additional recovery can be realized when a high-pressure, under-saturated reservoir is allowed to produce by oil and water expansion and rock compressibility until bubble-point is reached. In the case of the Ventura Avenue field (California) the D-7 zone produced 40 per cent of its oil-in-place by this mechanism.[3]

Gravity drainage requires conditions of low viscosity, high porosity, high vertical permeability or steep dip. Ultimate recoveries are usually high. An outstanding example of such a reservoir is the Porinas sandstone of the Mile Six pool in Peru in which gravity drainage was coupled with gas-cap expansion.[4]

Water-drive reservoirs usually have good recovery efficiencies unless stratification encourages early or erratic water breakthrough into the producing wells. Knowing whether a reservoir is under water-drive (e.g., is the drive edge-water or bottom-water) is important to the operation of wells, especially in determining abandonment or workover requirements. For example, water production deduced to be bottom water, may only require that downhole equipment be raised, the well plugged-back and/or producing rate be reduced to prevent coning. On the other hand, edge-water production would usually indicate earlier abandonment of the well.

Where water serves as a displacing agent, residual oil saturation may be used as an index of recovery much as residual gas saturation is used in depletion-type reservoirs. To determine such recovery, interstitial water and oil with initial dissolved gas are compared to interstitial water and residual oil saturation remaining at abandonment, with differential oil saturation as a measure of recoverable oil.

Some limestone reefs, producing under a bottom water-drive, have extreme ranges in permeability and the effect of bouyancy through the vugs can aid in recovering oil from the matrix porosity by imbibition.[5]

Performance Curves

After production data for a reservoir is available, estimates of ultimate recovery can be made by extrapolating performance curves (decline curves) under the basic assumption that whatever governed the previous trend will continue to govern that trend in a uniform (predictable) manner.

Therefore, producing rate is plotted versus time or cumulative production to establish a decline curve that is then extrapolated to an economic limit. Proration defers the use of decline curves until the wells become capacity or marginal producers.

Figure 12 shows decline curve performance for the Calvin field in Illinois by plotting per cent of oil in total fluid produced (oil-cut) versus cumulative oil production.[6] In this example, ultimate recovery is predicted at the point where only two per cent of the produced stream is oil (98 per cent water-cut). Figure 13 shows decline curve treatment for the Woodbine East Texas field by plotting the oil-water contact versus cumulative production.[6] Abandonment is predicted on watering-out the oil column to the average top of the Woodbine sand.

A more typical decline curve is shown as Fig. 14 where oil rate is plotted logarithmically versus cumulative recovery. Abandonment conditions are predicted by extrapolating the straight line trend shown on the graph.

An important use of reservoir estimates is the comparison between volumetric recovery and recovery obtained by projecting individual well performance, although it is sometimes difficult to fit the projected well performance to the volumetric estimate. If a substantially lower recovery is indicated from such performance, the production practice may be wrong, more wells may be needed, or stimulation treatments are in order. If well performance projections indicate an ultimate recovery in excess of volumetric estimates, the converse is true. In the latter case, subsurface interpretation may be in error and a larger oil reservoir than suspected may exist.

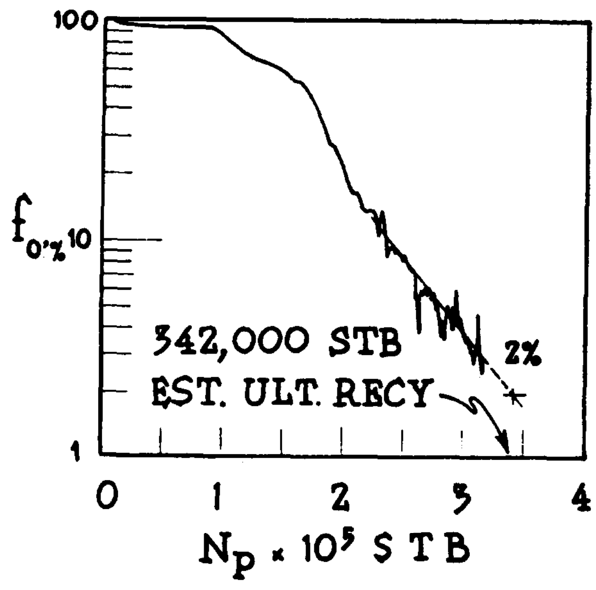

FIGURE 12

Oil percentage versus cumulative oil, Tar Springs Sand, Calvin Field, Illinois (Adapted after SPE Reprint No. 3: Oil and Gas Property Evaluation and Reserve Estimates, p. 23).

Relative Permeability Ratio

The most important single factor governing recovery efficiency of a reservoir is the ratio of gas flow to oil flow, measured by relative per-

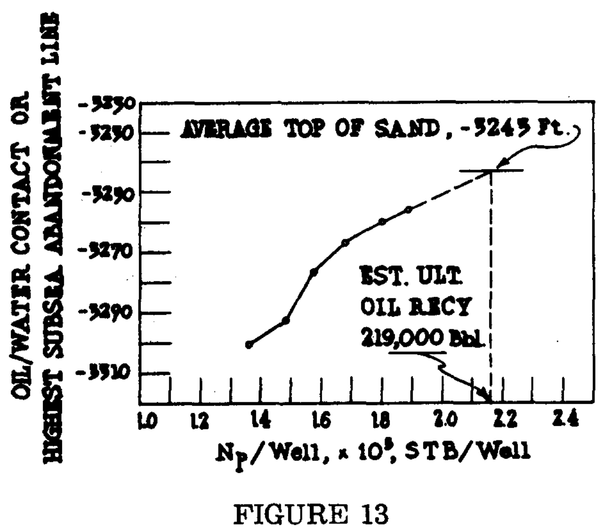

FIGURE 13

Subsea abandonment line versus oil recovery. Woodbine Sand-East Texas field (after Katz, Trans. AIME, 1942, p. 146, 28).

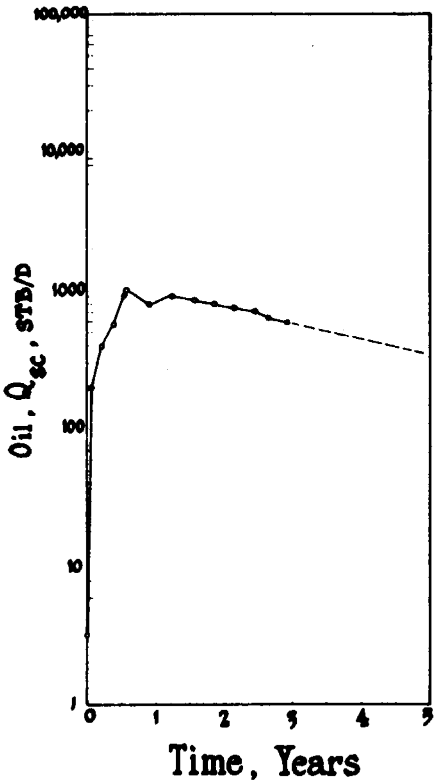

FIGURE 14

Typical decline curve, oil-flow rate versus time (Permian Basin Example).

meability ratio, kg/ko. Figure 15 shows log of kg/ko plotted versus total liquid saturation for a West Texas reservoir. It is noted, for this example, that at high liquid saturations kg/ko approaches zero, but as liquid saturation reduces (gas saturation increases) a disproportionate increase in kg/ko occurs, greatly affecting liquid recovery. Near abandonment conditions, kg/ko is quite high and the reservoir literally "blows" itself down with mostly gas production. The importance of field data is reflected in the fact that kg/ko behavior can be monitored by field GOR tests. These results bear directly on knowing the true behavior of a given reservoir, especially in predicting depletion performance.

OIL RESERVOIRS—SECONDARY RECOVERY

Evaluation of Reservoir for Increased Recovery

During primary production of an oil reservoir it may become apparent, through evaluation techniques and/or field observations, that productivity can be improved by injection of extraneous material into the oil reservoir.

All the data accumulated to this time—laboratory, production and geological—can be utilized to determine the feasibility of increasing oil recovery over that to be expected through application of a secondary recovery process.

From laboratory data, reservoir rock and fluid properties may be determined, permitting calculation of the displacement efficiency of the reservoir in yielding oil by the secondary recovery process under study. Such reservoir analysis helps answer questions pertaining to the flow capacity of the reservoir-reservoir volume, storage, net thickness, removable oil volume and efficiency of the system (volumetrically and time-wise).

Production tests and geological data help determine the shape of the reservoir and the best well spacing for the problem, and usually indicate the presence of secondary-gas-cap formation and/or the activity of water-drive. Such studies may even prove that the recovery process is no more efficient than the natural reservoir

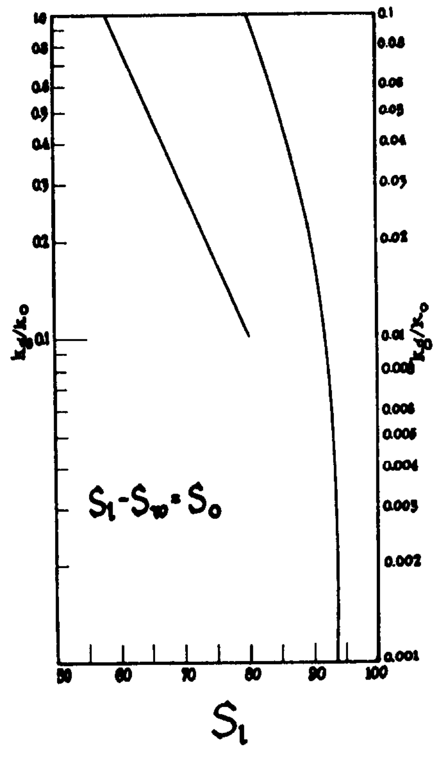

FIGURE 15

Relative-permeability ratio, gas-to-oil versus total liquid saturation, West Texas reservoir.

mechanism.

Preliminary studies may point to a more sophisticated analysis, such as numeric modeling of the reservoir. Simulation as well as engineering calculations can forecast performance of a new reservoir early in its life. Projections made as to its primary performance and secondary performance can be melded with economics to decide in advance how the field should be operated. The key to this comparison is incremental recovery per unit investment.

The end result of all such evaluation is to ascertain the profitability of a proposed fluid injection program. Sometimes action is justified in that anticipated expenditures may be deferred or deleted entirely. The cost to install the injection facility is compared with the value of increased recovery to determine the feasibility of the operation. This is illustrated in Table 2.

Surveillance of Fluid Injection

The responsibility of the operation of the increased recovery project rests with the field operating personnel with counselling from technical personnel assigned to the project. Continuous evaluation of instantaneous performance data is used to monitor the behavior of the flood. Chief data of this sort are gas-oil ratio, oil-flow rate, water-oil ratio (or water-cut) and bottom-hole pressure measurements at the injector and producing well. The efficacy of the flood can be followed by proper interpretation of these data. For example, an increase in water-cut may indicate premature water bank breakthrough. A decrease in oil rate may be traced to injection well plugging or perhaps skin damage to the producing well. Periodic well tests are needed to maintain effective records to incur maximum rate in minimum time and expense. Thus, well

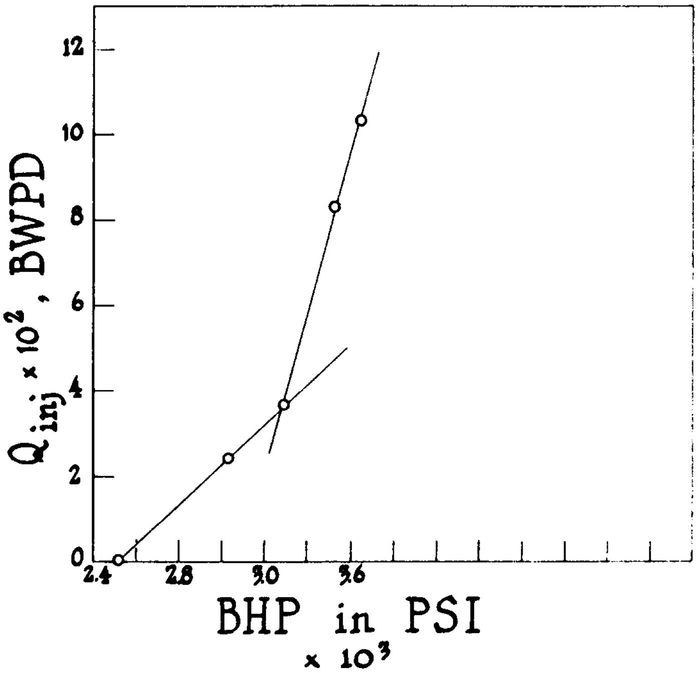

FIGURE 16

Two-rate step test for injection-well testing. Injection rate versus bottom-hole pressure:

Q,B/D	Surface Pressure, psi	BHP, psi
0	750	2520
240	1250	3036
365	1525	3290
487	1675	3470
830	1800	3530
1035	1850	3650

TABLE 2

Economic Analysis Of A Secondary Recovery Project*

Incremental Oil	Value of Oil	Direct Costs	Net Income	Additional Investment
1000	3000	750	2250	1500
800	2400	750	1650	500
700	2100	750	1350	0
500	1500	750	750	0
3000	9000	3000	6000	2000

Undiscounted net income = 6000–2000 = $4000

*All values X 1000

test data (such as oil rate, water rate, gas rate) are prime tools in determining the effectiveness of the increased recovery program.

An important feature of any injection well test is to determine if fluid is uniformly entering an oil-saturated portion of the reservoir. If severe formation parting occurs, substantial volumes of recoverable oil are bypassed. Pressure fall-off tests are used to determine the maximum injection rate that will not split the formation. In this test, pressure is plotted versus corresponding rate with an abrupt "break" in curve behavior indicating maximum rate and pressure. An example is shown in Fig. 16.

Typically, flood performance follows the trend shown in Fig. 7. If injection rate continually declines, remedial work on injection wells should be attempted to stabilize or increase injection rate. If this fails, then the producing end of the system should be examined. Figure 18 shows another way of detecting injection well trouble. The curve indicates a reduction in volume of injection material entering the system.

Sensitivity of Evaluation to Field Performance Data

Comparison of a reservoir study to actual project performance is the "acid" test of reservoir forecasting; but, the calculations and studies are greatly dependent upon reliable historical field data such as GOR's, WOR's, BHP's, oil, gas and water volumes with respect to time. If the accuracy of historical data is questionable, the value of current data is also subject to question. But, most operators, by necessity, accept the amount of oil sold as an accurate figure. This places the burden upon the reservoir analyst to prove that historical data is either wrong or input data of the study is in error. It can not, then, be overstated that correct production records are essential for oil property management.

VALUE OF DATA

Introduction

Before considering the value of data, examine the data which would normally be collected in the field:

1. Fluid production rates—oil or condensate and water
2. Gas production rates — orifice meter readings, side static pressure readings, choke nipple pressure, etc.
3. Pressures—surface and subsurface wellbore pressures and lease equipment pressures
4. Fluid properties—oil gravity and temperature, BS&W content of oil and water salinity
5. Gas properties—gravity, hydrogen sul-

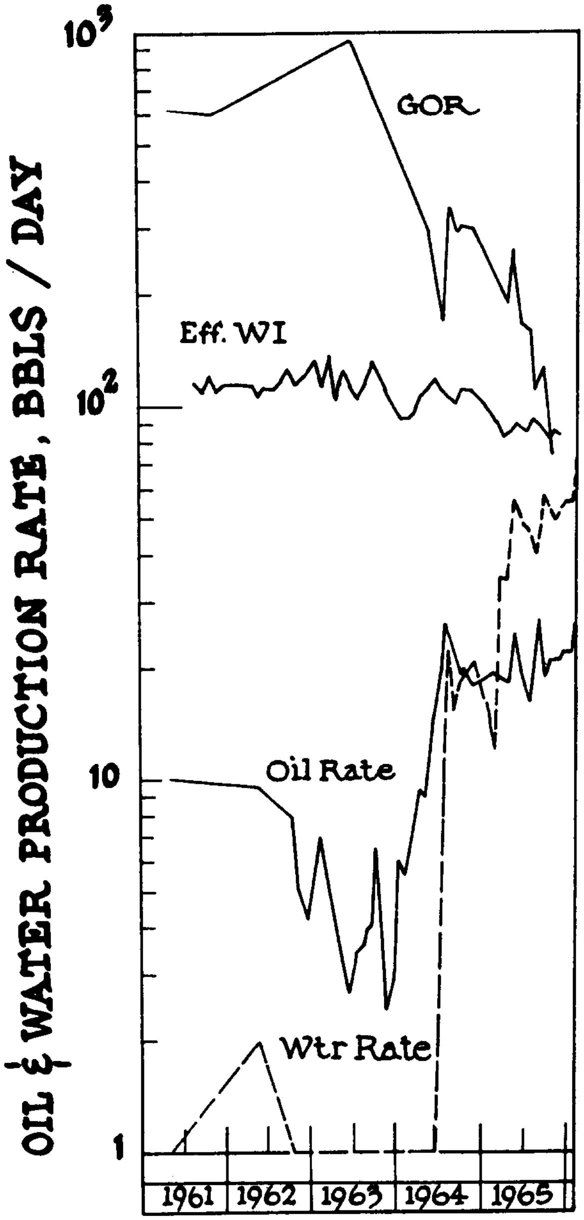

FIGURE 17

Typical waterflood performance.

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6. Temperature—subsurface wellbore, wellhead, and lease equipment.

Assuming for the moment that the data needed for a particular well or field have been collected and accurately recorded, how valuable is that information? Regardless of whether an oil or gas well has just been opened to production or whether it has been on production for months or years, several basic questions always come forward. First, how much oil and/or gas is contained in producing zones under this well tract? Second, how much of that oil and/or gas might be produced under natural depletion; that is, how much could be produced by flowing and/or pumping the well until a profit could no longer be made? Further, in the case of an oil reservoir, how much additional oil might be recovered by supplementing natural producing energy by injecting water, gas, or light hydrocarbons, such as propane. Third, how much oil, water and/or gas has this well produced and how much will it actually produce today under existing conditions, and could or should it produce at a higher oil and/or gas rate? Fourth, under existing conditions such as market demand, equipment installation and formation flow capacity, at what rate will the well produce in the future? And what might be done to optimize this predicted rate of production?

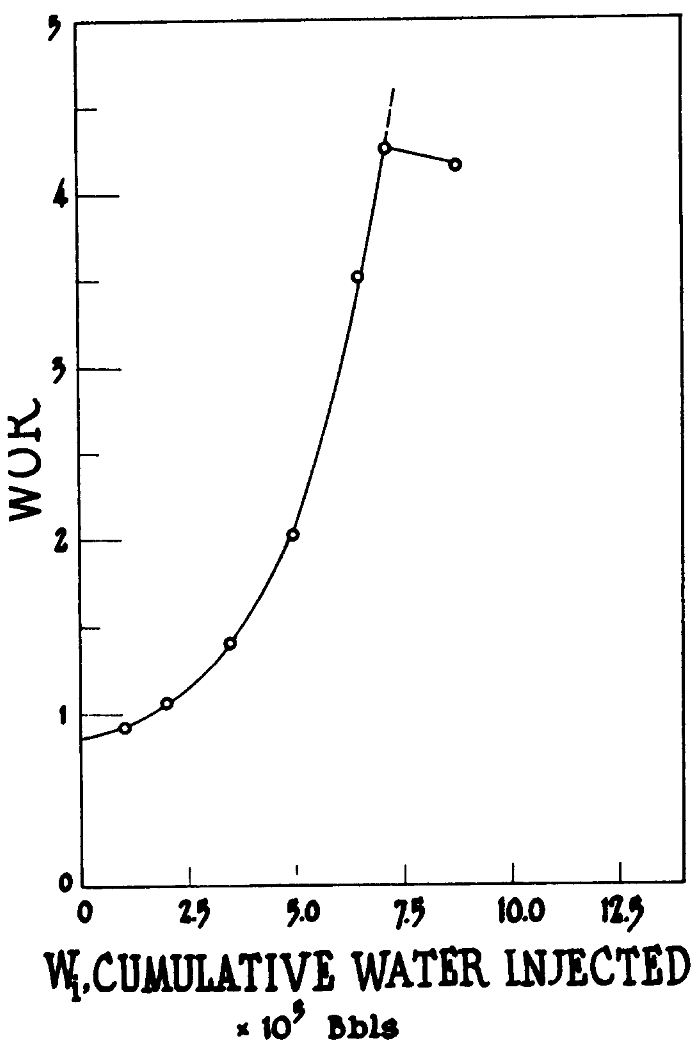

FIGURE 18

Water-oil ratio versus cumulative water injected, illustrating abnormal reduction of injection volume.

The individual or company who spends the money to drill, complete and produce a well, or anyone who is interested in purchasing that well, is not likely to consider these questions as being just academic or theoretical; however, many of the estimates made to answer these questions will necessarily come from theoretical calculations. As a general rule it can be said that the accuracy of these calculations will be no better than the accuracy of the data collected in the field.

In addition to answering an owner's questions as to hydrocarbon reserves, equipment selection, sales volumes, treatments, and future producing rates, data required by state and federal regulatory bodies are used in determining allowable producing rates.

So without repeating how the data collected in the field are actually used in calculations, it is safe to say that collecting and recording the proper data is the key to efficient operations and in many, many cases leads to higher allowables, higher sustained production rates, and increased ultimate recovery of oil and gas.

Initial Test Requirements

Consider that an initial production test is required on a well. This test would be used to decide on stimulation needs, value of a previous treatment, or equipment size. If the test were performed on a completed well, the information would provide appropriate well allowable. In the case of a one-well reservoir, each day's performance is a test.

Influence of Regulatory Requirements

In the United States, regulation of oil production is a state's right. The state agency, so designated, established rules, regulations and guidelines as to extraction of petroleum. Consequently, much well testing is conducted to satisfy state requirements. This is especially true with new wells where initial potentials are established or where later tests are compared with initial tests. For example in Texas, the initial potential of an oil well is followed by a 30-day GOR test and semiannual and annual tests on oil wells are also prescribed. Gas wells require initial potential tests (G-1), usually four-point pressure tests, and an annual (G-2) test.

Often the reservoir engineer finds such tests to be the only ones run for a given well. If the operator has not entered into the spirit of the matter (merely complying with state law by supplying dubious or careless information) valuable field data have been irrevocably lost. As an example, a back-pressure gas test run by the usual pressure drawdown rate-increase procedure invariably gives a lower gas potential than that derived by obtaining the data through a pressure-buildup, rate reduction procedure. Although initial potential is more favorable on a rate assignment basis, there is grave doubt that this rate is the true potential of the field.

Determination of Productivity

Initial testing determines the well's initial capacity to produce hydrocarbon. This may or may not reveal the ability of the well to continue to produce. Later testing is required to verify or clarify producing-rate trend and longevity. And, such tests help in determining equipment needed on the lease and in the prediction of future lease equipment requirements.

Testing provides data helpful in forecasting rates with time. This, in time, establishes potential income and future development possibilities. It also helps management to predict income and future expenses. The record of individual well productivity will help determine at what point restimulation becomes profitable, or if it is even economically feasible.

For a one-well lease there is less doubt as to when a well has reached a point where it needs stimulation. This is a "sink or swim" proposition. With a two-well lease, the choice is more complicated. Multiple-well leases present complex problems, for example a 20-well lease producing into a common battery. For such, it's easy to see that well testing is necessary to pinpoint workovers. It isn't so easy to see the necessity of well testing in reservoirs that do not show decline. However, in order to determine individual well decline or reduced capacity, periodic information is needed.

Reserve Estimates

Well test data are becoming increasingly useful in forecasting reservoir size, presence of inter-well communication and oil reserves.

Consider an oil reservoir. For a one-well reservoir, rate decline is easy to follow. However, for multi-well reservoirs a similar well may fall below its economic limit masked by the performance of the rest of the wells. Good well records and periodic tests will pinpoint or even anticipate the behavior of the problem well. The performance of such a well may serve as a guideline for wells completed later in the reservoir. Knowing the pore volume drained by the earlier well, calculated from well test data, will determine the need and spacing of later wells. Also, such testing will prove or disprove a well requiring treatment or abandonment, preventing its poorer performance from adversely affecting the economics of the lease.

For gas reservoirs, initial tests determine market hookup, sales contracts and field rules. Later tests allow for redetermination of assigned well reserves especially if larger reserves are indicated. Above all, regulatory control often involves the Federal Power Commission whose requirements for well tests and other data are legion. All-in-all the field man should appreciate and provide the most reliable data possible.

Need for Proper Well Test Procedures and Methods

Close cooperation between the staff engineer and field personnel will help establish appropriate specifications, rules and procedures for running well tests. It is the engineer's responsibility to know just what data are needed, and the field man's responsibility to provide the best possible data so required. Such an approach would build an "espri-de-corps" between staff and field personnel, uniformity and reliability of the test and a clearer interpretation of what the data really are saying.

For example, consider a field measurement of API oil gravity. If oil gravity reads 34°API at 88°F, true gravity is 34°API at 60°F. The simple omission of sample temperature data could cause the gravity to be misread at 36° with a 2¢/barrell/API° penalty. Similarly, suppose the sample read 36°API but the technician failed to note or report water in the sample. Water in the sample increases gravity. If the sample contained 1-1/2 per cent water (at 36°F) its correct gravity is 37°API, a 2¢/barrel/API° penalty. In the early days of oil, a gauger occasionally misread his tape and spent considerable time trying to figure out his daily runs. This may be amusing, but consider how serious an error results from recording the wrong orifice plate size for a gas test.

Preservation of data is also very important. "Hip-pocket" bookkeeping is risky. For example, pressure recordings are easy to lose since they aren't usually required by any regulatory body.

PROPER WELL TEST DATA GATHERING

The various uses of well test data have been discussed elsewhere in this paper. Correct reservoir analyses depend upon well tests and, therefore, the proper method of exploiting the reservoir for maximum economic benefit rests directly on test data obtained by field personnel. Often a possible profit of several millions of dollars is involved.

When a request for field test is made, the person initiating the request assumes it will be conducted according to his instructions or according to standard procedure. Unless the information he receives is obviously in error, he will accept it as being accurate. To merit this trust several conditions must be met.

The mechanical equipment used in the test must be accurate, properly calibrated, and operative. This equipment includes orifice meters, chart drives, dynamometers, orifice plates, chokes and pressure measuring devices. Equipment often taken for granted and not checked for proper operation during a well test include separators, water knockouts and treaters. The story is told of a junior engineer conducting a production test on a gas-condensate well on a very cold day. Production was being taken through a separator which recovered the liquids and dumped them into a storage tank. The gas was being measured and then flared. After the test had been going for several hours, it was discovered that the liquid dump valve was frozen. He had taken for granted that the separator was operating properly. The test would have been erroneous if an experienced field tester had not accidentally come by.

Personnel conducting tests must be familiar with all the equipment involved and be proficient in its operation. They must have an understanding of any charts or tables used. A good illustration of the mistakes which can be made in this regard occurred recently in the Pennsylvanian producing trend of New Mexico. These wells generally produce with a very high fluid volume and a high water-cut. The amount of water being produced is generally gauged by means of a "bucket test." The test is conducted by simply measuring the time required to fill a bucket with water. One service company publishes a table which converts the time to barrels of water per day. One operator was using a five-gallon bucket. The conversion chart was calculated for a four-gallon bucket; therefore, all water production reported by this operator was 25 per cent lower than actually produced. At the fluid rates involved, the error could amount to as much as 150 to 200 barrels per day.

The well to be tested must be isolated from any effects from other production. To do this it is often necessary to shut in another well or wells producing into common flow lines or separators.

Test records should reflect all significant events or changes during the test. Malfunctions of any equipment or instrument used should be documented. Figure 19 presents data on an interference test which could not be interpreted. There were three wells, each owned by a different operator, completed in what appeared to be a single reservoir. An interference test was run to confirm this interpretation. In the observation well, when all wells were shut in, the pressure built up as expected. When Well No. 1 was put on production, the pressure at the observation well began to decline showing good communication. At point B when Well No. 2 was put on production, the pressure at the observation well continued to fall until it reached point C, at which time the pressure began to increase for no apparent reason. After approximately four weeks of discussions among the various operators and a detailed questioning of all personnel involved in the field operations and test, it was discovered that Well C was on production only a very short time before a mechanical malfunction caused the well to be shut in. A lot of unnecessary time was wasted because adequate records were not kept during the testing period.

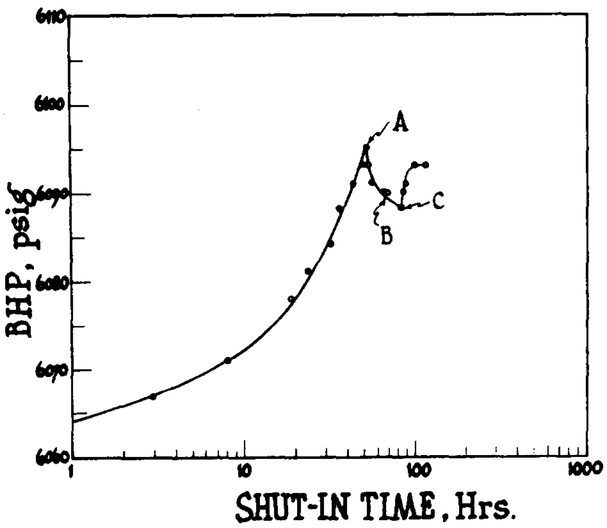

FIGURE 19

Example of pressure-buildup interference. Without careful checking and persistant effort the reason for interference would not have been discovered. One well was inadvertently shutin prior to test.

Probably the most important single factor in a well test is to make sure that the well has reached a stabilized condition. In a production test this requires that the well be produced at a constant rate until the pressure transients have reached the drainage boundary of the well. Prior to conducting a buildup test, the well should be produced at a constant rate until the pressure transients are stabilized. Figure 20 is an example of a gas well back-pressure test which yielded no usable data because the flow periods were not long enough to reach stabilization.

Well tests should be extended until it is certain that the required data have been obtained. If the recording of data is not started soon enough, or if the test is cut short, valuable information can be lost and the data recorded is often useless. Our job is to find oil and to produce it. As a result it is often difficult to justify the time and expense required to obtain well test data. This is particularly true of any test which requires that a well be shut in. The longer the shut-in period, the more unpopular the test. If the test is worthwhile, it is important that good information be gained. Figure 21 illustrates a well test which failed to provide any

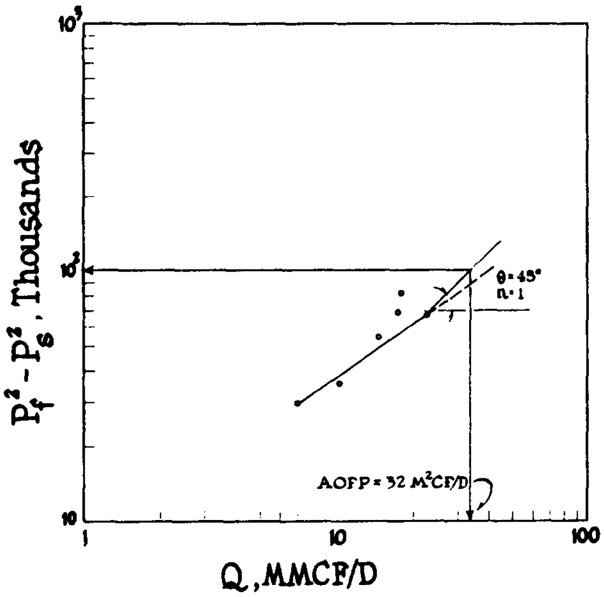

FIGURE 20

An example of a back-pressure test for which no usable data were obtained. Stabilized conditions were not reached at any test flow rate (West Texas example).

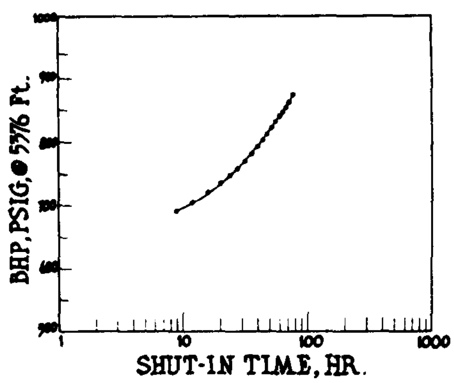

FIGURE 21

Pressure-buildup test started too late to obtain early-time data that would reveal completion efficiency and ended too soon to obtain midde-time information for reservoir evaluation (Permian Basin example).

usable information. Pressure measurements were started after nine hours and, therefore, the early data which would show the efficiency of the completion was lost. On the other end of the curve, the test was stopped before the definitive part was reached. About the only positive information obtained was that the reservoir pressure was in excess of 870 psi.

SIGNIFICANCE OF DATA IN DETERMINING WELL TREATMENTS

Introduction

Reservoir operations may realistically be thought of as a series of well treatments and well operations. As such, a well must be considered from a reservoir viewpoint, intelligently diagnosing the problem in planning remedial action. These problems fall into four critical categories: (1) limited production rate, (2) excessive water production, (3) excessive gas production, and (4) mechanical problems.

Limited producing rate is usually due to one or a combination of low reservoir permeability, low reservoir pressure, formation damage, wellbore or tubing plugging, high oil viscosity, excessive formation back-pressure, and inadequate artificial lift.

Permeability reduction may be the result of mud filtrate invasion, scale, paraffin, perforating gun debris or formation block creating skin damage, requiring well stimulation treatment. On the other hand, such alteration may be simply a natural consequence of the reservoir. To differentiate between formation damage and normal productivity decline, reservoir studies, including transient pressure testing, are in order.

Excessive back-pressure on the formation may be the result of plugged perforations, subsurface or surface chokes, undersized lines or separators.

Inadequate artificial lift may result due to one or a combination of the following:

1. Operational problems with rod-pumped wells:[6]
   a. pump set too high
   b. pump gas-locked
   c. defective tubing or pump
   d. inadequate balance of pumping unit
   e. improper time cycle
   f. high back-pressure on well
   g. scale or paraffin in pump or tubing
2. Operational problems in gas lift:
   a. leaky valves or tubing
   b. improper time cycle
   c. inadequate design for current well condition
   d. high back pressure on well
   e. scale or paraffin in valves, tubing or perforations.
3. Operational problems in hydraulic pumping wells:
   a. inadequate design
   b. defective equipment
   c. dirty power oil
   d. scale or paraffin in tubing

Water production problems are usually due to:

1. natural reservoir water-drive aggravated by fingering or coning
2. mechanical or well problems such as casing/tubing leaks, cement failure
3. fracturing and/or acidizing that causes intercommunication of oil and water zones.

Well Data Determines Need and Nature of Treatment

A major use of well data in reservoir operations has already been discussed, viz., prediction of remaining reserves. Another major use of such well data is in determining the need for and type of treatment.

At this point it is necessary to determine whether the affected well is suffering from a change in reservoir behavior or if the problem is mechanical and resides in the well itself. Field data are used almost exclusively in deciding whether or not the well requires remedial action.

Mechanical Problems

Usually, mechanical problems are anticipated first. This decision may be made in the field, based on field observations and reservoir/well history. The problem most often encountered in this regard is normal wear-and-tear on downhole equipment. A common repair is the replacement of a worn downhole pump. However, the characteristic that most often points to such mechanical difficulties is abnormal production decline which may, in turn, be due to particulate buildup of foreign matter on lift equipment. The most common particle buildup is scale or paraffin. Deciding which material has caused the buildup requires a working knowledge of the area and the behavior of adjacent wells. In a new reservoir, several well workovers may be required to develop enough field history to differentiate between scale and paraffin problems.

Other common mechanical problems, identifiable by field data, include tubular-goods failure and change in reservoir performance that dictate changes in downhole equipment. Tubular-goods failure is usually accompanied by a loss in production. An abnormal increase in water production and high fluid level points to a casing failure (in cased holes) or packer leakage (in open hole). Both conditions demand immediate attention via well workovers. Water breakthrough or oil response are identified by increases in fluid production (on well test) or an abnormally high fluid level (Sonolog) and usually require changes in downhole equipment. It should also be noted that increases in fluid level invite unwelcome formation back-pressure conditions.

Data Required

Suitable field tests include accurate well tests and carefully derived bottom-hole pressure tests. Such data can be readily incorporated into decline curve studies which may be used to spot abnormal decline. Such curves can be compared with similar data from surrounding wells to ascertain mechanical problems (e.g., worn pumps, plugged tubing) or changes in reservoir behavior.

Water analyses are quite valuable, especially in secondary recovery operations. Such tests should be made periodically, especially in artificial recovery projects to spot injection water breakthrough. In primary production, water analysis can aid in determining the presence, absence and even direction (source) of water encroachment.

The observer should also be wary of any changes or abnormalities in field operations, for example, spotting unusual downtime due to pumping unit or battery operation. These conditions would indicate more production than should be assigned to a given well, leading to erroneous data in reservoir calculations.

Field data are also useful in differentiating between normal production decline and skin damage. Both conditions are accompanied by pressure decline and change in relative permeability. The former is natural and expected; the latter is unexpected and undesirable. Periodic pressure surveys and PI tests usually indicate the normal pressure and productivity decline anticipated for the reservoir. A steady increase in gas-oil ratio or water-oil ratio (depending on whether the reservoir produces by solution gas-drive or water-drive) is also normal. Good performance curves will monitor this behavior. If such occurs, no remedial well work is necessary. Rather, extensive reservoir studies are in vogue to ascertain the need for a major change in reservoir operations by altering the natural drive with an artificial one, such as pressure maintenance, gas-cap injection or waterflooding. If field data follows such a course, many unnecessary and unsuccessful workovers are eliminated.

Skin damage may be the result of several causes, as previously mentioned. Of importance are formation damage problems resulting from the insidious buildup of scale and formation blockage or impairment. Scale formation damage can usually be spotted from a well performance curve. However, such behavior can easily be confused with a mechanical problem such as plugging (also causing an abnormal decline in well production); the true condition can be determined only by pulling the well. The absence of scale on tubing does not eliminate the possibility of scale on the formation. This problem can be treated by scale converter or acid treatments. Formation blockage usually occurs after a workover is completed or as a consequence of casing leakage. In this case, a change in relative permeability near the wellbore has occurred, preventing the well from returning to normal productivity. This is usually detected by abnormal reduction in anticipated fluid production. Such a condition may hopefully be corrected by using a reverse-wetting agent.

Data Desired

The same field data is used in spotting mechanical as well as reservoir problems and include suitable well tests, water analyses and good up-dated field history (e.g., adequate records on mechanical changes occurring in the field).

All these data must be carefully collected and utilized as the life of the project progresses.

Most of this information is irretrievable in point of time and space, irrevocably lost.

It can not be overstated that good data are very valuable and can turn defunct wells into good workover possibilities, poor wells into good wells and bad wells into abandoned wells. Good data can also guide the operator away from unnecessary workovers and maintain a more reasonable picture of a reservoir's natural decline.

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