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INTRODUCTION

Analysis of the performance of gas wells is an important part of the Petroleum Industry's operations. Gas well tests are used in regulatory work, various types of reservoir analyses, and in determining deliverability, or the capacity of a well to produce against a particular back-pressure. Historically, the capacity of gas wells to produce has been described in terms of the "open-flow" delivery rate or the "potential" of the well and the "shut-in pressure at the wellhead" or, less frequently, by some related quantity such as the "deliverability" at specified wellhead pressures. The open-flow capacity of a gas well is used for company operations, legal instruments such as contracts to buy or sell gas and governmental regulatory work. In the early days of the petroleum industry, the open-flow capacity of a gas well was measured directly. As this is a wasteful and hazardous practice, methods of calculating open-flow capacity from well tests made at reasonable and controlled rates of flow have been devised.

The first step toward calculating the open-flow potential or capacity of a gas well was made in the classic report of Rawlins and Schellhardt (1) which described, proposed, and explained the back-pressure method of determining the capacity of the gas well to produce under various conditions of back-pressure. This report was a milestone in the history of petroleum engineering and in the conservation of petroleum. These investigators analyzed data from 582 gas wells located throughout the United States. Specifically, they demonstrated that for the normal gas well, a plot of volume-rate-of-flow versus the difference between the square of the static reservoir pressure and the square of the corresponding flowing bottom-hole pressure on log-log paper is a straight line. Although the term "absolute open-flow potential" as used by Rawlins and Schellhardt represented the capacity of a well to produce against atmospheric pressure at the bottom of the well, the absolute open-flow will not be changed whether measured against atmospheric back-pressure or zero psia, because for most wells atmospheric pressure is negligible as compared to the shut-in sand face pressure. Rawlins and Schellhardt also devised a method of calculating the capacity of a well to produce against atmospheric pressure at the surface, i.e., the open-flow capacity, by taking into account the weight of the column of gas and the pressure drop due to frictional resistance in the flow string. In shallow wells producing through large-diameter flow strings, the absolute open-flow capacity and open-flow capacity are nearly equal because the pressure loss due to friction and the weight of the column of gas in the flow string is small or trivial in comparison to reservoir pressure. Since that time, the term absolute open-flow potential has been used and will be used in this manual to mean the rate of flow that would be obtained if the bottom-hole pressure opposite the sand face were reduced to zero psia; consequently, the absolute open-flow potential is independent of well equipment and represents the maximum productivity of the reservoir rock adjacent to a particular well.

(1) Rawlins, E. L., and Schellhardt, M. A., Back-Pressure Data on Natural Gas Wells and Their Application to Production Practice. U.S. Bureau of Mines, Monograph 7, 1935.

From a theoretical standpoint, the validity of Rawlins' and Schellhardt's findings can be supported by a consideration of the radial flow equation for gas. This equation, which represents the isothermal flow of gas in the steady state to a well bore in a symmetrical reservoir, can be stated as:

$$Q = \frac{C \pi KH (P_f^2 - P_s^2) T_b}{\mu P_b \ln \left[\frac{r_e}{r_w} \right] T_f Z} \qquad \text{I-1}$$

Where

- Q = flow to well, Mcf per day
- C = numerical constant to adjust units
- K = permeability of reservoir
- H = thickness of reservoir
- P_b = pressure base
- P_f = shut-in reservoir pressure
- P_s = flowing pressure at sand face
- T_f = formation temperature
- Z = average compressibility
- μ = average viscosity of the flowing gas
- ln = natural logarithm, i.e. logarithm to the base "e"
- r_e = drainage radius of well
- r_w = well-bore radius
- T_b = temperature base

For a particular well, the terms C, K, H, T_b, μ, P_b, ln r_e/r_w, T_f, and Z may be considered constant and thus can be combined into a single well constant, "C", which reduces the flow equation to: $Q = C (P_f^2 - P_s^2)$. This equation assumes isothermal steady state streamline flow and requires an average compressibility factor. As neither of these assumptions holds absolutely true in a gas reservoir, an exponent, "n", must be introduced to match actual field conditions. The formula then becomes: $Q = C (P_f^2 - P_s^2)^n$. This is the formula developed by Rawlins and Schellhardt. (For a "perfect" gas under isothermal steady state streamline flow, n = 1.) For a specific well and reservoir, "n" must be determined by measuring Q, P_f, and P_s under several different conditions and then solving for "n". By writing the equation as: $\log Q = \log C + n \log (P_f^2 - P_s^2)$ it can be seen that Q plotted versus $P_f^2 - P_s^2$ on log-log paper is a straight line with a slope of "n". To determine the absolute open-flow potential of a well, the measured points are plotted on log-log paper and the straight line is extrapolated to a point where $P_f^2 - P_s^2 = P_f^2$ (in other words $P_s = 0$). "Q" read at this point is the absolute open-flow potential. The flow rate at other conditions of back pressure can also be determined by calculating $P_f^2 - P_s^2$, using the desired P_s and reading Q at the corresponding point.

Rawlins and Schellhardt considered the coefficient "C" and the exponent "n" to be constants for a particular well. This is apparently true for a well operating under stabilized conditions; however, later studies indicate that for wells producing from low permeability reservoirs, the coefficient "C" is a variable related to time and can be considered as a constant only with respect to a particular time.

In general, the exponent "n" varies for individual wells between the limits of 0.5 and 1.0 and it is generally accepted that back-pressure curves with exponents below 0.5 or above 1.0 are erroneous. From a theoretical standpoint, the variation of the exponent "n" between different wells has not been satisfactorily explained; however, many investigators under both laboratory and actual field conditions have demonstrated the reliability of the back-pressure equation.

The basic equation for calculating the absolute open-flow potential of a gas well uses bottom-hole pressures, whereas surface pressures are more frequently and easily obtained. The theory of calculating subsurface pressures from surface pressures is simple, namely that the closed-in static bottom-hole pressure is equal to the closed-in wellhead pressure plus the weight of the column of fluid and that the flowing bottom-hole pressure is equal to the flowing wellhead pressure plus the weight of the column of fluid plus the pressure differential required to overcome frictional resistance to the flow of the gas in the particular flow string.

Several methods of calculating subsurface pressures in gas wells have been developed. Rawlins and Schellhardt used Weymouth's formula for calculating the pressure drop due to frictional resistance. As no corrections were made for compressibility and as an average temperature of flow of 80°F was taken, this method, generally termed the U. S. Bureau of Mines method, is applicable only to shallow, low-pressure gas wells. The technique of computation for this method was improved and simplified by Ferguson (2) (3). As the use of the method was extended to deep, high-pressure gas wells, the earlier simplifying assumptions had to be modified. Vitter (4) adapted the method to condensate wells. The calculation techniques described in this manual are based in principle on this early work but incorporate recent modifications to obtain a procedure that is as simple as possible, consistent with accuracy.

Throughout this manual the pressure base is taken as 15.025 psia, and the temperature base is 60°F. All gas volumes are referred to these base conditions which are sometimes designated as standard volumes or standard conditions. If maximum accuracy is to be obtained, all flow data gathered for back-pressure tests

(2) Ferguson, J. William, Calculation of Back-Pressure Tests on Natural Gas Wells; Oil and Gas Journal, January 19, 1939. pp. 47-53.
(3) Ferguson, J. William, Calculation of Back-Pressure Tests; Oil and Gas Journal, May 7, 1942. p. 52.
(4) Vitter, A. L., Jr., Back-Pressure Tests on Gas-Condensate Wells; A. P. I. Drilling and Production Practice, 1942. pp. 79-87.

must be measured under stabilized conditions. With reference to the production of gas wells, the term "stabilized" is generally used in a manner to infer that at a constant flow rate the flowing conditions within the well bore have become constant and are thus unchanging with time. This condition, of course, can never be attained when a well is producing at a constant rate because the mass content of the reservoir is being continually reduced. Associated with the reduction in mass content must be a continual decrease in the pressure level throughout the reservoir. In view of this, the term "stabilized" when applied to well conditions associated with gas well production tests will be used to denote that further changes in pressure, gas-oil ratio, and rate of flow will be negligible and can be ignored for the purpose of calculating a back-pressure test.

The calculation techniques described in this manual can be divided into three categories: (1) stabilized multipoint back-pressure tests, (2) nonstabilized multipoint tests, and (3) surface tests. The stabilized multipoint back-pressure test procedure can be used in wells in which stabilized flowing conditions can be reached within a reasonable period of time. Prior to testing, the well should be flowed at sufficient rate and for a sufficient period of time to clear the well of accumulated liquids that might result in erroneous pressure data. After the well has been cleaned, it should be shut-in for a period long enough to permit the measurement of an accurate stabilized shut-in pressure. Normally, pressures are measured at four stabilized rates of flow for use in the equation: $Q = C\,(P_f^2 - P_s^2)^n$. In taking the flowing pressures, the flow rates should be sufficient to prevent the accumulation of liquids in the well bore. A wide variation in flow rates is desirable to achieve a good spread in data points and thus permit accurate extrapolation of the back-pressure curve.

Accurate wellhead temperatures are required in the calculation of subsurface pressures. Flowing temperatures can usually be measured accurately at the wellhead for each rate of flow; however, at low flow rates the observed wellhead temperature may be distorted by atmospheric conditions. When this situation exists, the mean annual temperature should be used as an approximation of the actual wellhead temperature. The static wellhead temperature usually cannot be measured accurately and in lieu thereof the mean annual temperature appropriate to the locality is sufficiently accurate for the computation.

The rates of flow during the tests should be accurately measured with acceptable metering devices; and the gas-liquid ratios, gas and liquid gravites, and other pertinent information should be obtained. It is good practice to plot the data points as they are obtained or, at least, plot the difference of the squares of the surface pressures to check for alignment and make sure the data are satisfactory and the well properly cleaned. This procedure often will indicate the condition of the test equipment and the well and make it possible to make adjustments immediately that could eliminate the necessity for a re-test. After the field data have been obtained, the results can be plotted on log-log paper, with Q shown on the abscissa and $P_f^2 - P_s^2$ on the ordinate. These points should fall in a straight line, the slope of which represents the reciprocal of "n". The absolute open-flow potential can then be determined by extrapolating the straight line graphically or by use of the back-pressure equation for which the numerical values of "n" and "C" are easily found.

Whenever stabilization cannot be reached within a reasonable period of time because of reservoir conditions, or when flow rates of sufficient duration to reach stabilized conditions are impractical, the slope of the back-pressure curve can be obtained by using one of two different procedures; namely, the constant-time multipoint test or the isochronal multipoint test. The constant-time multipoint test is identical to the stabilized test except that the duration shall be the same for each flow rate. The four points determined from the constant-duration flow tests can be used to determine the slope of the back-pressure curve. A line of this slope can then be drawn through the point determined from an extended flow test approximating stabilized conditions. The absolute open-flow capacity of the well is determined from this line. The precautions to be observed and the method of plotting the data are also identical to the stabilized test.

The isochronal multipoint test can also be used where it is not possible to obtain stabilized flow conditions. This procedure is based on the work of Cullender (5) which showed that the slope of the back-pressure curve can be obtained from data points taken prior to stabilization, providing that each flow rate is of the same duration and that each flow period starts from stabilized shut-in conditions. In making this test, the well is first cleaned and a shut-in pressure obtained in the same manner as would be done under stabilized conditions. Each flow rate following the shut-in pressure should be of the same duration; but, after each flowing pressure is observed, the well should be shut in until a reasonable constancy in pressure is achieved. In plotting the points, the shut-in pressure preceding each flow rate should be used in conjunction with the flowing pressure corresponding to that rate used in the calculation of $P_f^2 - P_s^2$. The points so calculated will determine the slope of the back-pressure curve. An extended flow test to obtain a flowing pressure approximating a "stabilized condition" is required to locate the position of the back-pressure curve. The curve is completed by drawing a line of the slope determined from the four constant-time points through the point plotted from the extended ("stabilized condition") test. The absolute open-flow capacity of the well is obtained from this line.

Redetermination of the absolute open-flow potential can be made by the "one-point" test procedure once the slope of the back-pressure curve has been established. This method assumes that the slope of the back-pressure curve does not change with time. Accordingly, a one-point test requires only that a shut-in pressure and one stabilized flow rate be obtained. The new value of

(5) Cullender, M. H., The Isochronal Performance Method of Determining the Flow Characteristics of Gas Wells; AIME Trans., V 204, pp. 137-142, 1955.

absolute open flow is determined by drawing the back-pressure curve through this point using the known slope. This determination can also be made by using the following equation:

$$AOF = Q \left[\frac{P_f^2}{P_f^2 - P_s^2} \right]^n \qquad \text{I-2}$$

These procedures require that the subsurface pressures be either measured or calculated. In shallow wells with large flow strings the differences between surface and subsurface pressures are usually small, and surface pressures can be used with little error. If the error introduced by using the surface pressures does not warrant the use of subsurface pressures, then the static column wellhead pressures can be substituted for the bottom-hole pressures. Surface pressures are used in determining the deliverability of a well or capacity of the formation to produce gas into the well bore against a specified surface pressure. The deliverability is calculated by solving for "D" in the following equation:

$$D = Q \left[\frac{P_c^2 - P_d^2}{P_c^2 - P_w^2} \right]^n \qquad \text{I-3}$$

Where

- D = deliverability of well at back pressure, P_d
- Q = rate of flow at a pressure of P_w, during test
- P_c = shut-in wellhead pressure

The ability of a well to produce into a gathering system can be determined for various wellhead pressures of the flow string corresponding to a specified line pressure after establishing a curve by first plotting Q versus $P_c^2 - P_t^2$ for several rates of flow in the same manner as is done for Q versus $P_f^2 - P_s^2$ in the standard back-pressure plot. Then the producing capacity of the well at a given back pressure can be read from the curve using the appropriate values of $P_c^2 - P_t^2$ or by replacing P_d and P_w in the deliverability equation with the corresponding pressures of the flow string and utilizing the exponent "n" established by the plot of Q versus $P_c^2 - P_t^2$. The plotted line may not be exactly straight but by restricting its use to those situations which require little extrapolation, the producing capacity can be determined with reasonable accuracy.