

Chapter 33

Open Flow of Gas Wells

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Introduction

The gauging or testing of gas wells arose from the need to measure the productive capacity of a well. The earliest response to this need was to open the well to flow to the atmosphere and then to measure the flow rate. However, it soon became apparent that such practices were wasteful of gas, dangerous for personnel and well equipment, and frequently damaging to the reservoir. In addition, such tests provided very little information for estimating production rates into a pipeline. As a result, the practice of gauging gas wells by opening the well to flow to the atmosphere decreased and now is almost completely confined to stripper gas areas where pressures are very low and the rates of flow are small.

Pitot-Tube Gauging of Low-Pressure Wells

The pitot tube is one of the simplest instruments for measuring the rate of flow of gas. As such, the pitot has been used extensively to obtain an approximate gauge of the open-flow capacity of low-pressure gas wells. The well is opened to flow to the atmosphere through a flow nipple, and the producing rate is measured with a pitot tube. The producing rate is influenced by the hydrostatic head of the column of flowing gas and the friction between the flowing gas and the walls of the flow string. Thus the observed rate of flow to the atmosphere may be a very close measure of the ability of shallow low-capacity reservoirs to deliver gas into the wellbore. However, it may be more nearly a measure of the flow capacity of the flow string in the case of a well producing from a high-capacity reservoir. This is especially true where the flow is through a small-diameter flow string.

Historically, gauging of wells with pitot-tube measurements has been useful in the drilling and completion of low-pressure gas wells. During the drilling of many wells in the Hugoton field of Kansas, Oklahoma, and Texas, it was the practice to take pitot gauges after

every bailer run or at the end of each 5 ft of formation drilled. Upon completion, data were available to construct a chart showing a relationship between the rate of flow and depth. The chart is useful in determining the depth of the major gas-producing zones. Such data were valuable in planning remedial work that may be necessary during the life of the well. Pitot-tube gauges were useful in determining rate-of-flow increases resulting from each stage of acid treatment. In many cases the pitot-tube gauge after acid treatment provided data from which the desired flow rates for a backpressure test could be selected.

Fig. 33.1 shows a pitot-tube and flow nipple arrangement that is suitable for gas measurement. The pitot tube should be made of 1/8-in.-ID pipe shaped to measure impact pressure at the center and in the plane of the opening of the flow nipple. The flow nipple should be at least eight pipe diameters long, free from burrs or other obstructions, and must be round. The impact pressures are measured with water or mercury manometers or a pressure gauge, depending on the pressure to be measured.

The impact pressure is converted to rate of flow by suitable equations or tables such as those published by Reid.¹ Subsequent experimental work by the USBM² is in reasonable agreement with the Reid data. The equations published by Reid were investigated by Binckley,³ who concluded that they were based on sound theoretical principles. Reid's equations and tables have been adjusted to a pressure base of 14.65 psia for the purposes of this handbook. The adjusted equations for impact pressures less than 15 psig are

$$q_g = 34.81 d_i^2 \sqrt{h_w}, \dots \dots \dots (1)$$

$$q_g = 128.4 d_i^2 \sqrt{h_m}, \dots \dots \dots (2)$$

and

$$q_g = 183.2 d_i^2 \sqrt{p_i}, \dots \dots \dots (3)$$

*This author also wrote the original chapter on this topic in the 1962 edition.

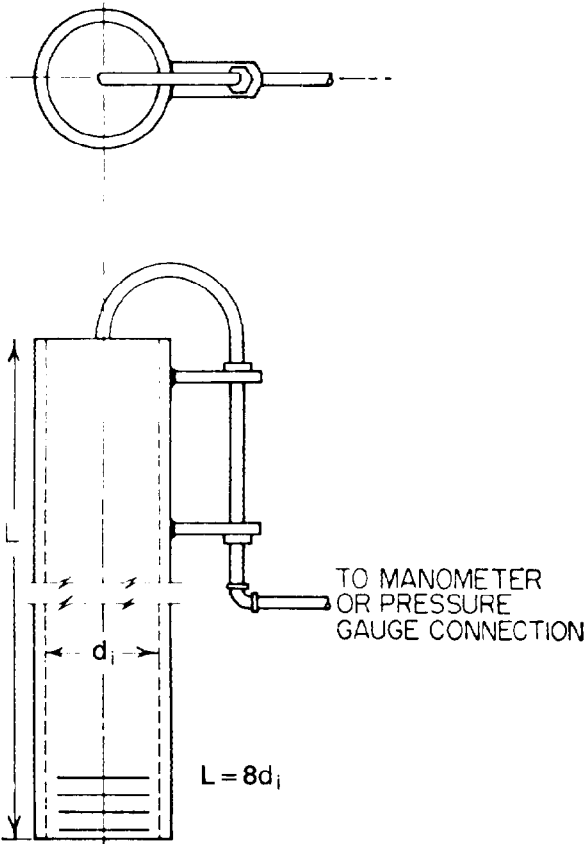


Fig. 33.1—Typical flow nipple and pitot tube for gas measurement.

where

- q_g = rate of gas flow, Mcf/D (14.65 psia and 60°F),
- d_i = ID of flow nipple, in.,
- h_w = height (manometer reading), in. water,
- h_m = height (manometer reading), in. mercury, and
- p_i = impact pressure, psig.

For impact pressures more than 15 psig, the adjusted Reid equation is

$$q_g = 23.89 d_i^2 p_1, \dots \dots \dots (4)$$

where p_1 is impact pressure, psia. Values of rates of flow for various impact pressures are given in Table 33.1 for a flow nipple with an ID of 1.000 in. Rates of flow in Table 33.1 were computed by Eqs. 1 through 3. The range of impact pressures is from 0.1 in. of water to 15 psig. Rates of flow for impact pressures from 15 to 200 psig were computed by Eq. 4 and are given in Table 33.2 for a flow nipple with an ID of 1.000 in. Impact pressures measured on larger flow nipples can be converted to rates of flow by multiplying the rate of flow from the table corresponding to the impact pressure by the square of the ID (in.) of the larger nipple.

Rates of flow taken from Tables 33.1 and 33.2 or computed by Eqs. 1, 2, 3, and 4 are for gases with a specific gravity of 0.600 (air = 1.000), flowing temperatures of

60°F, and for discharge into an atmospheric pressure of 14.65 psia. Corrections can be made when desirable by multiplying values from the equations or tables by the following factors.

$$F_g = \sqrt{\frac{0.600}{\gamma_g}}$$

and

$$F_T = \sqrt{\frac{520}{(460 + T_f)}}$$

where

- F_g = specific gravity correction factor,
- γ_g = specific gravity of gas being measured, air=1.000,
- F_T = flowing-temperature correction factor, and
- T_f = temperature of flowing gas, °F.

The atmospheric-pressure correction factor for values from Table 33.1 and Eqs. 1, 2, and 3 is

$$F_{bar} = \sqrt{\frac{p_a}{14.65}}$$

where F_{bar} is barometric correction factor and p_a is atmospheric pressure, psia. The value of pressure used for p_i in Eq. 4 is the absolute pressure and is computed by adding the barometric pressure to the gauge pressure. The correction factor for barometric pressure for Table 33.2 is

$$F_{bar} = \frac{p_i + p_a}{p_i + 14.65}$$

In ordinary usage, rates of flow are taken from pitot tables or formulas without correction.

Example Problem 1. Given an impact pressure of 27.2 in. of water on a flow nipple with ID=2.441 in., determine the rate of flow.

Rate of flow from Table 33.1 for ID = 1.000 = 182 Mcf/D.

Rate of flow for ID = 2.441 in. is

$$q_g = 182(2.441)^2 = 182 \times 5.958 = 1,080 \text{ Mcf/D.}$$

Or, by Eq. 1, the rate of flow is

$$\begin{aligned} q_g &= 34.81(2.441)^2 \sqrt{27.2} \\ &= (34.81)(5.958)(5.215) = 1,080 \text{ Mcf/D.} \end{aligned}$$

Example Problem 2. Given an impact pressure of 65 psig on a flow nipple with ID=4.082 in. with discharge into a barometric pressure of 13.2 psia, determine the rate of flow.

Rate of flow from Table 33.2 for ID of 1.000 and atmospheric pressure of 14.65 psia is 1,904 Mcf/D.

For ID of 4.082 in. and barometric pressure of 13.2 psia, the rate of flow is

$$\begin{aligned} q_g &= 1,904(4.082)^2 (65 + 13.2) / (65 + 14.7) \\ &= (1,904)(16.663)(0.9812) = 31,100 \text{ Mcf/D.} \end{aligned}$$

Or by Eq. 4,

$$q_g = 23.89(4.082)^2(65 + 13.2) = 31,100 \text{ Mcf/D.}$$

Backpressure Testing

Before the development of the backpressure method for testing gas wells, the open-flow capacities of gas wells were determined by actual "open-flow" tests. The flowing of wells at their wide-open rate results in waste and possible damage to the well. In addition, the open-flow

test yields very little information regarding the capacity of a well to deliver gas into a pipeline system.

The backpressure method of testing gas wells was developed by Rawlins and Schellhardt.² Results of tests on 582 wells as reported in their study and other work on many wells reported elsewhere show that when the rates of flow are plotted on logarithmic coordinates against corresponding values of $(\bar{p}_R^2 - p_{wf}^2)$ —the difference of squares of the shut-in pressure \bar{p}_R and the flowing sand-face (bottomhole) pressure (BHP) p_{wf} —the relationship may be represented empirically by a straight line.

TABLE 33.1—RATES OF FLOW FOR IMPACT PRESSURES LESS THAN 15 PSIG MEASURED WITH A PITOT TUBE FOR FLOW NIPPLE WITH ID = 1.000 in.*

Impact Pressure			$q_g, 10^3 \text{ cu ft/D}$ (14.65 psia and 60°F)	Impact Pressure			$q_g, 10^3 \text{ cu ft/D}$ (14.65 psia and 60°F)
Water (in.)	Mercury (in.)	psig		Water (in.)	Mercury (in.)	(psig)	
0.1	—	—	11.0	10.9	0.80	—	115
0.2	—	—	15.6	12.0	0.88	—	121
0.3	—	—	19.1	12.2	0.90	—	122
0.4	—	—	22.0	13.9	1.02	0.5	130
0.5	—	—	24.6	15.0	1.1	—	135
0.6	—	—	27.0	16.3	1.2	—	140
0.7	—	—	29.1	17.7	1.3	—	146
0.8	—	—	31.1	19.0	1.4	—	152
0.9	—	—	33.0	20.4	1.5	—	157
1.0	—	—	34.8	21.8	1.6	—	162
1.25	—	—	38.9	24.5	1.8	—	172
1.36	0.10	—	40.6	27.2	2.0	1.0	182
1.6	0.12	—	44.0	29.9	2.2	—	190
1.8	0.13	—	46.7	32.6	2.4	—	199
2.0	0.15	—	49.2	—	2.6	—	207
2.2	0.16	—	51.6	—	2.8	—	215
2.4	0.18	—	53.9	—	3.0	1.5	222
2.7	0.20	—	57.2	—	3.2	—	230
3.0	0.22	—	60.3	—	3.4	—	237
3.5	0.26	—	65.1	—	3.6	—	244
4.1	0.30	—	70.5	—	3.8	—	250
4.5	0.33	—	73.8	—	4.0	2.0	257
5.0	0.37	—	77.8	—	4.2	—	263
5.4	0.40	—	80.9	—	4.4	—	269
6.0	0.44	—	85.2	—	4.6	—	275
6.8	0.50	—	90.8	—	4.8	—	281
8.2	0.60	—	99.7	—	5.0	2.5	287
9.0	0.66	—	104.4	—	5.2	—	293
9.5	0.70	—	107.3	—	5.4	—	298
10.0	0.74	—	110.1	—	5.6	—	304
5.8	—	—	309	—	15.3	7.5	502
6.0	3.0	—	314	—	16.3	8.0	518
6.5	—	—	327	—	17.3	8.5	522
7.0	3.5	—	340	—	18.3	9.0	549
7.5	—	—	352	—	19.3	9.5	564
8.0	4.0	—	363	—	20.4	10	580
8.5	—	—	374	—	22.4	11	608
9.0	4.5	—	385	—	24.4	12	634
9.5	—	—	396	—	26.5	13	661
10.0	—	—	406	—	28.5	14	677
10.2	5.0	—	410	—	30.5	15	710
11.2	5.5	—	430	—	—	—	—
12.2	6.0	—	448	—	—	—	—
13.2	6.5	—	466	—	—	—	—
14.3	7.0	—	486	—	—	—	—

*Multiply rate of flow from table by the square of the diameter for flow nipples with ID's more than 1,000 in.

TABLE 33.2—RATES OF FLOW FOR IMPACT PRESSURES, 15 TO 200 PSIG, MEASURED WITH A PITOT TUBE FOR FLOW NIPPLE WITH ID = 1.000 in.*

Impact Pressure (psig)	$q_g, 10^3$ cu ft/D (14.65 psia and 60°F)	Impact Pressure (psig)	$q_g, 10^3$ cu ft/D (14.65 psia and 60°F)
15	710	40	1,307
16	733	45	1,426
17	757	50	1,546
18	781	55	1,665
19	805	60	1,785
20	829	65	1,904
21	853	70	2,023
22	877	75	2,143
23	901	80	2,262
24	925	90	2,501
25	948	100	2,740
26	972	110	2,979
27	996	120	3,218
28	1,020	130	3,457
29	1,044	140	3,697
30	1,068	150	3,935
32	1,116	160	4,174
34	1,163	170	4,412
36	1,211	180	4,651
38	1,259	190	4,890
		200	5,129

*Multiply rate of flow from table by the square of the diameter for flow nipples with ID's more than 1.000 in.

The backpressure method of testing wells requires that a series of flow rates and corresponding pressure measurements be obtained under stabilized conditions or at certain fixed time intervals. Testing under stabilized pressure and rate-of-flow conditions or according to a fixed time interval has become known as multipoint or "flow-after-flow" backpressure testing.

As the original backpressure or multipoint method came into general use, it became evident that the method of testing was applicable to those wells that approached stabilized producing conditions within a relatively short time. However, performance characteristics could not be determined by this method for wells that approached stabilized producing conditions slowly over a considerable period. This characteristic of slow stabilization has been associated generally with wells producing from reservoirs with low permeability and resulted in the development of the isochronal method of backpressure testing by Cullender.⁴

The procedure used to obtain the necessary performance data for the isochronal testing method is to open the well from a shut-in condition and allow the well to flow without disturbing the rate by changing the mechanical adjustment of chokes or valves for a specific period of time. The well is then shut in and allowed to return to a shut-in pressure comparable with that existing before the well was first opened, after which the well is again opened at a different rate of flow. In isochronal testing, each rate of flow starts from a comparable shut-in condition, which provides a means of maintaining a simple pressure gradient throughout the drainage area of the well during testing. The isochronal method of testing

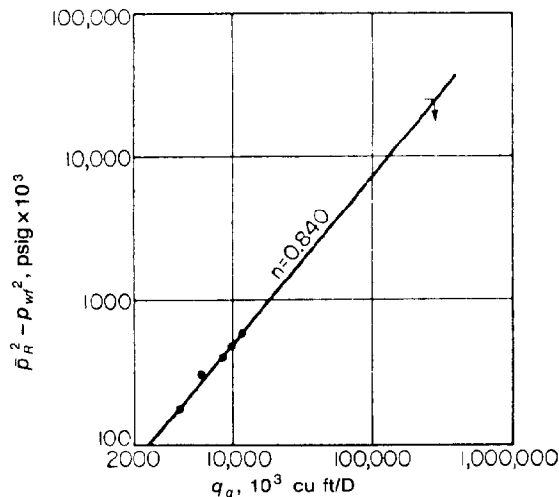


Fig. 33.2—Multipoint test showing bottomhole performance for Well B.

is especially suitable for determining the performance characteristics of wells producing from reservoirs with low permeability.

High-Pressure Gas and Gas-Condensate Wells

All the instructions for testing wells in this chapter apply to gas wells that produce a single-phase gas into the wellbore or to wells that are predominantly gas wells and the fluid flowing in the reservoir has a high in-place gas/liquid ratio (GLR). However, these methods for testing gas wells have been applied to high-ratio oil wells with some degree of success.

The chief difference between testing methods for high-pressure gas and gas-condensate wells and low-pressure wells is the care used in taking the data and methods used in computing the results. The effect of liquids is usually more pronounced in high-pressure than in low-pressure wells. Consequently, special care should be used to measure GLR's in high-pressure wells. Often it is necessary to determine the GLR at each rate of flow during a backpressure test. If the ratio was not constant during testing, the well probably was accumulating liquid in the wellbore during testing or unloading liquid. In either case the test is probably not acceptable and the well should be cleaned by flowing at a high rate and retested at rates of flow high enough to keep the well free of liquid.

Temperature effects during testing of high-pressure wells may be troublesome in interpreting test results. For example, Well B (Fig. 33.2) has a shut-in wellhead pressure of 4,173 psia at a wellhead temperature of 117°F. Maximum wellhead pressure was observed 3 minutes after the well was shut in. If wellhead pressure has been observed for an extended period of time, the wellhead pressure would have decreased to about 4,140 psia. The decrease in wellhead pressure is caused by the cooling of the gas in the well. In general, better tests can be obtained on such large-capacity wells if the testing is done after a preflow period. The preflow period should be run long enough to bring wellhead temperatures to a normal operating range of temperature. Wellhead

temperatures should be recorded during testing at periodic intervals so that actual measured temperatures can be used in computing subsurface pressures by methods outlined under Example 3 in the section on computing subsurface pressures.

Official Testing

Official testing of gas wells for state *regulatory bodies* is usually a multipoint test of short duration. In addition to the multipoint test, a single rate of flow for a period of 24 to 72 hours is required in some cases. The tester is referred to the test manuals of the various states, provinces of Canada, or appropriate countries for exact procedures, and no attempt is made here to outline official testing.

Backpressure Equations

In either multipoint or isochronal backpressure testing, the rates of flow and the corresponding values of the difference of squares of the average formation (reservoir) pressure \bar{p}_R and the sandface pressure [bottomhole flowing pressure (BHFP)] p_{wf} are plotted on logarithmic coordinates and a straight line is drawn through the points. The equation for the relationship is

$$q_g = C(\bar{p}_R^2 - p_{wf}^2)^n, \dots\dots\dots (5)$$

where the performance coefficient is represented by C and the exponent of the backpressure curve by n . The industry by common usage has referred to n as the "slope" of the backpressure curve, even though n is the reciprocal of the mathematical slope of the line. Here n is referred to as the "exponent" of the backpressure curve. Eq. 5 is an empirical relationship for both the multipoint test and the isochronal test and has resulted from the study of results of many tests. Values of the exponent vary for individual wells in the range of 0.5 to 1.0. Tests that result in exponents less than 0.5 or more than 1.0 should be rerun. Exponents of less than 0.5 resulting from multipoint tests may be caused by the slow-stabilization characteristics of the reservoir or by the accumulation of liquids in the wellbore. Exponents greater than 1.0 may be caused by the removal of liquid from the well during testing or by a cleaning of the formation around the well, such as the removal of drilling mud or stimulation fluids. Also, a multipoint test run in decreasing rate sequence may have an exponent of more than 1.0 for wells in slow-stabilizing reservoirs. Erratic exponents in isochronal testing are caused by either accumulation or cleaning of liquids from around the well. Erratic alignment of data points from multipoint or isochronal testing is usually caused by changes in actual well capacity during testing. Such changes may be caused by accumulation of liquids or the cleaning of the wells. The effects of the liquids in the well on multipoint testing have been given in detail by Rawlins and Schellhardt.²

Eq. 5 represents the capacity of a well to deliver gas into the wellbore, and it is useful especially in evaluating reservoir conditions. The capacity of a well to deliver gas at the wellhead may be represented by

$$q_g = C(p_{is}^2 - p_{wf}^2)^n, \dots\dots\dots (6)$$

where C , the performance coefficient, and n , the exponent, are different from those in Eq. 5 for a given well. p_{is} and p_{wf} represent wellhead shut-in (static tubing) pressure and working (flowing tubing) pressure on the flowing-gas column at the wellhead, respectively. Eq. 6 is useful especially in estimating the capacity of a well to deliver gas into a pipeline under specified conditions.

Gas Well Inflow Equation, Pseudosteady State

Reservoir engineers have realized for many years that interpretation of multipoint and isochronal tests by means of Eq. 5 gave no insight into the effect of reservoir or gas properties on the rate of flow into a well. Thus, Eq. 5 proved inadequate for reservoir engineering purposes. An equation that describes the pseudosteady-state flow of gas into a well has been presented in the literature.⁵⁻⁸ It is

$$q_g = \frac{703 \times 10^{-6} k_g h (\bar{p}_R^2 - p_{wf}^2)}{\mu_g T_R z (\ln r_e / r_w - 0.75 + s + F_{nD} q_g)}, \dots\dots\dots (7)$$

where

- q_g = gas-production rate, 10³ cu ft/D,
- k_g = permeability, effective to gas, md,
- h = formation thickness, ft,
- \bar{p}_R = average reservoir pressure, psia,
- p_{wf} = flowing bottomhole pressure, psia,
- μ_g = gas viscosity, cp,
- T_R = reservoir temperature, °R,
- z = compressibility factor of gas,
- r_e = effective drainage radius, ft,
- r_w = wellbore radius, ft,
- s = skin factor, and
- F_{nD} = non-Darcy flow factor.

If we let

$$\frac{703 \times 10^{-6} k_g h (\bar{p}_R^2 - p_w^2)}{\mu_g T z} = C_1,$$

and

$$\ln r_e / r_w - 0.75 + s = C_2,$$

Eq. 7 becomes

$$q_g = \frac{C_1}{C_2 + F_{nD} q_g},$$

or

$$F_{nD} q_g^2 + C_2 q_g - C_1 = 0.$$

From this we get

$$q_g = \frac{-C_2 + \sqrt{C_2^2 + 4F_{nD} C_1}}{2F_{nD}}, \dots\dots\dots (8)$$

The maximum rate of flow [open-flow potential (OFP)] is given when C_1 is a maximum—that is, when $p_{wf} = 0$. Eq. 7 incorporates the properties of the reservoir and the gas and can be extended to noncircular areas as given in Ref. 5.

Determination of Absolute Open Flow (AOF)

The terms "calculated absolute open flow" (CAOF) and OFP are the rate of flow in thousands of cubic feet of gas per 24 hours that would be produced by a well if the pressure against the face of the producing formation in the wellbore were zero. The value of the OFP is usually determined graphically by plotting rates of flow q_g against the corresponding values of $\bar{p}_R^2 - p_{wf}^2$. The straight-line relationship between q_g and $\bar{p}_R^2 - p_{wf}^2$ is extended so the rate of flow q_g corresponding to the value of \bar{p}_R^2 can be read by extrapolation. Then q_g is the AOF of the well in cubic feet per 24 hours. The AOF can be computed from Eq. 5 or read directly from plotted relationships.

In wells producing from reservoirs with low permeability, the reported AOF must be identified further by the time involved in the test and the type of test. For example, the OFP of such a well as determined by a 3-hour multipoint test (each rate of flow lasting 3 hours) would be less than that determined by a 2-hour multipoint test. The open flow determined by an isochronal test of 3 hours would be different from that determined by a multipoint test. A good example of the relationship between AOF and type of test is given by Cullender.⁴ Reported OFP's on wells in low-permeability reservoirs are more or less meaningless without an indication of the type of test involved.

Determination of the Exponent n

The calculation of the exponent n is based on Eq. 5 and the relationship

$$n = \frac{\log q_{g2} - \log q_{g1}}{\log(\bar{p}_R^2 - p_{wf}^2)_2 - \log(\bar{p}_R^2 - p_{wf}^2)_1} \dots \dots \dots (9)$$

Values of q_g and corresponding values of $\bar{p}_R^2 - p_{wf}^2$, either actual experimental points or values read from the straight-line relationship, are substituted in Eq. 9. Usually the data points do not fall exactly on a straight line; so the best practice is to read values of q_g and $\bar{p}_R^2 - p_{wf}^2$ directly from the straight line.

Determination of the Performance Coefficient C

After the value of the exponent n has been determined, the value of the performance coefficient C may be determined by substitution of a corresponding set of values for q_g and $\bar{p}_R^2 - p_{wf}^2$ and the value of n into Eq. 5. The value of C is found by solution of the resulting equation. Graphically the value of C may be determined by extension of the straight-line relationship to $\bar{p}_R^2 - p_{wf}^2 = 1$ and reading the corresponding q_g . When $\bar{p}_R^2 - p_{wf}^2$ is unity, C is equal to q_g . In practice, a determination of the value of C is seldom necessary for routine analysis of backpressure tests.

Preparation of Well for Testing

The wellbore should be cleaned of liquids by flowing at a high rate to a pipeline for a period of 24 hours. If the well does not have a pipeline connection, it may be blown to the air for a short period of time, provided blowing is considered safe. Extra precautions should be taken on new wells to remove drilling mud, solids, and stimulation fluids from the wellbore. The well should be shut in

for 24 hours or longer to equalize the reservoir pressure in the vicinity of the well. Wells with slow pressure-buildup characteristics should be shut in 48 to 72 hours, if possible.

While the well is shut in, the gas-measurement equipment should be prepared for use. If the gas is to be measured with an orifice meter, the meter should be calibrated, the diameters and condition of the run and plate verified, and the differential pen should be zeroed in accordance with good meter practice. If a critical-flow prover (see later section on gas measurement) is used, it should be placed in a vertical position at the wellhead or downstream from the separator so that the gas will flow up and away from the test area. If a separator is used, control the rate of flow with a production choke and maintain pressure on the separator with a critical-flow prover or backpressure regulator when an orifice meter is used. If a separator is not used, control rate of flow and pressure at the wellhead with the critical-flow prover. Always install thermometer wells at the wellhead and at gas-measuring equipment so that temperatures may be measured with a thermometer or calibrated recording device. The thermometer wells should be filled with water or oil to obtain accurate temperature measurement.

Shut-In Pressure

All shut-in or flowing pressures should be measured with a dead-weight or piston gauge, because spring gauges are usually not accurate enough for backpressure tests. Determine and record the pressure at the end of the shut-in period, prepare the well for testing, and redetermine the shut-in pressure as a check on the first measurement and to obtain the rate of pressure buildup. Report each pressure and time the well was shut in prior to each pressure measurement. After the second pressure measurement, either the isochronal or multipoint test may be started.

Subsurface pressures in gas wells may be measured directly with pressure gauges or computed from wellhead pressures. Subsurface-pressure gauges are very useful in wells where liquids accumulate in the wellbore during shut-in. However, the use of subsurface gauges limits the rates of flow during the backpressure test to velocities that will not lift the gauge in the flow string. The use of subsurface gauges is limited to rather low rates of flow in 2 3/8-in. OD tubing, but there is practically no limitation on their use in 7-in. casing. The use of subsurface gauges in the annular spaces of dual completions is practically impossible. In cases where large-capacity wells are being tested, correction must be made for the effect of hysteresis on gauge readings, or the BHP must be measured at each rate of flow by a separate run of the gauge.

The accumulation of liquid in the wellbore is probably the most serious cause of erroneous calculated BHP's. Other sources of error are uncertainties in temperature gradients and specific gravities of the fluids flowing in the well. Before a backpressure test is begun, special care should be taken to remove the liquids from the wellbore by flowing at rates large enough to lift the liquid. If possible, each rate of flow used in the backpressure test should be large enough to lift continuously any liquid that may move into the wellbore during production. Temperature gradients can be

established for a new area only by actual measurement. Usually a flowing-temperature gradient can be estimated by assuming a straight-line gradient between flowing wellhead temperature and bottomhole temperature. Uncertainty in the specific gravity of the fluid flowing in the well can be eliminated to a large degree by careful measurement of gas/hydrocarbon liquid ratio and determination of the specific gravity of the separator gas, separator liquid, and stock-tank liquid.

Multipoint Test and Example

A four-point multipoint test of constant duration for each rate taken in increasing rate sequence is normally satisfactory for establishing the performance of a well. In the case of high-liquid-ratio wells or high-flowing-temperature conditions, a decreasing-rate-sequence test may be used if an increasing-rate-sequence test would not result in alignment of points. In the case of high-liquid-ratio wells, the low flow rates will not clean the wellbore of liquids that accumulate during production. In the case of wells with exceptionally high flowing temperature, it may be desirable to start the test at the highest rate of flow that will result in more nearly constant wellhead temperatures during the test rather than starting at the lowest rate of flow. However, a test in decreasing-rate sequence should not be run unless it is known that an increasing-rate-sequence test will not give a satisfactory test.

The four rates of flow for the test should be evenly distributed over the test range. For average- to low-capacity gas wells, the first rate of flow should lower the pressure at the wellhead about 5%, and the pressure reduction for the fourth rate should be 25%. The rate of flow required to reduce the working pressure to 5% for the first test rate can be approximated from pressure readings obtained while the well is being cleaned before the well is shut in. These recommended pressure reductions may not be possible for large-capacity wells with large flow strings.

After the well is opened for the first rate of flow, the test rate should be continued for 3 hours but no more than 4 hours. Each succeeding flow rate should be for the same period of time. During each flow rate, the wellhead working pressure and temperature, meter or prover pressure and differential, and temperature should be reported at the end of each 15-minute period. If separator and tanks are used during testing, the rate of liquid accumulation, both hydrocarbon and water, should be reported. If a critical-flow prover alone is used, the presence or absence of liquids in the gas stream should be noted and reported. The specific gravity of the separator gas or the specific gravity of the gas flowing from the critical-flow prover should be measured and reported, or a gas sample should be taken for analysis and calculation of the specific gravity. More representative gas specific gravities can be obtained after the well has been flowing at least an hour.

Table 33.3 is an actual copy of the field data sheet for a multipoint backpressure test for Well A in the Guymon Hugoton gas field in Texas County, OK.* The form on which the data are reported has proved convenient for recording test data. The times at which each plate was

changed and when the well opened on each rate of flow were carefully reported. The "remarks" column gives the results of the specific-gravity measurement and the condition of the flow with regard to whether the well was producing water. All the observations recorded in Table 33.3 are necessary for accurate analysis of test results.

Computation of the results of a backpressure test on a gas well involves the following steps.

1. Compute rates of flow and pressures at the face of the producing formation from pressure and volume observations made at the wellhead.

2. Determine values of $p_{is}^2 - p_{if}^2$ and $\bar{p}_R^2 - p_{wf}^2$ and rates of flow corresponding to these pressure factors. Then, p_R and \bar{p}_{wf} are calculated at the midpoint of the sandface in wells without tubing. If the well has tubing, they are determined at the entrance to the tubing, provided the entry to the tubing is no more than 100 ft from the midpoint of the sandface.

3. Plot values of q_g and corresponding values of $\bar{p}_R^2 - p_{wf}^2$ and $p_{is}^2 - p_{if}^2$ on logarithmic coordinates.

4. Determine values of the exponent n and the performance coefficient C of the flow equations

$$q_g = C(\bar{p}_R^2 - p_{wf}^2)^n$$

and

$$q_g = C(p_{is}^2 - p_{if}^2)^n.$$

For most routine analyses of backpressure tests, determination of the value of C is not necessary.

5. Determine the CAOF. Computations for rate of flow and pressures at the producing formation are explained in separate sections.

A convenient form for reporting the results of a multipoint test is illustrated in Table 33.4 for the test data taken on Well A and reported in Table 33.3. Table 33.4 shows general well information, a summary of test data, calculation of rates of flow, data for determining compressibility, and the difference of squares of pressures for wellhead and bottomhole conditions. The calculated OFP of $25,000 \times 10^3$ cu ft/D was determined in Fig. 33.3 where the rate of flow is the abscissa and $\bar{p}_R^2 - p_{wf}^2$ (in thousands) is the ordinate on logarithmic coordinates. The data points were connected by a straight line and extrapolated to a value of $\bar{p}_R^2 - p_{wf}^2$, where p_{wf}^2 is zero. In this case, the value is $\bar{p}_R^2 = 230.9$ (thousands). The corresponding rate of flow is $25,000 \times 10^3$ cu ft/D. The AOF of $25,000 \times 10^3$ cu ft/D for Well A is for a 3-hour four-point test. If the test were for a lesser-time four-point test, the resulting AOF would have been more than $25,000 \times 10^3$ cu ft/D.

The exponent n was determined by taking values of q_g and $\bar{p}_R^2 - p_{wf}^2$ from the straight line in Fig. 33.3 and Eq. 7 as follows.

$q_g, 10^3 \text{ cu ft/D}$	$\bar{p}_R^2 - p_{wf}^2 \text{ (thousands)}$
20,000	168
4,000	16.8
$n = \frac{\log 20,000 - \log 4,000}{\log 168 - \log 16.8} = \frac{\log 5.00}{\log 10.0} = \frac{0.699}{1.000}$	

= 0.699.

*This test, used in the 1962 edition of the handbook, was run many years ago. It still stands as a classic multipoint test example today.

TABLE 33.3—FIELD DATA SHEET FOR MULTIPOINT TEST (WELL A)

DATE		WELLHEAD WORKING PRESSURE				METER OR PROVER			REMARKS	
Time	Hrs.	Tbg. Psig	Ceig. Psig	Annulus Psig	Temp. F	Psig	Diff.	Temp. F	Orifice	
Well shut in for 20 days										
4:30 a	-	-	435.3	-	-	-	-	-	-	SIP
2" Prover installed on wellhead										
5:00 a	0	-	435.3	-	-	430.9	-	-	3/4	SIP
5:30	.5	-	418.9	-	-	414.5	-	66	-	Gas Dry
6:00	1.0	-	415.8	-	-	411.4	-	68	-	-
6:30	1.5	-	413.9	-	-	409.2	-	68	-	-
7:00	2.0	-	412.6	-	-	408.2	-	69	-	Gas Dry
7:30	2.5	-	411.4	-	-	407.0	-	69	-	Sp. Gravity 0.719
8:00	3.0	-	410.5	-	-	406.1	-	70	-	1st Point
Plate changed, opened at 8:03										
8:33	.5	-	402.8	-	-	399.4	-	70	7/8	-
9:03	1.0	-	401.1	-	-	392.7	-	71	-	Gas Dry
9:33	1.5	-	399.7	-	-	391.3	-	71	-	-
10:03	2.0	-	398.7	-	-	390.3	-	71	-	Gas Dry
10:33	2.5	-	397.9	-	-	389.5	-	72	-	-
11:03	3.0	-	397.3	-	-	388.9	-	72	-	2nd Point
Plate changed, opened at 11:06										
11:36	.5	-	387.2	-	-	374.1	-	73	1	Gas Damp
12:06 p	1.0	-	385.6	-	-	372.5	-	73	-	-
12:36	1.5	-	384.2	-	-	371.1	-	73	-	-
1:06	2.0	-	383.3	-	-	370.2	-	73	-	Gas Dry
1:36	2.5	-	382.4	-	-	369.3	-	73	-	-
2:06	3.0	-	381.5	-	-	368.4	-	73	-	3rd Point
Plate changed, opened at 2:09										
2:39	.5	-	370.4	-	-	350.2	-	73	1 1/8	-
3:09	1.0	-	368.5	-	-	348.3	-	73	-	Gas Dry
3:39	1.5	-	367.2	-	-	347.0	-	73	-	-
4:09	2.0	-	366.2	-	-	346.0	-	73	-	Gas Dry
4:39	2.5	-	365.2	-	-	345.0	-	73	-	-
5:09	3.0	-	364.3	-	-	344.1	-	73	-	4th Point

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The performance coefficient C was determined from the exponent $n=0.699$, Eq. 5, and one of the corresponding values of q_g and $\bar{p}_R^2 - p_{wf}^2$ as follows.

$$20,000 = C(168)^{0.699}$$

$$C = 20,000/(168)^{0.699}$$

$$\log C = \log 20,000 - 0.699 \log 168$$

$$\log C = 4.3010 - 1.5555$$

$$C = 557.$$

The value of 557 may be checked by extrapolating the straight line on Fig. 33.3 to $\bar{p}_R^2 - p_{wf}^2 = 1$ and reading the corresponding value of q_g . Note that the value of $C=557$ is for q_g in units of 10^3 cu ft/D and for $\bar{p}_R^2 - p_{wf}^2$ in units of thousands.

The backpressure equation for the results of the multipoint test on Well A given in Table 33.4 and illustrated in Fig. 33.3 is

$$q_g = 557(\bar{p}_R^2 - p_{wf}^2)^{0.699}.$$

The wellhead performance of Well A as determined by the test results given in Table 33.4 is illustrated in Fig.

33.4 where q_g and corresponding $p_{is}^2 - p_{if}^2$ values are plotted on logarithmic coordinates. The straight line has been extended to show a wellhead OFP of $22,000 \times 10^3$ cu ft/D. The exponent is 0.672 and C is 627. The backpressure relationship corresponding to Eq. 6 is

$$q_g = 627(p_{is}^2 - p_{if}^2)^{0.672}.$$

This wellhead performance equation for Well A, illustrated in Fig. 33.4, is a measure of the ability of Well A to deliver gas at the wellhead through 5½-in. casing as indicated by the multipoint test given in Table 33.4. The relationship is influenced by the size of the flow string and hydrostatic head of the gas column as well as the productive capacity of the well.

An example of the bottomhole performance as indicated by a multipoint test is given in Fig. 33.2 for an extremely large-capacity well. Well B (Fig. 33.4) had a shut-in pressure \bar{p}_R of 5,169 psia at a depth of 10,658 ft and a wellhead pressure of 4,173 psia. The calculated OFP was $280,000 \times 10^3$ cu ft/D. The corresponding wellhead performance for Well B producing through 2⅞-in.-OD, 6.5-lbm/ft tubing is illustrated in Fig. 33.5 where the data points for the test are plotted as circles.

TABLE 33.4—RESULTS OF MULTIPOINT BACKPRESSURE TEST (WELL A)

COMPANY _____ LEASE _____ WELL NO. A
 ADDRESS _____ DATE 6-17 1947
 DISTRICT _____ FIELD Hugoton RESERVOIR Hugoton
 LOCATION Texe County, Oklahoma
 CASING SIZE 5 1/2" WT. 14# I.D. 5.012 SET AT 2630 PERF. 2465-2620
 TUBING SIZE _____ WT. _____ I.D. _____ SET AT _____ PERF. _____
 PRODUCING SECTION FROM 2465 TO 2620 H. 2542 BOTTOMHOLE TEMPERATURE 90 @ 2540
 ELEVATION _____ DATE OF COMPLETION _____ PRODUCING THROUGH TBG. - CASING x
 F_r 0.001605 BAROMETER 13.2 psi ACRES -

REMARKS: _____

NO.	FLOW DATA			TUBING DATA		CASING DATA		Duration of Flow Hr.
	Prover Line Size X Choke Orifice Size	Press. psig	Diff. h _w	Temp. F	Press. psig	Temp. F	Press. psig	
1	2" 3/4	406.1	-	70	-	-	435.3	66
2	7/8	388.9	-	72	-	-	410.5	70
3	1	368.4	-	73	-	-	397.3	72
4	1 1/8	344.1	-	73	-	-	381.5	73
5							364.3	73

NO.	Coefficient (24-Hour)	$\sqrt{h_w p_i}$	Pressure p _i	Flow Temp. Factor F _t	Gravity Factor F _g	Compress. Factor F _{pv}	Rate of Flow q _g · 10 ³ cu ft/D
1	9.694		419.3	0.9905	1.179	1.038	4928
2	13.33		402.1	0.9887	1.179	1.037	6479
3	17.53		381.6	0.9877	1.179	1.035	8062
4	22.45		357.3	0.9877	1.179	1.032	9640
5							

NO.	P _i	Temp. R	T _r
1	0.65	530	1.46
2	.62	532	1.46
3	.59	533	1.46
4	.55	533	1.46
5			

Gas Liquid Hydrocarbon Ratio _____ Mcf/bbl.
 Gravity of Liquid Hydrocarbons _____ deg.
 Specific Gravity Separator Gas _____
 Specific Gravity Flowing Fluid 0.719
 Critical Pressure 668 - 21 = 647 psia.
 Critical Temperature 398 - 34 = 364 R.
 H₂S _____ % CO₂ 0.1 % N₂ 12.0 %

P_i 448.5 psia P_i² 201.15 × 10³ P_r 480.5 P_r² 230.92 × 10³

NO.	P _{ti}	p _{ti} ²	Δp ²	P _{wf}	P _{wf} ²	Δp ²
1	423.7	179.52	21.63	436.3	208.23	22.69
2	410.5	168.51	32.64	444.0	197.15	33.77
3	394.7	155.79	45.36	429.7	184.64	46.28
4	377.5	142.51	58.64	414.9	172.15	58.77
5						

Potential 25,000 10³ cu ft/D
 n 0.699
 Commission _____
 Company _____
 Others _____

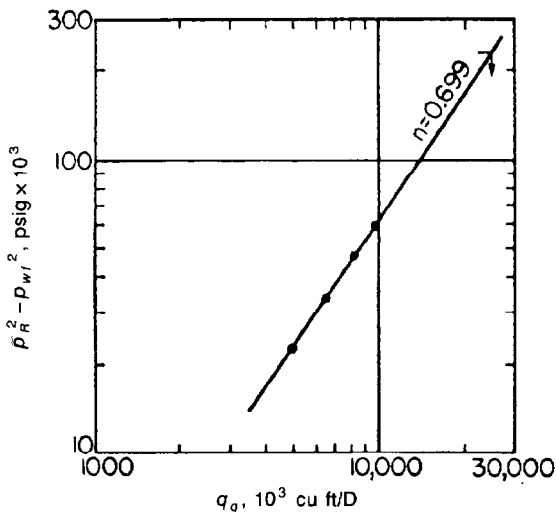


Fig. 33.3—Multipoint test showing bottomhole performance for Well A.

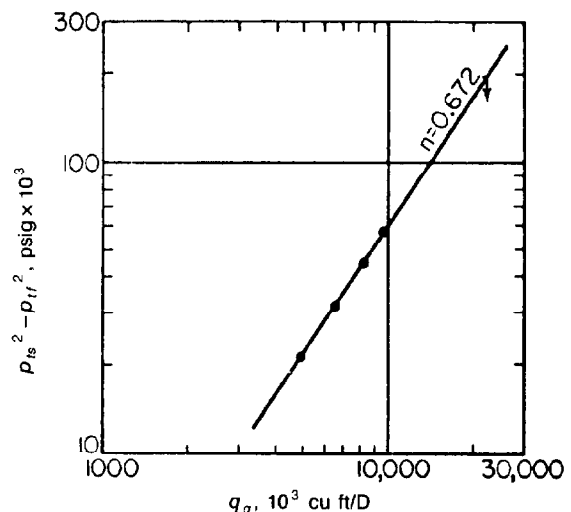


Fig. 33.4—Multipoint test showing wellhead performance for Well A.

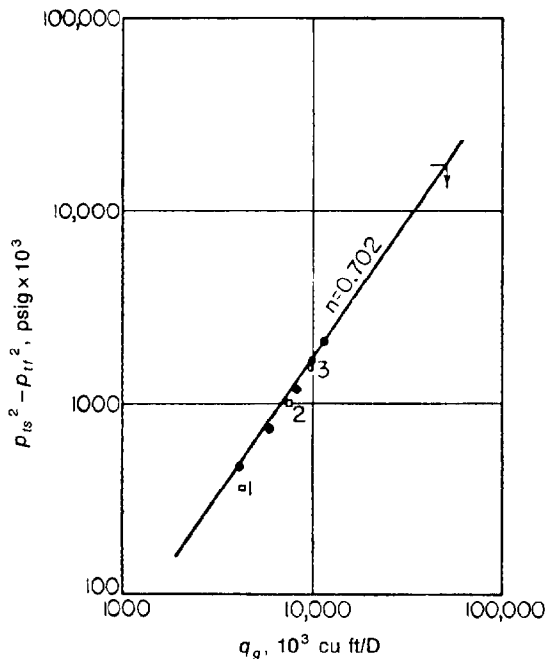


Fig. 33.5—Multipoint test showing wellhead performance for Well B.

Data points represented as squares (Fig. 33.5) are flow tests of several days' duration with Point 1 taken shortly after production started and Point 3 taken over a year later. The position of the data points in Fig. 33.5 indicated that the performance of Well B improved after the well was placed on production, which was probably caused by the removal of drilling fluids from the area around the wellbore.

The wellhead OFP of Well B was $41,000 \times 10^3$ cu ft/D, which was the approximate capacity of the tubing. A different wellhead performance curve would result if the tubing were changed in Well B. The wellhead performance for a different string of tubing can be calculated by starting with the bottomhole performance curve in Fig. 33.2 and calculating the pressure drop caused by friction for the different string of tubing.

Isochronal Test and Example

The isochronal method of backpressure testing as defined by Cullender⁴ considers the performance coefficient C in Eqs. 5 and 6 to be a variable with respect to time until the well stabilizes but a constant with respect to a specific time. Thus the backpressure performance of a well producing from a reservoir with low permeability is a series of parallel curves. Each curve represents the performance of the well at the end of a given time interval. Isochronal performance curves for wells producing from reservoirs with relatively higher permeability are closely spaced. For example, the isochronal curves for various times for Well B (Fig. 33.5) are for all practical purposes one curve, and Well B is said to stabilize rapidly.

The isochronal method of testing permits the determination of the true exponent n of the performance curve for a given gas well. This is accomplished by the

establishment of a simple pressure gradient around a producing well during the test period, which prevents the variation of the performance coefficient with time from obscuring the true value of the exponent. The determination of the relationship between performance coefficient and time permits the estimation of the rate of flow of a given well into a pipeline over long periods of time.

The term "isochronal" was adopted as being descriptive of the method, because only those conditions existing as a result of a single disturbance of constant duration are considered as being related to each other by Eqs. 5 and 6. The expression "single disturbance of constant duration" is defined as those conditions existing around a well as a result of a constant flow rate for a specific period of time from shut-in conditions. Under actual test conditions this requirement is rarely satisfied. However, this condition may be approximated by starting a well on production and allowing the well to produce without further outside or mechanical adjustments in rate of flow. Thus a simple pressure gradient is established around the wellbore as opposed to a complex pressure gradient resulting from a multipoint backpressure test.

The presentation of isochronal test data as a series of parallel curves with a constant exponent n and a constant performance coefficient C for a specific time interval involves certain assumptions. The exponent of the performance curves for a gas well is assumed independent of the drainage area. It is established immediately after the well is opened. The variations of the performance coefficient with respect to time are believed to be independent of the rate of flow and the pressure level under simple gradient conditions.

The procedure employed to obtain the necessary performance data for an isochronal test is to open a well from shut-in conditions and obtain rate-of-flow and pressure data at specific time intervals during the flow period without disturbing the rate of flow. After sufficient data have been obtained, the well is shut in and allowed to return to a shut-in condition comparable with that existing at the time the well was first opened. The well is again opened at a different rate of flow with data being obtained at the same time intervals as before. The procedure may be repeated as many times as necessary to obtain the desired number of data points.

With the exception of starting each rate of flow from shut-in conditions, the procedure for running isochronal tests is the same as that for the multipoint test. The necessity for cleaning the well, calibrating the gas-measuring equipment, and accurately measuring pressures and temperatures remains the same. At least four rates of flow should be taken; the lowest rate should reduce the pressure at the wellhead about 5% and the highest rate of flow should reduce the pressure about 25%.

The results of an isochronal test are computed in the same manner as those for a multipoint test. The data points are plotted on logarithmic coordinates as illustrated in Figs. 33.6 and 33.7. The isochronal curves are drawn so that the points taken at a constant time for the various rates of flow are joined by a straight line. For example, all the points on the line labeled "Time, 3 hr" in Fig. 33.6 represent the performance of Well A after flowing at the various rates of flow for 3 hours from shut-in conditions.

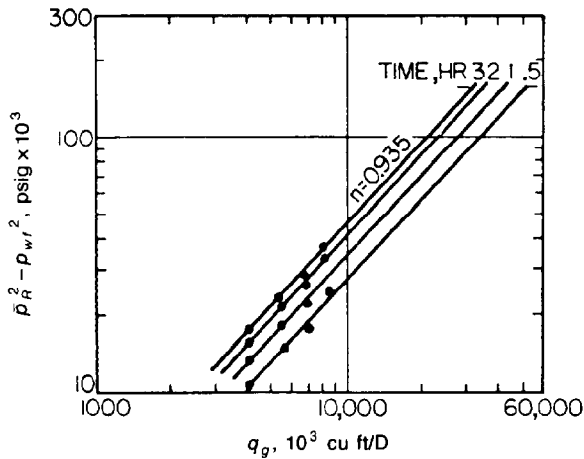


Fig. 33.6—Isochronal test showing bottomhole performance for Well A.

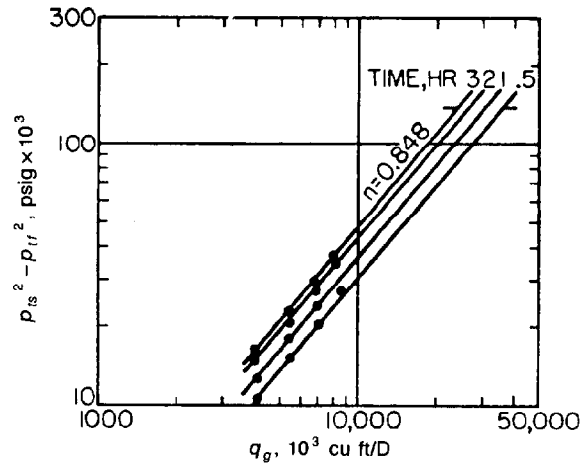


Fig. 33.7—Isochronal test showing wellhead performance for Well A.

The results of isochronal tests can be analyzed in two ways. One way is to use Eqs. 7 and 8 and the properties of the gas to determine the properties of the reservoir and the skin factor. The second way is to use the results as a basis for comparison of well performance at the time of the test with performance as measured previously or to set a base against which future performance is to be compared.

The isochronal type curves shown on Fig. 33.6 can be used to estimate the pressures that would have been observed if the test had been a constant-rate drawdown test. Test periods longer than the 3-hour periods on Fig. 33.6 are much more desirable for this purpose. With this information the $k_g h$ value for the reservoir and the total skin value ($s_t = s + F_{nD} q_g$) are calculated as given in Chap. 35. This results in several values for the total skin, s_t , as a function of the rate of flow, q_g , from which s and F_{nD} can be obtained for use in Eq. 7.⁶ The multipoint test can be analyzed to obtain $k_g h$, s , and F_{nD} as indicated by Ref. 7. A discussion of the performance-comparison method follows.

A copy of actual field data for an isochronal test is given in Table 33.5 for Well A, which is the same well used in the example of a multipoint test.* Four rates of flow of 3 hours' duration were used with each flow starting from shut-in conditions. Shut-in pressures reported varied from 359.6 psig after 48 hours for the first rate of flow to 357.6 psig, which was just previous to the fourth rate of flow. The results of the isochronal test are summarized in Table 33.6. Bottomhole and wellhead performance curves are illustrated on Figs. 33.6 and 33.7, respectively.

The isochronal test on Well A (Fig. 33.6) shows that the calculated OFP for a BHP of 399.1 psia was 51,500, 41,500, 35,000, and 31,500 $\times 10^3$ cu ft/D at the end of 0.5, 1.0, 2.0, and 3.0 hours, respectively. The calculated potential after 3 hours' flow was only 61% of the potential after 0.5 hour of flow. A similar figure for the wellhead performance of Well A is 66% (Fig. 33.7). If Well A were opened into a pipeline with a constant

pressure, the rate of flow at the end of 3 hours would be 66% of the rate of flow at 0.5 hour. Experimental data not given here show that the production at the end of 72 hours has decreased to about 48% of that at 0.5 hour. The figures showing change-of-performance characteristics with time illustrate the need for isochronal test data for estimating the delivery from a particular well into a pipeline. Accurate estimation of pipeline deliveries from wells producing from reservoirs with low permeability is practically impossible without isochronal test data.

Examination of the field notes under the "Remarks" column in Table 33.5 indicates that Well A started to produce water during the flow test taken on Dec. 20, 1951, which was the largest rate of flow. The effect of water production on well performance is illustrated by the irregularities in the corresponding data in Figs. 33.6 and 33.7. Water production and accumulation of water or liquids in the wellbore cause the performance characteristics of a well to deteriorate.

The data represented as squares in Fig. 33.5 are isochronal points taken after Well B has been flowing from 5 to 30 days. Their close agreement with the data from the multipoint test indicates that the performance of Well B does not vary appreciably with time. Well B produces from a reservoir with high permeability and the radius of drainage is established quickly after the well is opened to flow.

Comparison of Multipoint With Isochronal Test

Either the multipoint or the isochronal test is suitable for wells producing from reservoirs with high permeability. The isochronal method of testing is especially suitable for testing wells in low-permeability reservoirs. However, for wells producing from extremely low-permeability reservoirs where the unsteady-state effects last for days or even weeks, economic considerations may limit the testing to only one point of the isochronal type (starting flow from a shut-in condition). Multipoint tests should be limited to reservoirs where the unsteady-state effects are of very short duration. Otherwise the results of the multipoint test are difficult to analyze.

*This test, used in the 1962 edition, was run many years ago. It still stands as a classic isochronal test example today.

TABLE 33.5—FIELD DATA SHEET FOR ISOCHRONAL TEST (WELL A)

DATE		WELLHEAD WORKING PRESSURE				METER OR PROVER				REMARKS
Time	Hrs.	Tub. Psig	Csg. Psig	Annulus Psig	Temp. F	Psig	Diff.	Temp. F	Orifice	
Company _____ Lease _____ Well No. <u>A</u>										
Location <u>Texa County, Oklahoma</u>										
2 "Prover <u>xx</u> "Meter Run <u>xx</u> Taps										
Well shut in for <u>48</u> hours										
<u>12-17-51</u>										
12:20 p	0	-	359.6	-	-	-	-	-	-	SIP
12:50	.5	-	345.1	-	-	341.4	-	67	3/4	
1:20	1.0	-	342.0	-	-	335.4	-	68		Gas Dry
1:50	1.5	-	340.2	-	-	335.6	-	68		
2:20	2.0	-	338.8	-	-	335.2	-	69		Gas Dry
2:50	2.5	-	337.7	-	-	334.2	-	70		
3:20	3.0	-	336.7	-	-	333.2	-	70		Gas Dry
<u>12-18-51</u>										
12:05 p	0	-	358.8	-	-	-	-	-	-	SIP
12:35	.5	-	337.8	-	-	331.4	-	67	7/8	
1:05	1.0	-	333.8	-	-	327.6	-	68		Gas Dump
1:35	1.5	-	331.5	-	-	325.0	-	70		
2:05	2.0	-	329.6	-	-	323.5	-	70		
2:35	2.5	-	328.3	-	-	322.3	-	70		
3:05	3.0	-	327.1	-	-	321.1	-	70		Gas Dump
<u>12-19-51</u>										
11:59 a	0	-	358.8	-	-	-	-	-	-	SIP
12:29 p	.5	-	330.0	-	-	318.7	-	68	1	Gas Dump
12:59	1.0	-	324.8	-	-	313.8	-	69		Gas Dump
1:29	1.5	-	321.6	-	-	310.8	-	70		
1:59	2.0	-	319.4	-	-	308.7	-	71		Gas Dump
2:29	2.5	-	317.7	-	-	307.1	-	72		
2:59	3.0	-	316.3	-	-	305.7	-	72		Gas Dump
<u>12-20-51</u>										
8:22 a	0	-	357.6	-	-	-	-	-	1 1/8	SIP
8:52	.5	-	317.8	-	-	301.3	-	67		Gas Wet
9:22	1.0	-	312.6	-	-	-	-	69		Connection frozen
9:52	1.5	-	309.2	-	-	292.4	-	70		
10:22	2.0	-	306.6	-	-	289.6	-	70		Gas Wet
10:52	2.5	-	304.6	-	-	287.7	-	71		
11:22	3.0	-	302.8	-	-	286.0	-	71		Gas Wet

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TABLE 33.6—RESULTS OF ISOCHRONAL TEST ON WELL A

Date	p_{is} (psia)	Flow Duration (hr)	q_g (Mcf/D)	$\bar{p}_R^2 - p_{wf}^2$	$p_{is}^2 - p_{if}^2$	
Dec. 17, 1951	372.8	0.5	4,159	10.60	10.60	
		1.0	4,120	13.19	12.82	
		2.0	4,078	15.79	15.08	
		3.0	4,047	17.63	16.55	
Dec. 18, 1951	372.0	0.5	5,552	14.85	15.18	
		1.0	5,485	18.10	17.97	
		2.0	5,461	21.58	20.87	
		3.0	5,423	23.56	22.58	
Dec. 19, 1951	372.0	0.5	7,019	17.93	20.59	
		1.0	6,982	22.17	24.14	
		2.0	6,847	26.48	27.76	
		3.0	6,777	28.88	29.81	
Dec. 20, 1951	370.8	0.5	8,599	24.96	27.93	
		1.0				
		2.0	8,153	34.10	35.22	
		3.0	8,048	37.00	37.63	

The results of the 3-hour multipoint test and the 3-hour isochronal test on Well A are shown together in Fig. 33.8 as wellhead performance curves. The exponent (0.672) for the multipoint test is less than the exponent (0.848) of the isochronal test. In general, exponents of multipoint curves run in increasing rate sequence are less than those for isochronal curves for the same well. The first data point on the multipoint test ($q_R = 4,928$ Mcf/D) is on the isochronal curve (Fig. 33.8) because the first rate of flow for the multipoint curve was started from shut-in conditions. Thereafter, the position of each succeeding point of the multipoint test is influenced not only by the rate of flow but also by each preceding point.

The initial points of each multipoint test on wells producing from reservoirs with low permeability represent the formation characteristics, while other points represent complex conditions that are almost impossible to interpret. The characteristic exponent of the isochronal curve still applies to the complex points, with the only difference in performance being in the performance coefficient C. If the exponent of 0.848 is applied to the complex points of the multipoint test (Fig. 33.8), it can be

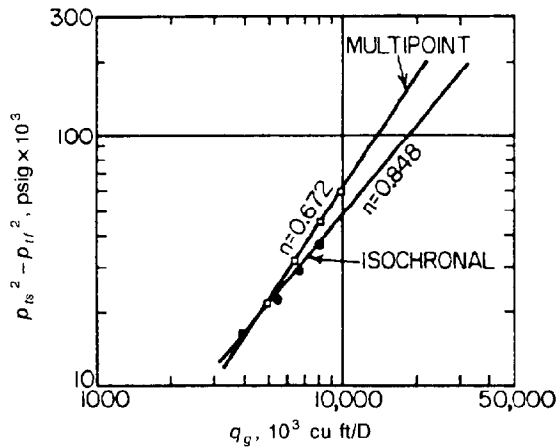


Fig. 33.8—Comparison of multipoint with isochronal test for Well A.

seen that the coefficient obtained in each case can be considered the result of an “effective” time, which has no permanent significance because it is not equal to the elapsed time or to the elapsed time since the last change in flow rate.

An examination of the multipoint and isochronal data presented in Fig. 33.5 for Well B shows that there are certain gas wells that stabilize so rapidly that there is no necessity for obtaining isochronal performance data. As the time required for stabilization increases, the differences between data obtained by the isochronal test and the multipoint test increase.

Gas Measurement

Orifice Meters

The recommended specifications for orifice meters and methods for computing rates of flow are those published by the American Gas Assn.⁹ It should be noted that the basic orifice factors are for a pressure base of 14.73 psia. Multiplying the basic orifice factors in Ref. 9 by 1.0055 changes volumes to a pressure base of 14.65 psia. Basic orifice factors for a pressure base of 14.65 psia have been published in the test manual of the Corporation Commission of the State of Kansas¹⁰ and the Interstate Oil Compact Commission.¹¹

Critical-Flow Provers

The following method for measurement and computation of rates of flow for critical-flow provers is a modification of the method published by Rawlins and Schellhardt.² The equation computing rates of flow from measurements with a critical-flow prover is

$$q_g = p_s F_p F_g F_T F_{pv}, \dots (10)$$

where p_s is static pressure on critical-flow prover, psia. Basic orifice factors, F_p , for 2- and 4-in. critical-flow provers are given in Table 33.7. These factors apply only to plates designed according to USBM specifications.

The adjustment factor (Table 33.8) to correct for an assumed specific gravity of 1.000 to the actual specific gravity of the gas flowing through the prover may be computed by

TABLE 33.7—BASIC ORIFICE FACTORS FOR CRITICAL-FLOW PROVER (USBM plate design) $F_p - Mcf/D$

2-in. Prover		4-in. Prover	
Orifice Diameter (in.)	Factor (F_p)	Orifice Diameter (in.)	Factor (F_p)
1/16	0.06569	1/4	1.074
3/32	0.1446	3/8	2.414
1/8	0.2716	1/2	4.319
3/16	0.6237	5/8	6.729
7/32	0.8608	3/4	9.643
1/4	1.115	7/8	13.11
5/16	1.714	1	17.08
3/8	2.439	1 1/8	21.52
7/16	3.495	1 1/4	26.57
1/2	4.388	1 3/8	31.99
5/8	6.638	1 1/2	38.12
3/4	9.694	1 3/4	52.07
7/8	13.33	2	68.80
1	17.53	2 1/4	88.19
1 1/8	22.45	2 1/2	110.6
1 1/4	28.34	2 3/4	136.9
1 3/8	34.82	3	168.3
1 1/2	43.19		

$$F_g = \sqrt{\frac{1}{\gamma_g}}, \dots (11)$$

where γ_g is specific gravity of the flowing gas, air = 1.000.

Factors to correct for an assumed flowing temperature of 60°F to the actual flowing temperature of the gas at the point of measurement are given in Table 33.9 and may be computed by

$$F_T = \sqrt{\frac{520}{T_f}}, \dots (12)$$

where T_f is actual flowing temperature of the gas, (°F+460).

The supercompressibility factor to correct for the effect of gas compressibility is computed from the compressibility by

$$F_{pv} = \sqrt{\frac{1}{z}}, \dots (13)$$

where z is compressibility of the gas at p_s and T_f or the pressure and temperature at point of measurement.

Methods for estimating gas compressibilities are given in Chap. 20.

Calculation of Subsurface Pressures

Specific Gravity of Flowing Fluid

Calculation of either shut-in or flowing pressures in gas wells requires a knowledge of the specific gravity of the fluid in the wellbore. In the case of a gas-condensate well, the specific gravity of the separator gas and the gravity of the stock-tank liquid are measured, and it is

TABLE 33.8—SPECIFIC-GRAVITY ADJUSTMENT FACTOR

$$F_g = \sqrt{\frac{1}{\gamma_g}}$$

Specific Gravity	0.000	0.001	0.002	0.003	0.004	0.005	0.006	0.007	0.008	0.009
0.550	1.348	1.347	1.346	1.345	1.344	1.342	1.341	1.340	1.339	1.338
0.560	1.336	1.335	1.334	1.333	1.332	1.330	1.329	1.328	1.327	1.326
0.570	1.325	1.323	1.322	1.321	1.320	1.319	1.318	1.316	1.315	1.314
0.580	1.313	1.312	1.311	1.310	1.309	1.307	1.306	1.305	1.304	1.303
0.590	1.302	1.301	1.300	1.299	1.298	1.296	1.295	1.294	1.293	1.292
0.600	1.291	1.290	1.289	1.288	1.287	1.286	1.285	1.284	1.282	1.281
0.610	1.280	1.279	1.278	1.277	1.276	1.275	1.274	1.273	1.272	1.271
0.620	1.270	1.269	1.268	1.267	1.266	1.265	1.264	1.263	1.262	1.261
0.630	1.260	1.259	1.258	1.257	1.256	1.255	1.254	1.253	1.252	1.251
0.640	1.250	1.249	1.248	1.247	1.246	1.245	1.244	1.243	1.242	1.241
0.650	1.240	1.239	1.238	1.237	1.237	1.236	1.235	1.234	1.233	1.232
0.660	1.231	1.230	1.229	1.228	1.227	1.226	1.225	1.224	1.224	1.223
0.670	1.222	1.221	1.220	1.219	1.218	1.217	1.216	1.215	1.214	1.214
0.680	1.213	1.212	1.211	1.210	1.209	1.208	1.207	1.206	1.206	1.205
0.690	1.204	1.203	1.202	1.201	1.200	1.200	1.199	1.198	1.197	1.196
0.700	1.195	1.194	1.194	1.193	1.192	1.191	1.190	1.189	1.188	1.188
0.710	1.187	1.186	1.185	1.184	1.183	1.183	1.182	1.181	1.180	1.179
0.720	1.179	1.178	1.177	1.176	1.175	1.174	1.174	1.173	1.172	1.171
0.730	1.170	1.170	1.169	1.168	1.167	1.166	1.166	1.165	1.164	1.163
0.740	1.162	1.162	1.161	1.160	1.159	1.159	1.158	1.157	1.156	1.155
0.750	1.155	1.154	1.153	1.152	1.152	1.151	1.150	1.149	1.149	1.148
0.760	1.147	1.146	1.146	1.145	1.144	1.143	1.143	1.142	1.141	1.140
0.770	1.140	1.139	1.138	1.137	1.137	1.136	1.135	1.134	1.134	1.133
0.780	1.132	1.132	1.131	1.130	1.129	1.129	1.128	1.127	1.127	1.126
0.790	1.125	1.124	1.124	1.123	1.122	1.122	1.121	1.120	1.119	1.119
0.800	1.118	1.117	1.117	1.116	1.115	1.115	1.114	1.113	1.112	1.112
0.810	1.111	1.110	1.110	1.109	1.108	1.108	1.107	1.106	1.106	1.105
0.820	1.104	1.104	1.103	1.102	1.102	1.101	1.100	1.100	1.099	1.098
0.830	1.098	1.097	1.096	1.096	1.095	1.094	1.094	1.093	1.092	1.092
0.840	1.091	1.090	1.090	1.089	1.089	0.088	1.087	1.087	1.086	1.085
0.850	1.085	1.084	1.083	1.083	1.082	1.081	1.081	1.080	1.080	1.079
0.860	1.078	1.078	1.077	1.076	1.076	1.075	1.075	1.074	1.073	1.073
0.870	1.072	1.072	1.071	1.070	1.070	1.069	1.068	1.068	1.067	1.067
0.880	1.066	1.065	1.065	1.064	1.064	1.063	1.062	1.062	1.061	1.061
0.890	1.060	1.059	1.059	1.058	1.058	1.057	1.056	1.056	1.055	1.055
0.900	1.054	1.054	1.053	1.052	1.052	1.051	1.051	1.050	1.049	1.049
0.910	1.048	1.048	1.047	1.047	1.046	1.045	1.045	1.044	1.044	1.043
0.920	1.043	1.042	1.041	1.041	1.040	1.040	1.039	1.039	1.038	1.038
0.930	1.037	1.036	1.036	1.035	1.035	1.034	1.034	1.033	1.033	1.032
0.940	1.031	1.031	1.030	1.030	1.029	1.029	1.028	1.028	1.027	1.027
0.950	1.026	1.025	1.025	1.024	1.024	1.023	1.023	1.022	1.022	1.021
0.960	1.021	1.020	1.020	1.019	1.019	1.018	1.017	1.017	1.016	1.016
0.970	1.015	1.015	1.014	1.014	1.013	1.013	1.012	1.012	1.011	1.011
0.980	1.010	1.010	1.009	1.009	1.008	1.008	1.007	1.007	1.006	1.006
0.990	1.005	1.005	1.004	1.004	1.003	1.003	1.002	1.002	1.001	1.001

usually necessary to compute the specific gravity of the fluid flowing in the wellbore. The shrinkage of the liquid between the separator and the stock tank is usually unknown and apparently can be neglected. The equation for computing the specific gravity of the flowing fluid, γ_{ff} , is:

$$\gamma_{ff} = \frac{R_{gL}\gamma_g + 4603 \gamma_L}{R_{gL} + V_L} \dots \dots \dots (14a)$$

where

R_{gL} = gas to hydrocarbon liquid ratio, cu ft/bbl,

γ_L = specific gravity of hydrocarbon liquid referred to water, and

V_L = vapor volume equivalent of 1 bbl (60°F) of hydrocarbon liquid, cu ft/bbl.

The specific gravity and the approximate vapor volume of the hydrocarbon liquid can be calculated from the API gravity by

$$\gamma_L = \frac{141.5}{131.5 + \gamma_{API}} \dots \dots \dots (14b)$$

and

TABLE 33.9—FLOWING-TEMPERATURE ADJUSTMENT FACTOR

$$F_T = \sqrt{\frac{520}{T_f}}$$

Observed Temperature (°F)	0	1	2	3	4	5	6	7	8	9
0	1.063	1.062	1.061	1.060	1.059	1.057	1.056	1.055	1.054	1.053
10	1.052	1.051	1.050	1.049	1.047	1.046	1.045	1.044	1.043	1.042
20	1.041	1.040	1.039	1.038	1.037	1.035	1.034	1.033	1.032	1.031
30	1.030	1.029	1.028	1.027	1.026	1.025	1.024	1.023	1.022	1.021
40	1.020	1.019	1.018	1.017	1.016	1.015	1.014	1.013	1.012	1.011
50	1.010	1.009	1.008	1.007	1.006	1.005	1.004	1.003	1.002	1.001
60	1.000	0.9990	0.9981	0.9971	0.9962	0.9952	0.9943	0.9933	0.9924	0.9915
70	0.9905	0.9896	0.9887	0.9877	0.9868	0.9859	0.9850	0.9840	0.9831	0.9822
80	0.9813	0.9804	0.9795	0.9786	0.9777	0.9768	0.9759	0.9750	0.9741	0.9732
90	0.9723	0.9715	0.9706	0.9697	0.9688	0.9680	0.9671	0.9662	0.9653	0.9645
100	0.9636	0.9628	0.9619	0.9610	0.9602	0.9594	0.9585	0.9577	0.9568	0.9560
110	0.9551	0.9543	0.9535	0.9526	0.9518	0.9510	0.9501	0.9493	0.9485	0.9477
120	0.9469	0.9460	0.9452	0.9444	0.9436	0.9428	0.9420	0.9412	0.9404	0.9396
130	0.9388	0.9380	0.9372	0.9364	0.9356	0.9349	0.9341	0.9333	0.9325	0.9317
140	0.9309	0.9302	0.9294	0.9286	0.9279	0.9271	0.9263	0.9256	0.9248	0.9240
150	0.9233	0.9225	0.9217	0.9210	0.9202	0.9195	0.9187	0.9180	0.9173	0.9165
160	0.9158	0.9150	0.9143	0.9135	0.9128	0.9121	0.9112	0.9106	0.9099	0.9092
170	0.9085	0.9077	0.9069	0.9063	0.9055	0.9048	0.9042	0.9035	0.9028	0.9020
180	0.9014	0.9007	0.9000	0.8992	0.8985	0.8979	0.8972	0.8965	0.8958	0.8951
190	0.8944	0.8937	0.8931	0.8923	0.8916	0.8910	0.8903	0.8896	0.8889	0.8882
200	0.8876	0.8870	0.8863	0.8856	0.8849	0.8843	0.8836	0.8830	0.8823	0.8816
210	0.8810	0.8803	0.8797	0.8790	0.8784	0.8777	0.8770	0.8764	0.8758	0.8751
220	0.8745	0.8738	0.8732	0.8725	0.8719	0.8713	0.8706	0.8700	0.8694	0.8687
230	0.8681	0.8675	0.8668	0.8662	0.8656	0.8650	0.8644	0.8637	0.8631	0.8625
240	0.8619	0.8613	0.8606	0.8600	0.8594	0.8588	0.8582	0.8576	0.8570	0.8564

$$V_L = 369 + 5\gamma_{API} + 0.04(\gamma_{API})^2, \dots\dots\dots(14c)$$

where γ_{API} is stock-tank oil gravity, °API. The derivations of Eqs. 14a and 14c were given by Smith.¹²

Equations for Computing Subsurface Pressures

Pressures at the sandface or at the inlet to the tubing in shut-in or flowing gas wells may be measured with BHP gauges or computed from wellhead pressures. However, most subsurface pressures in gas wells are calculated by equations. The most usable and realistic equations available are those of Cullender and Smith,¹³ which have been adopted by the Kansas Corp. Commission, the Interstate Oil Compact Commission, and the New Mexico Conservation Commission, and by the Railroad Commission of Texas for certain fields. The equations were revised¹² recently for use with programmable calculators and small computers.

The revised flow equation for gas wells is

$$\frac{1,000 \gamma_g L}{53.356} = \int_{p_2}^{p_1} \frac{\left(p/Tz - 2.082 \frac{\gamma_g q_g^2}{d_i^4 p} \right) dp}{F^2 + \frac{H}{L} \frac{(p/Tz)^2}{1,000}}, \dots\dots\dots(15)$$

where

L = length of flowstring in well corresponding to H , ft,

H = vertical depth in well, ft, and

q_g = rate of gas flow at 14.65 psia and 60°F, 10⁶ scf/D.

$$F^2 = \frac{2.6665 f q_g^2}{d_i^5} = (F_r q_g)^2 \dots\dots\dots(16a)$$

and

$$\sqrt{\frac{1}{f}} = \frac{4 \log 7.4 r_i}{K}, \dots\dots\dots(16b)$$

where

f = coefficient of friction (friction factor),

r_i = internal radius of pipe, in.,

K = absolute roughness characteristic = 0.0006 in., and

r/K = relative roughness.

Refer to Ref. 12 for the background of Eqs. 15, 16a, and 16b. The second term in the numerator on the right side of Eq. 15 is the kinetic energy term that heretofore has been set at zero because the computations were made manually. Although the kinetic energy term can be neglected without appreciable error in the majority of cases, there is no need to do so when programmable

TABLE 33.10— F_r VALUES FOR VARIOUS FLOW STRING ($K = 0.0006$ in.)

Tubing						Casing					
Nominal Size (in.)	d_o (in.)	(lbm/ft)	d_i (in.)	Minimum N_{Re}	F_r	Nominal Size (in.)	d_o (in.)	(lbm/ft)	d_i (in.)	Minimum N_{Re}	F_r
1	1.315	1.80	1.049	139,000	0.09505						
1¼	1.660	2.40	1.380	189,000	0.04643						
1½	1.990	2.75	1.610	224,000	0.03105						
2	2.375	4.70	1.995	284,000	0.01776						
2½	2.875	6.50	2.441	355,000	0.01050						
3	3.500	9.30	2.992	445,000	0.006180						
3½	4.000	11.00	3.476	525,000	0.004184						
4	4.500	12.70	3.958	605,000	0.002985						
4½	4.750	16.25	4.082	626,000	0.002755						
	4.750	18.00	4.000	612,000	0.002905						
4¾	5.000	18.00	4.276	659,000	0.002442						
	5.000	21.00	4.154	638,000	0.002633						
5¾	5.500	14.00	5.012	784,000	0.001617	7½	8.125	28.00	7.485	1,216,000	0.0005710
	5.500	15.00	4.976	778,000	0.001647		8.125	32.00	7.985	1,199,000	0.0005913
	5.500	15.50	4.950	773,000	0.001670		8.125	35.50	7.285	1,181,000	0.0006126
	5.500	17.00	4.892	764,000	0.001722		8.125	39.50	7.185	1,163,000	0.0006349
	5.500	20.00	4.778	744,000	0.001830	8¼	8.625	17.50	8.249	1,353,000	0.0004438
	5.500	23.00	4.670	726,000	0.001942		8.625	20.00	8.191	1,342,000	0.0004520
							8.625	24.00	8.097	1,326,000	0.0004658
							8.625	28.00	8.003	1,309,000	0.0004801
5%	6.000	15.00	5.524	872,000	0.001256		8.625	32.00	7.907	1,292,000	0.0004953
	6.000	17.00	5.450	860,000	0.001301		8.625	36.00	7.825	1,277,000	0.0005089
	6.000	20.00	5.352	843,000	0.001363		8.625	38.00	7.775	1,268,000	0.0005174
	6.000	23.00	5.240	823,000	0.001440		8.625	43.00	7.651	1,246,000	0.0005394
6¼	6.625	20.00	6.049	964,000	0.0009922	8½	9.000	34.00	8.290	1,360,000	0.0004382
	6.625	22.00	5.989	953,000	0.001018		9.000	38.00	8.196	1,343,000	0.0004513
	6.625	24.00	5.921	941,000	0.001049		9.000	40.00	8.150	1,335,000	0.0004579
	6.625	26.00	5.855	930,000	0.001080		9.000	45.00	8.032	1,314,000	0.0004756
	6.625	28.00	5.791	919,000	0.001111	9	9.625	36.00	8.921	1,473,000	0.0003623
	6.625	31.80	5.675	899,000	0.001171		9.625	40.00	8.835	1,458,000	0.0003715
	6.625	34.00	5.595	885,000	0.001215		9.625	43.50	8.755	1,444,000	0.0003804
6%	7.000	20.00	6.456	1,035,000	0.0008380		9.625	47.00	8.681	1,430,000	0.0003888
	7.000	22.00	6.398	1,025,000	0.0008579		9.625	53.50	8.535	1,404,000	0.0004063
	7.000	23.00	6.366	1,019,000	0.0008691		9.625	58.00	8.435	1,386,000	0.0004189
	7.000	24.00	6.336	1,014,000	0.0008798						
	7.000	26.00	6.276	1,003,000	0.0009018	9¾	10.000	33.00	9.384	1,557,000	0.0003178
	7.000	28.00	6.214	992,000	0.0009253		10.000	55.50	8.908	1,471,000	0.0003637
	7.000	30.00	6.154	982,000	0.0009489		10.000	61.20	8.790	1,450,000	0.0003764
7¼	7.625	29.70	6.875	1,108,000	0.0007119	10	10.750	32.75	10.192	1,704,000	0.0002566
	7.625	33.70	6.765	1,089,000	0.0007423		10.750	35.75	10.136	1,694,000	0.0002602
	7.625	37.70	6.625	1,064,000	0.0007837		10.750	40.00	10.050	1,678,000	0.0002660
							10.750	45.50	9.950	1,660,000	0.0002730
							10.750	48.00	9.902	1,651,000	0.0002765
							10.750	54.00	9.784	1,630,000	0.0002852

calculators or computers are used. Eq. 15 is based on the assumptions that the flow is completely turbulent, the coefficient of friction, f , is a constant, the compressibility of the gas at base pressure and temperature conditions (14.65 psia and 60°F) is 1.000, and only a gas phase is flowing.

Eq. 15 has a subtle but important concept in the value of the quantity H/L at the wellhead, where both H and L are zero. For a vertical wellbore, $H = L$ and

$$\frac{H}{L} = \lim_{H \& L \rightarrow 0} \left(\frac{H}{L} \right) = 1.000.$$

In a deviated wellbore, H is less than L , and for a horizontal pipeline, $H = 0$, and as a result the term for the head of gas drops out of Eq. 15. For a complete guide to the algebraic convention for H and L , refer to Ref. 12.

TABLE 33.11— F_r VALUES FOR VARIOUS ANNULI ($K = 0.001$ in.)

Casing ID (in.)	Tubing OD (in.)							
	1.900	2.375	2.875	3.500	4.000	4.500	4.750	5.000
4.154	0.005082	0.006901	0.01093					
4.276	0.004576	0.006087	0.009268					
4.408	0.004107	0.005356	0.007867					
4.494	0.003838	0.004948	0.007119					
4.580	0.003593	0.004583	0.006473	0.01250				
4.670	0.003361	0.004242	0.005886	0.01086				
4.778	0.003109	0.003880	0.005281	0.009289				
4.892	0.002872	0.003544	0.004738	0.007980				
4.950	0.002761	0.003390	0.004492	0.007419				
4.976	0.002713	0.003324	0.004389	0.007187				
5.012	0.002649	0.003235	0.004251	0.006883	0.01245			
5.140	0.002438	0.002946	0.003809	0.005947	0.01012			
5.240	0.002289	0.002746	0.003509	0.005343	0.008738			
5.352	0.002137	0.002545	0.003213	0.004770	0.007506			
5.450	0.002016	0.002385	0.002983	0.004342	0.006634			
5.524	0.001931	0.002274	0.002825	0.004055	0.006074	0.01098		
5.595	0.001854	0.002175	0.002684	0.003806	0.005601	0.009783		
5.675	0.001773	0.002070	0.002538	0.003552	0.005133	0.008658		
5.791	0.001663	0.001930	0.002346	0.003226	0.004552	0.007351	0.01017	
5.836	0.001623	0.001880	0.002277	0.003111	0.004354	0.006924	0.009455	
5.855	0.001607	0.001859	0.002249	0.003065	0.004274	0.006755	0.009176	
5.921	0.001551	0.001790	0.002155	0.002911	0.004012	0.006215	0.008301	
5.989	0.001497	0.001722	0.002064	0.002764	0.003768	0.005726	0.007528	
6.049	0.001452	0.001665	0.001988	0.002643	0.003570	0.005341	0.006935	0.009582
6.154	0.001376	0.001572	0.001865	0.002450	0.003260	0.004757	0.006057	0.008132
6.214	0.001336	0.001522	0.001799	0.002349	0.003100	0.004466	0.005630	0.007451
6.276	0.001296	0.001472	0.001735	0.002251	0.002947	0.004193	0.005235	0.006837
6.336	0.001259	0.001427	0.001676	0.002161	0.002810	0.003952	0.004892	0.006313
6.366	0.001241	0.001405	0.001647	0.002119	0.002745	0.003839	0.004734	0.006074
6.398	0.001222	0.001382	0.001618	0.002074	0.002678	0.003724	0.004573	0.005835
6.445	0.001195	0.001349	0.001576	0.002012	0.002584	0.003565	0.004352	0.005508
6.456	0.001189	0.001342	0.001566	0.001998	0.002563	0.003529	0.004302	0.005436
6.625	0.001099	0.001234	0.001429	0.001796	0.002266	0.003041	0.003639	0.004486
6.765	0.001032	0.001153	0.001327	0.001651	0.002057	0.002710	0.003201	0.003879
6.875	0.0009830	0.001095	0.001255	0.001549	0.001912	0.002486	0.002910	0.003486
6.969	0.0009439	0.001049	0.001198	0.001469	0.001800	0.002316	0.002692	0.003196
7.185	0.0008619	0.0009524	0.001079	0.001306	0.001577	0.001987	0.002276	0.002655
7.285	0.0008273	0.0009120	0.001030	0.001240	0.001487	0.001857	0.002116	0.002450
7.385	0.0007946	0.0008739	0.0009839	0.001178	0.001405	0.001740	0.001972	0.002268
7.386	0.0007943	0.0008736	0.0009834	0.001177	0.001404	0.001739	0.001970	0.002266

Eq. 15 does not lend itself to mathematical integration without making assumptions regarding T and z , but it may be integrated over definite limits by the trapezoidal rule.

If we let

$$\int_{p_1}^{p_n} \frac{\left[\frac{p}{Tz} - 2.082 \frac{\gamma_g q_g^2}{d_i^4 p} \right] dp}{F^2 + \frac{H}{L} \frac{(p/Tz)^2}{1,000}} = \int_{p_1}^{p_n} I dp = \frac{1,000 \gamma_g L}{53.356}$$

$$= \frac{1}{2} [(p_2 - p_1)(I_2 + I_1) + (p_3 - p_2)(I_3 + I_2) + \dots + (p_n - p_{n-1})(I_n + I_{n-1})], \dots \dots \dots (17)$$

then

$$37.484 \gamma_g L = [(p_2 - p_1)(I_2 + I_1) + (p_3 - p_2)(I_3 + I_2) + \dots + (p_n - p_{n-1})(I_n + I_{n-1})], \dots (18)$$

where $I_1, I_2, I_3 \dots I_n$ is the trapezoidal rule interval corresponding to the respective pressure. If we make the assumptions that the kinetic energy term is zero or that the temperature, T , and the gas compressibility factor, z , are constant, the equations given in Chap. 30 of this handbook can be derived. However, the numerical examples that follow will make use of Eqs. 15 through 18.

The details of computations of a BHFP and a shut-in BHP by Eqs. 16a, 16b, 17, and 18 are illustrated by Example Problem 3 on Page 33-18. To utilize the equations, it is necessary to evaluate the factor F_r for various flow strings. The value may be determined by several correlations; however, the values given in Tables 33.10 and

TABLE 33.12—WORK SHEET FOR CALCULATION OF SUBSURFACE FLOWING PRESSURE BY EQS. 15, 16a, AND 16b

Company		Lease		Well No.		B		Date of Test			
γ_g	0.615	%CO ₂	2.5	%N ₂	—	ρ_{pc}	679	T_{pc}	361	Equations Used	15, 16a, 16b
q_g	11.299	H	10,658	L	10,490	d_i	2.441 in.	Temperature Gradient		5°F/1,000 ft	
					10,658		1.995				
H	L	d_i	ρ_n	T	z	l_n	Δp	$(\Delta p) \times (l_n + l_{n-1})$	$\Sigma(\Delta p) \times (l_n + l_{n-1})$	$37.484 \times \gamma_g L$	Line
0	0	2.441	3,913.0	117	0.8776	104.719	0	—	—	0	1
1,000	1,000	2.441	4,023.1	122	0.8894	104.346	110.1	23,018	23,018	23,053	2
1,000	1,000	2.441	4,023.3	122	0.8894	104.343	110.3	23,059	23,059		3
2,000	2,000	2.441	4,134.0	127	0.9012	103.992	110.7	23,063	46,121	46,105	4
3,000	3,000	2.441	4,245.0	132	0.9129	103.659	111.0	23,049	69,170	69,158	5
4,000	4,000	2.441	4,356.3	137	0.9244	103.337	111.3	23,039	92,209	92,211	6
5,000	5,000	2.441	4,468.0	142	0.9359	103.036	111.7	23,052	115,261	115,263	7
6,000	6,000	2.441	4,580.0	147	0.9472	102.743	112.0	23,047	138,308	138,316	8
7,000	7,000	2.441	4,692.3	152	0.9584	102.464	112.3	23,045	161,352	161,369	9
8,000	8,000	2.441	4,805.0	157	0.9695	102.196	112.7	23,065	184,417	184,421	10
9,000	9,000	2.441	4,917.9	162	0.9805	101.943	112.9	23,047	207,464	207,473	11
10,000	10,000	2.441	5,031.1	167	0.9913	101.693	113.2	23,052	230,516	230,526	12
10,490	10,490	2.441	5,086.7	169.5	0.9966	101.583	55.6	11,302	241,818	241,822	13
10,490	10,490	1.995	5,086.7	169.5	0.9966	76.546	0	—	241,818	241,822	14
10,658	10,658	1.995	5,112.0	170.3	0.9989	76.446	25.3	3,871	245,689	245,695	15

33.11 were calculated by the methods published by Smith.¹²

To compute subsurface pressures where the well is equipped with tubing set without a packer, the preferred practice is to calculate the flowing subsurface pressure from the wellhead pressure measured on the static gas column by means of the static column equations. If the well has a packer, it is necessary to calculate the flowing subsurface pressure by means of the equations for flowing gas columns.

Depths for calculating or measuring subsurface pressures in wells are determined in practice by the equipment installed in the well. Where a well is equipped without tubing or with tubing set without a packer, the proper depth for pressure determinations is the distance to the midpoint of the productive sandface. If the well has tubing set with a packer, the pressures are determined at the entrance to the tubing provided the entry to the tubing is no more than 100 ft from the midpoint of the productive sandface. Otherwise, appropriate corrections would be made to determine the pressure at the midpoint of the sandface.

An explanation of the computational procedures used in Tables 33.12 and 33.13 will be helpful before going into the details of the calculations. The recent advances in computing equipment or, more realistically, the dramatic decrease in the cost of computations have given the average engineer access at least to a handheld programmable calculator or more likely a microcomputer. Therefore, the emphasis in the past has been to simplify equations by making assumptions regarding pressure, temperature, and gas compressibility, but that has not been done here. Now the factor F_r and compressibility factor, z , become subroutines, the results of which are never seen by the user. In this case, Tables 33.10 and 33.11 may seem redundant. The compressibility factors given in Tables 33.12 and 33.13 were calculated by the equation of state published by Hall and Yarborough¹⁴ and Yarborough and Hall.¹⁵ The results of the computations in Tables 33.10 through 33.13 have been rounded,

and the rules for rounding vary from one piece of computing equipment to another. The algorithm used for solving Eqs. 15, 17, and 18 seems to work for all cases, but users may wish to devise their own algorithm.

Example Problem 3—Flowing Well. Details of the method for calculating a flowing subsurface pressure for Well B are given in Table 33.12.

The wellhead flowing pressure for Well B was 3,913 psia at a flow rate of 11.299×10^6 cu ft/D. The annular space between the tubing and casing was packed off and filled with mud so that it is necessary to calculate the flowing subsurface pressure at a depth of 10,658 ft down the flowing column of gas. Gas properties are those given in Table 33.12.

The flow string measures 10,490 ft of 2½-in.-OD, 6.50-lbm/ft tubing with 168 ft of 2¾-in.-OD, 4.70-lbm/ft tubing at bottom of flow string. Also, $H = L$, or the flow string is vertical.

Computation of the required pressure is done in two major steps because of the change in size of the flow string at a depth of 10,490 ft. Computations are given in the following steps.

Step 1. Obtain the ID's from Table 33.10 and enter at top of Table 33.12

$$2\frac{1}{2} \text{ in. OD-ID} = 2.441 \text{ in.}$$

$$2\frac{3}{8} \text{ in. OD-ID} = 1.995 \text{ in.}$$

Step 2. Determine the temperature gradient applicable to the problem. In this example, the flowing temperature of the gas at the wellhead was 117°F, and the subsurface temperature at 10,658 ft was 170°F. The temperature was assumed to be a straight-line relationship between 117°F at $H = 0$ and 170°F at $H = 10,658$ ft for a temperature gradient of 5°F per 1,000 ft.

TABLE 33.13—WORK SHEET FOR CALCULATION OF SUBSURFACE SHUT-IN PRESSURE BY EQS. 15, 16a, AND 16b

Company	Lease			Well No.			B	Date of Test		
γ_g 0.615	%CO ₂ 2.5	%N ₂ —	p_{pc} 679	T_{pc} 361	Equations Used			15, 16a, 16b		
q_g 0	H 10,658	L 10,658	d_i N.A.	Temperature Gradient			5°F/1,000 ft			

H	L	d_i	p_n	T	z	l_n	Δp	$(\Delta p) \times (l_n + l_{n-1})$	$\Sigma(\Delta p) \times (l_n + l_{n-1})$	$37.484 \times \gamma_g L$	Line
0	0	N.A.	4,173.0	117	0.8963	123.931	0	—	—	0	1
1,000	1,000	N.A.	4,266.0	122	0.9071	123.753	93.0	23,036	23,036	23,053	2
1,000	1,000	N.A.	4,266.1	122	0.9071	123.751	93.1	23,059	23,059	23,059	3
2,000	2,000	N.A.	4,359.3	127	0.9177	123.573	93.2	23,051	46,110	46,105	4
3,000	3,000	N.A.	4,452.6	132	0.9282	123.410	93.3	23,043	69,153	69,158	5
4,000	4,000	N.A.	4,546.1	137	0.9385	123.245	93.5	23,062	92,215	92,211	6
5,000	5,000	N.A.	4,639.7	142	0.9486	123.081	93.6	23,056	115,271	115,263	7
6,000	6,000	N.A.	4,733.4	147	0.9586	122.929	93.7	23,051	138,322	138,316	8
7,000	7,000	N.A.	4,827.2	152	0.9685	122.788	93.8	23,048	161,370	161,369	9
8,000	8,000	N.A.	4,921.1	157	0.9782	122.645	93.9	23,046	184,416	184,421	10
9,000	9,000	N.A.	5,015.1	162	0.9877	122.500	94.0	23,044	207,460	207,474	11
10,000	10,000	N.A.	5,109.3	167	0.9971	122.362	94.2	23,066	230,526	230,526	12
10,658	10,658	N.A.	5,171.3	170.3	1.0033	122.286	62.0	15,168	245,694	245,695	13

Step 3. Enter wellhead data on Line 1 where H and L are zero. Calculate I_1 from definition of I in Eq. 17. From Eq. 17, I is:

$$\frac{p}{Tz} - 2.082 \left(\frac{\gamma_g q_g^2}{d_i^4 p} \right) \\ F^2 + \frac{H}{L} \frac{(p/Tz)^2}{1,000}$$

$$\frac{p}{Tz} = (3913)/(577)(0.8776) = 7.72747.$$

Note that z was calculated by methods given in Refs. 14 and 15 (see also Chap. 20).

$$2.082(\gamma_g q_g^2 / d_i^4 p) = \frac{2.082(0.615)(11.299)^2}{(2.441)^4(3913)} \\ = 0.00118.$$

$$[p/Tz - 2.082(\gamma_g q_g^2 / d_i^4 p)] = 7.72629.$$

Using Eqs. 16a and 16b:

$$F^2 = 2.6665(q_g)^2 / \{ (d_i)^5 [4 \log(d_i/K) + 2.27281]^2 \} \\ = 2.6665(11.299)^2 / \{ (2.441)^5 \cdot [4 \log(2.441/0.0006) + 2.27281]^2 \} \\ = 340.425/24,200 = 0.014067,$$

or, from Table 33.10:

$$F^2 = (F, q_g)^2 = (0.01050 \times 11.299)^2 = 0.014075.$$

This value of F^2 will be used later for comparison.

$$(p/Tz)^2 / 1,000 = (7.72747)^2 / 1,000 = 0.059714.$$

At the wellhead, where $H=0$ and $L=0$ for a vertical wellbore $H=L$, then

$$H/L = \lim_{H \& L \rightarrow 0} (H/L) = 1.000.$$

For a deviated wellbore, H is less than L , and for a horizontal pipeline, $H = 0$, and the term for the head of gas drops out of the term for I .

$$F^2 + \frac{H}{L} (p/Tz)^2 / 1,000$$

$$= 0.014067 + (1.000)(0.059714)$$

$$= 0.073781.$$

Then

$$I = (7.72629) / (0.073781) = 104.719.$$

If the F^2 value determined from F , (taken from Table 33.10) is substituted above, I becomes 104.708, which compares well with 104.719.

Step 4. Determine trial Δp (Line 2) for a depth of 1,000 ft by

$$\Delta p_1 = \frac{37.484 \times \gamma_g \times L}{2 I_1} = \frac{37.484(0.615)(1,000)}{2(104.719)} \\ = 110.1 \text{ psi.}$$

Step 5. Complete calculation of first trial I_2 (104.346) on Line 2 where the temperature is 122°F, and the first trial pressure is 3913.0 + 110.1 = 4023.1 psia. At these conditions, the compressibility factor, z , is 0.8894. Estimate the second trial Δp by:

$$\Delta p_2 = \frac{37.484(0.615)(1,000)}{104.719 + 104.346} = 110.3.$$

Step 6. Complete calculation of second trial I_2 (104.343) on Line 3 where the temperature remains at 122°F, and the second trial pressure is $3913.0 + 110.3 = 4023.3$ psia. Under these conditions, the compressibility factor, z , remains at 0.8894. Estimate the third trial Δp by

$$\Delta p_3 = \frac{37.484(0.615)(1,000)}{104.719 + 104.343} = 110.3.$$

Since the third trial Δp is the same to within 0.04 psi, the pressure at a depth of 1,000 ft was determined by trial and error to be $3,913.0 + 110.3 = 4,023.3$ psia. (Note that the third trial was not entered in Table 33.12.)

Step 7. Repeat Steps 4 through 6 to calculate the pressure at a depth of 2,000 ft. Only the final step was given in Table 33.12.

Table 33.13 illustrates the calculation of subsurface shut-in pressures in a gas well by Eqs. 15, 16a, and 16b by the same procedure used in Example 1. The only difference is that for the shut-in well the rate of flow, q_g , is zero and, as a result, the pressure loss caused by friction is zero. Therefore, the inside diameter of the pipe has no effect on the calculations.

Size of Integration Interval

The integration interval was 1,000 ft in Tables 33.12 and 33.13 for a moderately high-pressure well and, for the flowing example (Table 33.12), the rate of 11.299×10^3 cu ft/D gave an effective or average velocity of 14.7 ft/sec near the wellhead. Also, the compressibility factor, z , of the gas at wellhead conditions is in that portion of the z vs. pressure curve where z is very nearly a linear function of pressure. At this low velocity and the nearly linear relationship of z with pressure, an integration interval of 1,000 ft is probably more than enough. Likewise, at low pressures where z is again almost a straight-line function of pressure and at low velocities, the integration interval could be extended to 3,000 ft without undue error. However, even moderate computation facilities eliminate the necessity for expanding the integration interval to more than 1,000 ft.

Application of Backpressure Tests to Producing Problems

Backpressure tests taken properly are useful in predicting delivery rates into a pipeline and in reconditioning studies. For these purposes, either the multipoint or the isochronal test is suitable for wells producing from reservoirs with high permeability such as Well B (Fig. 33.5). The isochronal-type test is necessary for an accurate analysis of producing problems for wells producing from low-permeability reservoirs such as Well A (Fig. 33.7). Although multipoint tests can be used, such analyses are much more difficult.

Well performance at the bottom of the well is a measure of the capacity of the reservoir to deliver gas into the wellbore and is useful in analysis of reservoir problems. A wellhead performance curve is a measure of the capacity of the well to deliver gas into a pipeline and is useful in equipment and reconditioning problems. Usually, an analysis of producing problems can be completed with wellhead backpressure data.

Production Rate

Estimation of the steady production rate of a well into a pipeline operating at a relatively constant pressure requires both test data and a general knowledge of the producing characteristics of the well. For example, an estimate is required of the capacity of Well A (Fig. 33.7) to deliver gas into a pipeline operating at a pressure so that $p_{is}^2 - p_{if}^2$ in thousands equals 20. Starting from shut-in conditions, the delivery rates would be 6,950, 6,000, 5,150, and $4,730 \times 10^3$ cu ft/D. The rate at 72 hours would be $3,340 \times 10^3$ cu ft/D from data given in the text. The steady production rate would be about $2,000$ to $2,400 \times 10^3$ cu ft/D. Although theoretical methods have been published for estimation of stabilized production rates, they would require more data than is available for the well.

Well B (Fig. 33.5) would produce about $4,300 \times 10^3$ cu ft/D into a pipeline when

$$p_{is}^2 - p_{if}^2 = 500$$

as long as the well remained in good condition. Actually, the performance of Well B increased during production and the rate of flow would have increased. The performance of Well B did not deteriorate with time.

Estimation of the sustained production rate of a particular well against fixed pipeline conditions requires a general knowledge of well performance and a definite knowledge of the performance characteristics of the particular well. The accuracy of such estimations is dependent to a large extent on the amount of proper test data available for study.

Causes of Deterioration in Performance

The principal causes of deterioration in gas-well performance are hydrates, liquids, cavings, deposition of salts, equipment leaks, foreign objects, and damage to the producing formation. Any one or a combination of these causes may result in loss of productive capacity and in decreased income. The determination of the cause of deterioration in performance and the recommendation of remedial measures require a history of the performance of the particular well.

The tests illustrated in Fig. 33.8 for Well A give a history of the performance between the date (June 17, 1947) of the multipoint test and the date (Dec. 17, 1951) of the isochronal test. The performance indicated by the first point of the multipoint test ($q_g = 4,928 \times 10^3$ cu ft/D) is the same as that of the isochronal test. Thus it is concluded that the performance of Well A was maintained for about 4½ years. Nothing occurred that harmed the well. Similar conclusions regarding Well B are indicated for the time interval represented by the data on Fig. 33.5.

A regular program of testing gas wells is essential to planning remedial action.

Hydrates

The formation of gas hydrates in the flow string or in the reservoir may cause a well to cease flowing. The author knows of no remedial action to remove hydrates from the producing formation except that of allowing the natural heat of the reservoir to melt the hydrates. The formation of hydrates in the flow string may be prevented by use of

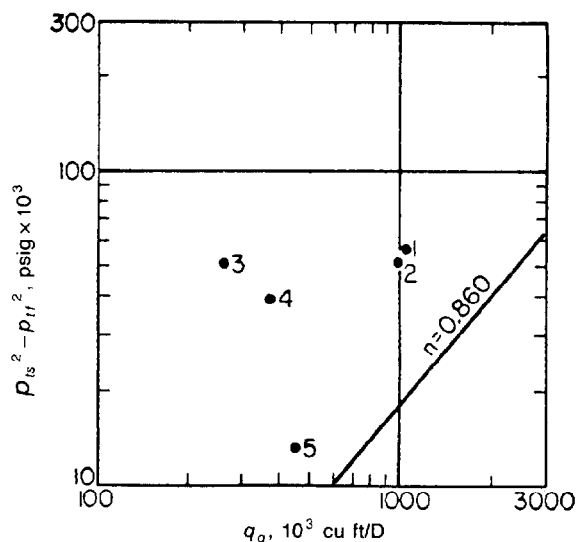


Fig. 33.9—Effect of tubing installation on performance of Well C; Points 1 through 4 are before tubing installation, Point 5 is after.

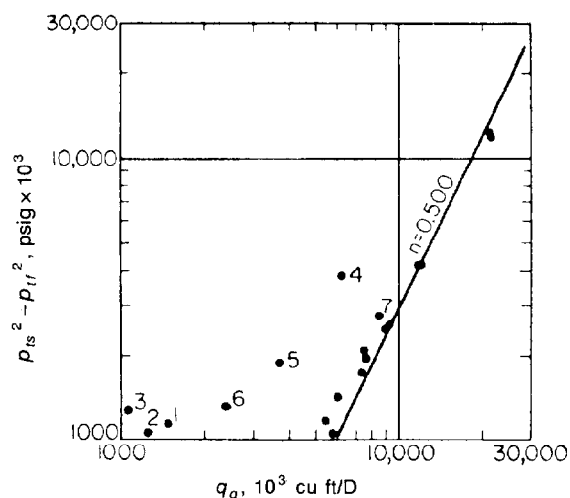


Fig. 33.10—Effect of obstruction in tubing on performance of Well D; Points 1 through 6 are before removal, Point 7 is after.

bottomhole chokes, injection of chemicals such as the alcohols or glycols into the flow string, or by the installation of downhole heating equipment. The accumulation of hydrates in the flow strings may be alleviated to some extent by elimination of obstructions in the flow string, use of proper valve sizes at the surface, elimination of sharp bends in surface lines, and proper placement of chokes in surface lines. Remedial action consists in lowering of hydrate-formation temperatures by chemicals or by maintaining the temperature of the flowing gas above the hydrate-formation temperature. Heating of the flow string in a well is usually accomplished by the circulation of hot oil in the casing around the tubing of the well. However, it must be emphasized that hydrate troubles are very easily confused with liquid troubles in low-temperature wells. A careful study should be made of flowing temperatures in a well before recommendations are made for hydrate prevention.

Liquids

Most performance difficulties in gas wells are caused by the accumulation of liquids in the wellbore. Liquid troubles may be caused by hydrocarbons (condensate and crude oil), salt water, or brines coming into the wellbore from the producing formation, brines from foreign sources through casing leaks, or fresh water. Occasionally, the production of formation water or crude oil may be eliminated by plugback operations. Liquids in wellbores may be removed by tubing strings of proper design, siphon strings (tubing with jet holes or gas-lift valves), and plunger lifts. Periodic flowing of the well at high rates to the pipeline may eliminate liquid troubles.

Remedial action for water troubles requires an identification of the source of the water. This is done by water analyses. If it is decided from analyses that the water is native to the formation, there is a choice between plugback work and water removal by various means. Salt water that is foreign to the producing forma-

tion or fresh water in excessive amounts indicates a casing leak that should be repaired. However, moderate amounts of fresh water usually condense in the flow strings of gas wells. Fresh water that occurs naturally should not be confused with fresh water from a foreign source.

Cavings

Cavings that consist of shale and pieces of the formation are usually most troublesome in openhole completions. The presence of cavings in wells without tubing can be determined easily by comparison of measured depth with drilled depth. Remedial action consists of cleaning out, installation of liners in openhole, and acid washes where the formation is soluble in acid.

Unconsolidated sand is troublesome in many Gulf Coast wells. Sand may damage the performance of a well in addition to causing severe damage to equipment. Remedial action consists of cleaning out, installation of special liners, or consolidation treatment for the formation.

Deposition of Salts

Salts (sodium chloride or other chemical compounds) may be deposited in the flow strings or wellbores of gas wells. Sodium chloride and water-soluble salts often may be removed by water or light acid washes. Occasionally it is necessary to replace the flow string with clean pipe. Heavy crude oil (not a salt) may be removed from the flow string and to a limited extent from the face of the wellbore by washing with kerosene.

Casing and Tubing Leaks

Casing leaks usually permit the migration of gas into another formation, but occasionally in low-pressure areas water may come into the wellbore through leaks. The migration of gas into another formation is wasteful. Casing leaks, depending on their size in relation to well

capacity, cause deterioration in well performance. Positive identification usually can be made with subsurface temperature surveys or special techniques supplied by service companies.

Tubing leaks, where there is no packer, tend to defeat the purpose of the tubing. Liquid removal becomes difficult if the hole in the tubing is large. Small leaks in tubing are usually the result of corrosion. In wells where the annular space is packed off, tubing leaks may allow casing pressures to build up to dangerous levels.

Foreign Objects

Foreign objects such as swab rubbers, stud bolts, or pieces of metal may remain in the flow string of a well after completion. Such objects should be removed from the flow string because they can seriously affect the delivery capacity of a well. The removal of foreign objects from the upstream side of chokes is common.

Examples of Remedial Operations

The effect of water production and the installation of tubing on the performance of Well C in the Texas Hugoton field is illustrated in Fig. 33.9. The curve ($n=0.860$) shows the 3-hour isochronal test results taken immediately after completion. Numbered points are 72-hour isochronal tests taken at yearly intervals, except for Points 4 and 5, which were immediately before and after installation of tubing. Point 1, taken after completion, and Point 2, taken about a year after completion, represent good performance. Points 3 and 4 show poor performance with the result that Well C was producing about 30% of its assigned allowable. A study of Well C indicated that salt water was causing the poor performance. A string of 1 1/4-in. tubing with a 3/32-in. jet hole 100 ft from the bottom of the tubing was installed. The well was then produced continuously through the tubing string. At the time Point 5 was taken, the performance of the well had not only been restored but it had been improved over what it had been originally, which is shown by the relative positions of Points 1, 2, and 5 with respect to the 3-hour isochronal curve. Conclusions regarding Well C are that there was a minor water problem from completion through the time that performance data were taken for Points 1 and 2 (Fig. 33.9). Water movement into the wellbore had seriously damaged the performance of the well at the times Points 3 and 4 were taken. The installation of tubing after Point 4 permitted the removal of water from the well and even allowed the water saturation to be reduced in the formation around the wellbore. The position of Point 5 indicates better 72-hour performance than the well had originally as it is closer to the 3-hour isochronal curve than Points 1 and 2.

An example of the effect of a tubing obstruction on the performance of a well is illustrated in Fig. 33.10 for Well D, where the performance points (indicated by circles with and without numbers) were taken at intervals of a month after start of production. Well D was an extremely high-capacity well as indicated by the position of the original multipoint test. As the numbered points were of long-time-flow duration, it was thought that position of Points 1, 2, and 3 indicated some sort of liquid blockage in the reservoir. However, the tubing appeared to be free of liquids when the well was shut in and pressures were normal. Water-gas and condensate-gas

ratios were normal. Thus it was concluded that liquids were not the source of trouble. After Points 4, 5, and 6 were taken, it was decided to blow the well. Shortly after the well was opened, a swab rubber and several pieces of metal were blown from the well. Afterward, the performance of Well D returned to normal, as indicated by the positions of Point 7 and later performance points that are not numbered on Fig. 33.10.

Space does not permit a complete description of reconditioning procedures. However, it is hoped that this brief outline does illustrate the importance of adequate performance tests in the maintenance of well productivity and planning reconditioning procedures.

Nomenclature

- C = performance coefficient
- d_i = internal diameter, in.
- f = coefficient of friction (friction factor)
- F = term in Eq. 16a
- F_g = specific-gravity adjustment factor
- F_{nD} = non-Darcy flow factor
- F_p = basic orifice factor for critical-flow prover, 10^3 cu ft/D at 14.65 psia, 60°F, specific gravity = 1.000
- F_{pv} = supercompressibility adjustment factor
- F_r = factor defined by Eq. 16a
- F_T = flowing-temperature adjustment factor
- h_m = height (manometer reading), in. mercury
- h_w = height (manometer reading), in. water
- H = vertical depth in a well, ft (in untubed wells H is the vertical depth to the midpoint of the productive formation; in tubed wells H is the vertical depth to the entrance to the tubing)
- I = terms in Eq. 17
- K = absolute roughness characteristic, in.
- L = length of flow string in well corresponding to H , ft
- n = exponent of the backpressure equation or slope of the backpressure curve
- p = pressure, psia
- p_i = impact pressure on a pitot tube, psig
- p_1 = impact pressure on a pitot tube, psia
- p_{pc} = pressure, pseudocritical, psia
- p_R = average pressure in the reservoir at vertical depth H
- p_s = static pressure on critical flow prover, psia
- p_{if} = flowing pressure at wellhead measured on a flowing column of gas, psia
- p_{is} = shut-in pressure at wellhead, psia
- p_{wf} = subsurface (bottomhole) flowing pressure in the wellbore at vertical depth H , psia
- q_g = rate of flow, 10^3 cu ft/D or 10^6 cu ft/D (14.65 psia and 60°F)
- r_i = internal radius of pipe, in.
- R_{gL} = gas to hydrocarbon liquid ratio, cu ft/bbl
- T = temperature, °F+460
- T_f = temperature of flowing gas, °F+460

- T_{pc} = temperature, pseudocritical, °F+460
- T_R = reservoir temperature
- V_L = vapor volume equivalent of 1 bbl (60°F) of hydrocarbon liquid, cu ft/bbl
- z = compressibility factor for gas
- Δ = difference between two values
- γ_g = specific gravity of separator gas or gas being measured, air = 1.000
- γ_{ff} = specific gravity of the flowing fluid, air = 1.000
- γ_L = specific gravity of hydrocarbon liquid referred to water

where

- q_g is in m³/d,
- d_i is in mm,
- p is in kPa,
- V_L is in m/m,
- L is in m,
- T is in K,
- H is in m,
- r_i is in mm, and
- K is in mm.

Key Equations in SI Metric Units

$$q_g = 0.1533 d_i^2 p_1 \dots \dots \dots (4)$$

$$\gamma_{ff} = \frac{R_{gL} \gamma_g + 819.8 \gamma_L}{R_{gL} + V_L} \dots \dots \dots (14a)$$

$$\gamma_L = \frac{141.5}{131.5 + \gamma_{API}} \dots \dots \dots (14b)$$

$$V_L = 65.7 + 0.89 \gamma_{API} + 0.007(\gamma_{API})^2 \dots (14c)$$

$$\frac{1000 \gamma_g L}{31.509} = \int_{p_2}^{p_1} \left(\frac{p}{Tz} - 0.091 \frac{\gamma_g q_g^2}{d_i^4 p} \right) dp \dots \dots (15)$$

$$F^2 + \frac{H}{L} \frac{(p/Tz)^2}{1,000}$$

$$F^2 = \frac{5.3280 f q_g^2}{d_i^5} \dots \dots \dots (16a)$$

$$\sqrt{\frac{1}{f}} = 4 \log \frac{7.4 r_i}{K} \dots \dots \dots (16b)$$

$$63.473 \gamma_g L = [(p_2 - p_1)(I_2 + I_1) + (p_3 - p_2) \cdot (I_3 + I_2) + \dots (p_n - p_{n-1})(I_n + I_{n-1})] \dots \dots \dots (18)$$

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