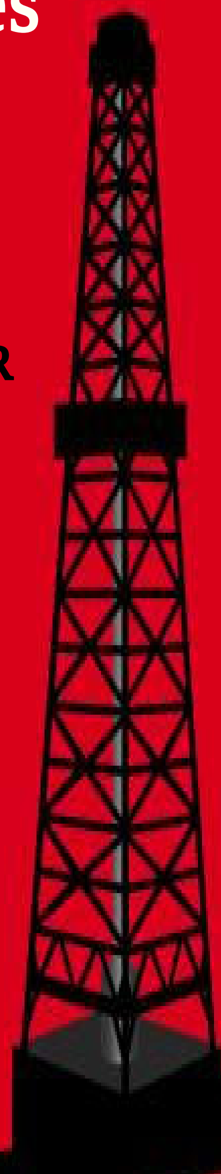
E. L. RAWLINS M. A. SCHELLHARDT

Back-Pressure Data on Natural-Gas Wells and Their Application to Production Practices



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Monograph 7

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By

E. L. RAWLINS AND M. A. SCHELLHARDT

The State of Oklahoma and the Natural-Gas Department of the American Gas Association co-operated in the experimental work on which this report was based. The American Gas Association bore the cost of printing.

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By E. L. Rawlins [2] and M. A. Schellhardt [3]

INTRODUCTION

The capacity of a natural-gas well to produce gas usually has been described in terms of the " open-flow " delivery and the shut-in pressure at the wellhead. Such measurements have been used not only to describe gas-well capacities for company records, but numerous references to them are found in contracts and in the regulations of State commissions.

One of the common methods of determining the " open-flow " capacity of a gas well is to measure the impact pressure with a Pitot tube while the well is flowing " wide open." Such practice, however, wastes gas, and the data obtained do not furnish adequate information relative to the ability of gas wells to deliver gas into pipe-line systems.

How best to conserve natural-gas resources for efficient utilization is one of the main considerations in studying methods of gaging and controlling natural-gas wells. If wells are allowed to blow unrestricted at the wellhead to test their open-flow capacities there necessarily is a loss of a large volume of gas to the atmosphere, especially from wells whose rate of stabilization of pressure-flow conditions is slow, requiring a long " blowing " period to obtain equilibrium. For example, if an average interval of 30 minutes had been required to obtain stabilized flow during the tests conducted on 221 gas wells in the Texas Panhandle fields, which had a combined open-flow capacity of approximately 5,500,000,000 cubic feet of gas per 24 hours, about 115,000,000 cubic feet of gas would have been blown to the air and wasted. If the " blowing " period of the open-flow test made on each of the 40 wells classified as gas wells in the Oklahoma City field, having a total open-flow capacity of 1,200,000,000 cubic feet of gas per 24 hours, had been only 15 minutes, approximately 12,500,000 cubic feet of gas would have been blown to the air during the open-flow tests. These figures of gas wasted are more significant when it is considered that former practice called for periodic open-flow tests throughout the year.

It is evident from the two examples cited that the quantity of gas blown to the air in gaging the open-flow capacity of most gas wells [4] is an appreciable factor, even if the duration of the flow is limited to 15 minutes; however, in some cases this quantity probably is

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[4] Excluding gas wells connected to gathering systems operating under pressures less than that of the atmosphere.

small compared to underground losses or depreciated recoveries that result from such practices. Subjecting gas wells to extreme conditions of flow, such as occur when open-flow tests are made, causes sand and lime formations in the well to cave, aggravates water "coning," and increases the possibility of trapping gas in the underground reservoir with water. Also, under such conditions of flow abrasive material often is carried with the gas from the well at high velocities, damaging well equipment and creating an operating hazard.

The Bureau of Mines has published two reports [5] that describe a method of determining gas-well capacities from data observed when gas deliveries are measured at high back pressures. Interpretations of the pressure data obtained when a well is allowed to flow against high back pressures reveal not only the open-flow capacity of the well but also its ability to deliver gas against different pressures. In contrast, tests of gas wells "wide open" to the atmosphere give the measured rate of open flow only. Because of variation in sand permeabilities, time for flow equilibrium to occur, water conditions, and differences in well equipment the data obtained during such tests cannot be used as a reliable basis for estimating the ability of the well to produce gas under different operating conditions.

There is no definite relationship applicable to all gas wells between the working pressure, expressed in percentage of the shut-in pressure at the wellhead, and the delivery, expressed in percentage of the open flow. For example, two wells, *A* and *B*, each with a shut-in pressure at the wellhead of 1,000 pounds per square inch and an open flow of 25,000,000 cubic feet per 24 hours, and similarly completed and equipped, gave deliveries of 5,000,000 and 8,500,000 cubic feet per 24 hours, respectively, when the working pressures at the wellheads were 950 pounds per square inch.[6] The rate of gas delivery from well *A* was 20 percent of the open-flow delivery at a working pressure equivalent to 95 percent of the shut-in pressure, whereas under similar conditions the delivery from well *B* was 34 percent of the open-flow delivery.

Studies by the authors have indicated the possibility of producing gas at relatively high back pressures with little difficulty from many gas wells subject to liquid accumulation. However, when the back pressures are lowered the changed liquid conditions in the reservoir and well bore apparently caused a different relationship between the pressures and rates of flow. This is illustrated in figure 1, where the rate of delivery from a well at 90 percent of the wellhead shut-in pressure (269 pounds per square inch gage) was approximately 250,000 cubic feet per 24 hours or 44 percent of the actual open flow. If there had been no decrease due to liquid in the gas availability when the well was "wide open," the open flow from the well would have been approximately 700,000 cubic feet per 24 hours. In other words, the delivery at 90 percent of the shut-in pressure would have been 36 percent of the open flow.

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[5] Pierce, H. R. and Rawlins, E. L., The Study of a Fundamental Basis for Controlling and Gaging Natural-Gas Wells, Part 1—Computing the Pressure at the Sand in a Gas Well: Rept. of Investigations 2929, Bureau of Mines, 1929, 14 pp.; Part 2—A Fundamental Relation for Gaging Gas-Well Capacities: Rept. of Investigations 2930, 1929, 21 pp.

[6] Variation in delivery rates from gas wells with different producing characteristics is discussed later in this report.

The size of flow string in a gas well also influences the relationship between the delivery in percentage of open flow and the working pressure in percentage of shut-in pressure. For example, assume that the following data describe a gas well:

Depth	feet	5,000
Diameter of flow string	inches	6⅝
Specific gravity of gas (air=1.00)		0.6
Shut-in pressure at wellhead	pounds per square inch gage	436
Open flow per 24 hours	cubic feet	22,000,000

If the relationship between pressure and rate of delivery[7] for the well is such that the delivery is 3,650,000 cubic feet of gas per

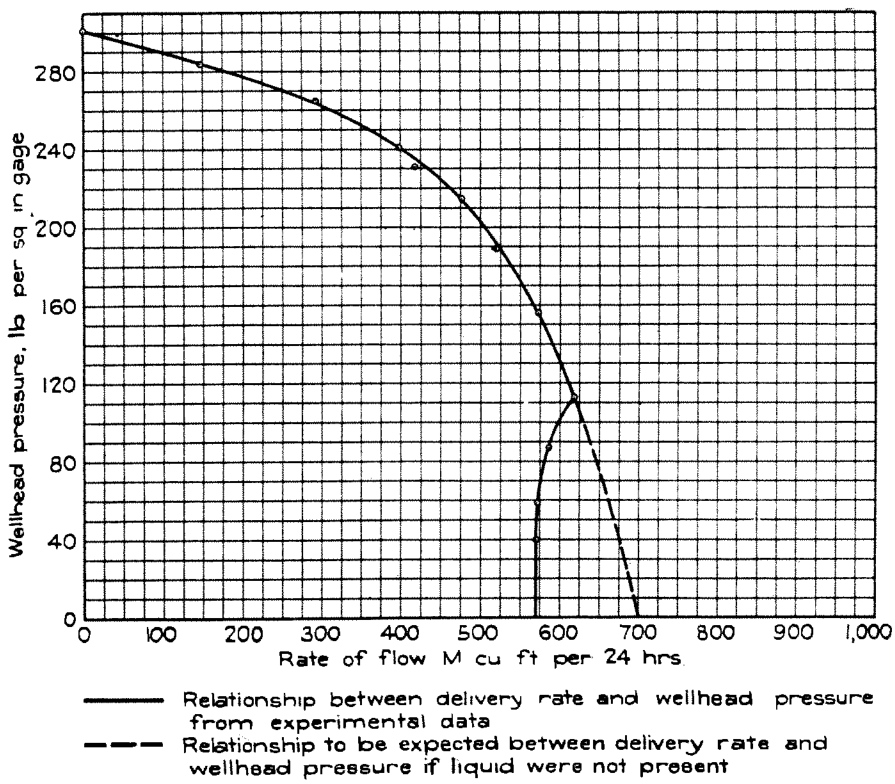

FIGURE 1.—Effect of one kind of liquid condition in a gas well on delivery capacities

24 hours at a wellhead working pressure of 400 pounds per square inch gage, the open flow through 2-inch tubing[8] would be 2,750,000 cubic feet per 24 hours. If the relationship were such that the delivery would be 7,900,000 cubic feet per 24 hours at a working pressure of 400 pounds per square inch gage the open flow through 2-inch tubing would be only 2,830,000 cubic feet of gas per 24 hours. Table 1 illustrates the variation in rates of flow due to variation in the well's characteristics and size of producing string.

Before any attempt is made to correlate delivery in percentage of open flow and working pressure in percentage of shut-in pressure, open flow volumes determined by actual measurement should be based upon the same degree of flow stabilization as the rates of

[7] Discussed later in this report.
[8] Discussed later in this report.

delivery that occur under operating conditions. There is wide variation for different wells in the time required for pressure and flow to become stabilized following a change in delivery rate. Results of actual tests conducted throughout the gas fields of the United States indicate variations ranging from a few minutes to several weeks.

TABLE 1.—*Influence of size of producing string on deliveries from two gas wells with different producing characteristics. (Each well 5,000 feet deep and with shut-in pressure of 436 pounds per square inch gage at wellhead. Gravity of gas = 0.6)*

Well	Size of flow string, inches	Open flow, M cu. ft. per 24 hours	Delivery at wellhead working pressure of 400 lb. per sq. in. gage, M cu. ft. per 24 hours	Open flow delivered at 400 lb. per sq. in. gage, percent
1	6⅝	22,000	3,650	17
1	2	2,750	950	35
2	6⅝	22,000	7,900	36
2	2	2,830	1,040	37

The disadvantages of actual measurement of open flow when a well is producing gas at its maximum capacity can be summarized as follows:

1. There is excessive waste of natural gas.
2. Accurate measurement of gas deliveries often cannot be obtained under open-flow conditions.
3. Data obtained only under open-flow conditions do not indicate the delivery capacity of the well under normal operating conditions and are not a reliable basis for controlling production.
4. Extreme conditions of flow often cause underground wastes, resulting in decreased gas recoveries, increased operating difficulties, and danger to wells, operators, and well equipment.
5. Open-flow tests do not furnish adequate data for studying gas-production problems, such as those resulting from the presence of liquids, sand caving, shooting, clogging of sand face, and unsuccessful completion jobs.

For several years there has been general recognition of the need for a simple, fundamental method of gaging gas-well capacities that would obviate many disadvantages incident to open-flow tests. Since the first report on the subject by Bureau of Mines engineers [9] was published, several plans [10] applicable to particular gas-producing areas have been advocated.

Realizing the need and value of a study of gaging gas-well capacities, the natural-gas industry, through the Natural-Gas Department of the American Gas Association, appointed a committee on Gaging Gas-Well Deliveries to cooperate with Bureau of Mines engineers in obtaining data and information relative to this problem.

[9] Bennett, E. O., and Pierce, H. R., New Methods for Control and Operation of Gas Wells: Proc. Nat. Gas Assoc. America, 1925, pp. 69-86.
[10] Diehl, John C., Natural-Gas Handbook: Metric Metal Works, Erie, Pa., 1927, p. 265. Parsons, C. P., Eliminate Blowing of Gas Wells: Oil and Gas Jour., Dec. 6, 1928, p. 54. Fuelhart, D. E., The Open-Flow Capacity of High-Pressure Gas Wells as Determined by the Pressure-Capacity Curve Method: Oil and Gas Jour., May 9, 1929, p. 129.

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The Committee on Gaging Gas-Well Deliveries of the Natural-Gas Department, American Gas Association, has cooperated in the work. The members of this committee are N. C. McGowen, United Gas Public Service Co., Shreveport, La., chairman; M. A. Abernathy, United Gas Public Service Co., Houston, Tex.; J. W. Bartlett, consulting engineer, Dallas, Tex.; H. S. Bean, National Bureau of Standards, Washington, D. C.; H. R. Dickerson, Arkansas Natural Gas Co., Shreveport, La.; J. R. Hatfield, Indian Territory Illuminating Oil Co., Bartlesville, Okla.; R. W. Hendee, Oklahoma Natural Gas Corporation, Tulsa, Okla.; William Moeller, Jr., Southern California Gas Co., Los Angeles, Calif.; B. Oakland, La-Del Oil Properties, Inc., Monroe, La.; H. C. Otis, Southern States Co., Inc., Shreveport, La.; E. L. Rawlins, U. S. Bureau of Mines, Bartlesville, Okla.; F. P. Shayes, United Gas System, Beeville, Tex.; D. A. Sillers, Lone Star Gas Co., Dallas, Tex.; and Ross M. Stuntz, Cities Service Gas Co., Bartlesville, Okla.

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The regulatory bodies of the various oil- and gas-producing States also were interested in the investigation and wherever possible used their influence to facilitate the progress of the work.

The State of Oklahoma cooperated in the study.

SCOPE OF REPORT

This report presents a more extended discussion of the subject matter in earlier Bureau of Mines publications[11] relating to the same study. It supplements the information they contain with recommended procedure for obtaining data and analyzing results that are more practical and easier to use. In addition, it includes an analysis of the application of back-pressure data to gas-production problems.

[11] Work cited, footnote 5.

FUNDAMENTAL RELATION FOR GAGING GAS-WELL DELIVERIES

Pressures found in gas reservoirs and flow strings of gas wells under different conditions of operation are designated by symbols in figure 2. Common practice in the gas fields is to measure gas pressures at the wellhead; formation pressures and pressures at the sand face then are computed from wellhead data.

When the gas wells in a field are shut in and conditions within the reservoir and flow strings are stabilized no gas flows through the formation or through the "producing string." Under stabilized conditions the pressure in the formation is the pressure at the wellhead plus the pressure due to the weight of the column of gas in the producing string. The pressure at the wellhead under shut-in conditions is denoted by P_c in figure 2. P_f, the shut-in formation pressure, is calculated by adding the pressure due to the weight of the gas column to the observed value of P_c, since under shut-in conditions P_f and P_s (pressure at the face of the producing sand) are the same.

A different set of pressure conditions exists throughout the gas-well system when gas is allowed to flow from the reservoir through the well bore to the wellhead. There is a pressure drop in the formation as the gas flows to the well bore and a pressure drop in the producing string as the gas flows from the sand face in the well bore to the wellhead. The volume of gas produced from the reservoir during the period of a back-pressure test compared with the total volume of gas in the reservoir is negligible, and the formation pressure remains practically constant. Therefore, as shown in figure 2, the pressure drop through the formation is denoted by the difference between P_f and P_s. The pressure at the wellhead under flowing conditions is denoted by P_w. For any given condition of a well and its fittings, pressures and flow throughout the system must be stabilized before the delivery rate becomes constant. This stabilization depends upon the factors influencing the flow through the producing string and through the sand. For example, a higher back pressure, P_w, would have to be maintained at the wellhead to restrict the flow to a given rate, or to hold a given back pressure, P_s, at the sand face, if a well were completed with 8¼-inch casing than if it were completed with 6⅝-inch casing, provided other conditions were the same.

Studies have shown that for normal gas wells there is a consistent relationship between rates of delivery of gas and corresponding pressures when the pressures in the sand are used as the basis of interpretation. Results of tests throughout the United States show that when the rates of delivery are plotted on logarithmic paper against $(P_f^2-P_s^2)$—the respective differences of the squares of the formation pressure P_f and the pressure at the sand face P_s—the relationship is represented by a straight line, which may be expressed mathematically by the formula

$$Q=C(P_f^2-P_s^2)^n$$

where Q=rate of flow, M cubic feet per 24 hours,
C=coefficient,
P_f="shut-in" formation pressure, pounds per square inch absolute,
P_s=back pressure at the sand face in the well bore, pounds per square inch absolute,
n=exponent, corresponding to the slope of the straight-line relationship between Q and $(P_f^2-P_s^2)$ plotted on logarithmic paper.

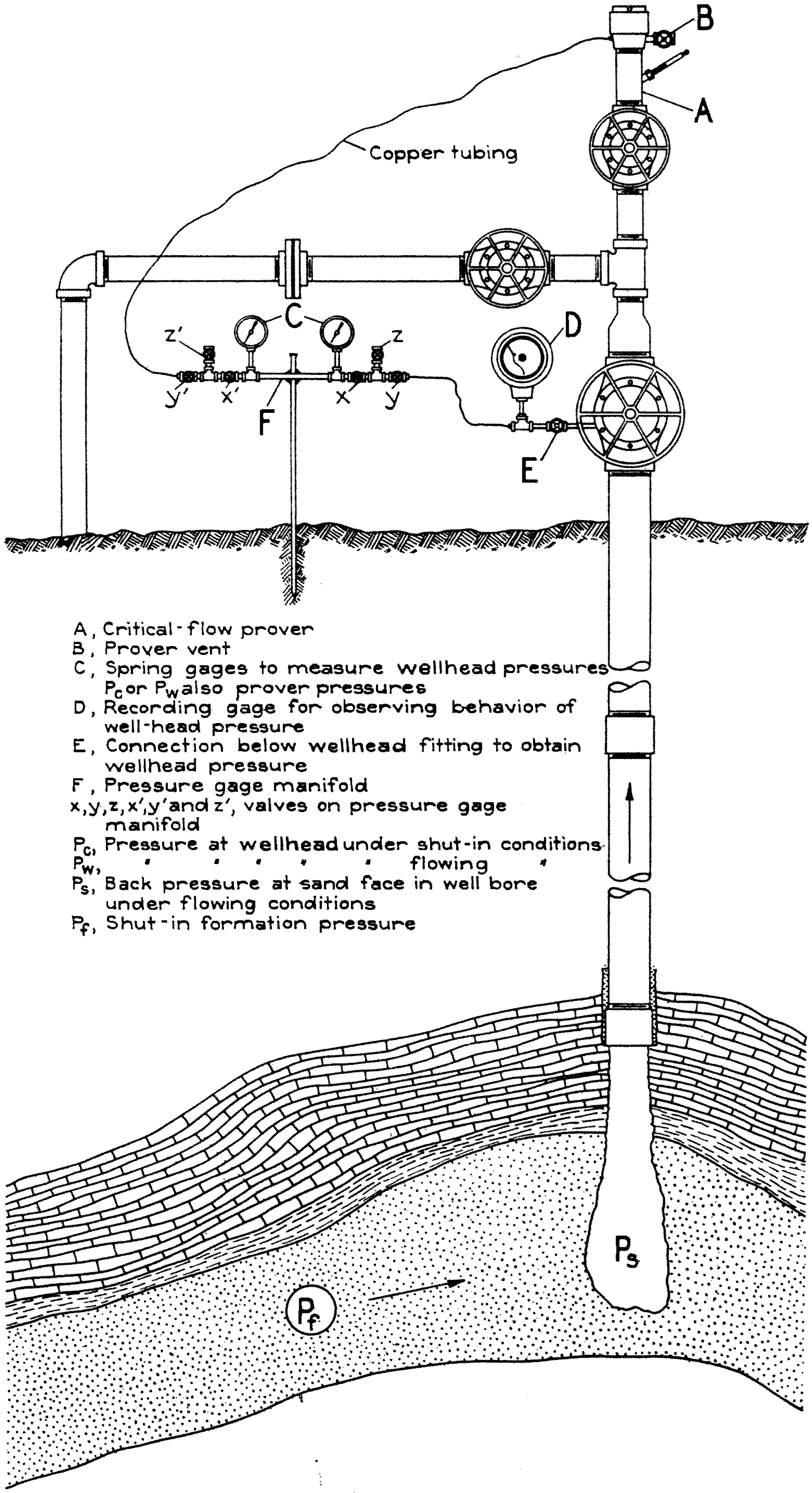


FIGURE 2.—Pressures in a gas-well system under different conditions of operation, and back-pressure test apparatus

Most of the interpretation necessary for applying data obtained from back-pressure tests to gas-production problems can be made from simple calculations based directly on the plotted relationship between the rate of delivery and the difference of the squares of the formation and sand pressures, and it is not necessary to use the formula.

METHODS OF CONDUCTING BACK-PRESSURE TESTS ON NATURAL-GAS WELLS

For all practical purposes data required for the interpretation of back-pressure tests on average gas wells can be observed at the wellheads, although the final interpretation of gas deliveries and the capability of wells to supply gas at different back pressures is based upon conditions in the gas reservoirs. The back-pressure test is comparatively easy to make, and with careful planning there is no need for any considerable interruption in routine field operations while back-pressure data are being obtained. The well to be tested is first shut in at the wellhead, and after the pressures in the well and reservoir sand become stabilized an observation is made of the "shut-in" wellhead pressure. The well then is allowed to produce gas at a high back pressure, and after flow conditions become stabilized observations are made of the pressure at the wellhead and the factors needed to compute the rate of delivery at this working pressure. The back pressure at the wellhead then is lowered, and another set of observations is made of the wellhead pressure and the factors needed to compute the rate of delivery. The process is repeated at several different back pressures until a representative number of working pressures at the wellhead and data needed for computing the corresponding rates of deliveries are obtained. Figure 2 shows the test apparatus connected to a typical set of wellhead connections.

The shut-in wellhead pressure obtained during a back-pressure test, plus the pressure due to the weight of the column of gas, is the stabilized pressure in the reservoir within the control of the well under the operating conditions of the field and depends upon the flowing condition before the back-pressure test and the flowing condition in other wells in the common reservoir. The shut-in pressure of an individual well (corrected to reservoir conditions by adding the pressure due to the weight of the column of gas) is equivalent to the shut-in pressure of the reservoir only when no withdrawal of gas is being made from the reservoir through other wells. If wells producing from a common reservoir are operated intermittently or at varying rates of delivery the limits of the control areas and the shut-in pressures may be subject to different evaluations. Since one of the principal reasons for conducting back-pressure tests is to determine the amount of gas available from a reservoir for market requirements it is best to determine shut-in pressures and obtain back-pressure data on the respective wells of a group supplied from the common reservoir under conditions of normal withdrawal. For estimating gas reserves, however, shut-in pressure data should be based upon the stabilized pressure in the reservoir under closed-in conditions.

In addition to the pressure and measurement data it is necessary to know the specific gravity of the gas, the depth and thickness of the producing stratum, the diameter of flow string through which the gas is produced, and other general information about the well which will be helpful in interpreting the data from the back-pressure

TABLE 2.—*Back-pressure test of gas well*

Date.............................., 193..

Owner ....

Well.................................. S........... T........... R...........

.... Co.................

Sand............Casing at.......... ....Tubing at......................

Specific gravity of gas..............Meter no.............Connections.............

Disk size...............1-hour coefficient...............Pressure base...............

TEST DATA

	Wellhead working pressure on flow string	Wellhead pressure on static string	Differential pressure on meter, in. of water	Static pressure on meter, lb. per sq. in. gage
1			xxxxx	xxxxx
2				
3				
4				
5				
6				
7				
8				

Remarks

Show location of well and acreage under lease.

test. A form used by one company in the Mid-Continent area to record the data obtained from a back-pressure test of a gas well is shown in table 2.

Careful observation of the gas vented to the atmosphere or, if gas is delivered to a pipe-line system, inspection of the drip on the well connection for evidence of entrained substances, observation of the behavior of wellhead pressures following flow adjustment, comparison of shut-in pressures observed before and after a back-pressure test, and comparison of results obtained by changing the sequence of pressure-flow values during a back-pressure test give essential information for proper interpretation of back-pressure data.

SPECIFIC GRAVITY OF GAS

The specific gravity of a gas can be determined with a gravity balance, and it is now common practice in most gas-producing areas to determine periodically the specific gravity of natural gases from individual wells. If data on the specific gravity are available, usually an additional test of the density of the gas at the time of the back-pressure test is unnecessary.

The specific gravity of the gas from a well often varies under different conditions of pressure, temperature, and flow when the reservoir within the control area of the well contains an appreciable proportion of the less-volatile hydrocarbon fractions. However, small variation in specific gravity of the gas has only a negligible effect on interpretation of the results of a back-pressure test.

DEPTH OF WELL

It will be shown later in this report that calculations of back-pressure data are based upon values of the factor GL, where G is the specific gravity of the gas and L the average length of the gas column in the well bore. L for wells producing from a uniformly productive or a relatively thin pay stratum usually is considered to be the distance between the control valve at the wellhead and a point midway between the top and bottom of the producing sand. For wells producing from two or more closely-spaced sands in the same producing horizon, or wells producing gas from a thick stratum that is not uniformly productive, the value of L can be ascertained approximately by averaging the distances between the control valve at the wellhead and points midway between the top and bottom of each producing sand, as indicated by drilling records. If the productive strata are in different producing horizons and are an appreciable distance apart vertically calculation of an average value of L is subject to error, and its proper value depends mainly upon actual data and conditions applicable to the well or wells being studied.

PRESSURES

The degree of accuracy of the wellhead pressure determinations is a most important factor in a back-pressure test. Errors in wellhead pressures are reflected directly in the calculated values of pressures in the reservoir, which are used as the basis for determining the capacity of a well to deliver gas at different back pressures. For instance, a small error in one of the pressures in the factor $P_f^2 - P_s^2$ is reflected as a large percentage error in the difference of the squares of the two pressures. The effect of errors in pressure measurement on the interpretation of data from back-pressure tests of gas wells is discussed in detail in appendix 7.

PRESSURE GAGES

Pressures may be measured with a dead-weight gage[12] or a spring gage. The accuracy obtained with dead-weight gages makes their use advantageous, especially when small differences between the shut-in formation pressure and the working pressures at different rates of flow are involved. A small portable-type dead-weight gage has been developed which is particularly adaptable to routine field testing.

Satisfactory measurements of wellhead pressures can be obtained with spring gages if necessary precautions in their use are observed. There should be no appreciable lost motion in the mechanism of a spring gage used for this work; and a satisfactory spring gage, when checked against a dead-weight gage tester, should show a negligible variation in observed pressures during consecutive tests.

The experience of the authors in testing gas wells in different gas-producing areas of the United States has indicated that satisfactory results can be obtained with spring gages when they are checked daily against a dead-weight gage tester; if the gages are used only occasionally they should be tested before and after using. It is more practicable usually to take account of incorrect readings of spring gages, as obtained by comparison with dead-weight gage testers, by tabulating the error than by resetting the indicating hand on the gage dial, because the amount of error is not always the same over different ranges of pressures.

Spring gages should be calibrated under temperature conditions similar to those likely to occur during the back-pressure tests. Furthermore, the gages should be protected from the rays of the sun while they are being calibrated and when used on a well for back-pressure determinations. The magnitude of the error in spring-gage readings for one set of observations is shown by the following data.

Four spring gages (working range, 0 to 500 pounds per square inch), each made by a different manufacturer, were checked against a dead-weight gage tester at pressures of 200 and 400 pounds per square inch gage in a room where the average temperature was 92° F. The gages then were placed outside the room and allowed to remain unprotected from the rays of the sun for approximately 1 hour. The gages then were returned to the room and rechecked against the dead-weight gage tester at approximately the same temperature (92° F.).

Differences between true or dead-weight pressures and the pressures indicated by the spring gages (table 3) are comparatively small; but, as mentioned previously, pressure determinations made during back-pressure tests of gas wells should be measured as closely as practicable. Pressures can be measured with properly designed spring gages having a range of 0 to 1,000 pounds per square inch with errors not larger than 2 pounds per square inch, and such gages having a range of 0 to 500 pounds per square inch will give an error of not more than 1 pound per square inch if precautions are taken in using them and they are calibrated at frequent intervals against dead-weight gage testers.

[12] Rawlins, E. L. and Wosk, L. D., Leakage from High-Pressure Natural-Gas Transmission Lines: Bull. 265, Bureau of Mines, 1928, p. 8.

The gages selected for back-pressure tests should have a maximum capacity somewhat greater than the pressures to be gaged; and, in general, the maximum capacity of a gage should not exceed twice the value of the shut-in pressure of the well. Preferably the maximum capacity of the gage should be less than twice the shut-in pressure.

Calibrations of spring gages against dead-weight gage testers before and after back-pressure tests often show changes in the condition of the gages. Such changes usually can be detected by comparing observations from two or more gages connected to the same pressure tap. Figure 2 illustrates two spring gages *C*, connected to the same pressure tap for measuring the static pressure on the critical-flow prover. As connected, these two spring gages and the recording gage *D* also may be used to measure the well-head pressure.

When gas is being produced from a well the vibrations set up in the gas line downstream from the well are magnified by the hands of rigidly connected spring gages, and it is difficult to make accurate pressure readings. The effect of the vibrations ordinarily is eliminated by the use of copper tubing for gage connections, as shown in figure 2. In testing some wells it is necessary to attach the gages to supports that are not in contact with any well fittings to reduce the vibration of the gage hands.

TABLE 3.—*Effect of temperature variation on accuracy of spring gages*

Gage	Comparison of dead-weight gage tester and spring-gage readings			
	Before exposure of spring gages to sun		After exposure of spring gages to sun	
	Dead-weight gage-tester reading	Spring-gage reading	Dead-weight gage-tester reading	Spring-gage reading
1	200	204	200	205
	400	402	400	404
2	200	200	200	201
	400	403	400	405
3	200	194	200	195
	400	396	400	399
4	200	201	200	202
	400	398	400	400

MEASUREMENT OF DELIVERY RATES

The gas produced during back-pressure tests on natural-gas wells usually can be measured with orifice meters or critical-flow provers.[13] Non-critical-flow provers can be used in special cases of low pressures and small rates of delivery.

Often orifice meters or other equipment for measuring the flow of gas from individual wells are provided in the gathering system, making it practicable to deliver the gas into a pipeline and measure it there during the period of the back-pressure test. This procedure makes it possible to reduce the waste of gas while testing the delivery capacities of wells, as compared with methods that necessitate venting the gas to the air.

[13] The design and use of critical-flow provers are discussed in detail in appendix 2.

At some wells it is not practicable to deliver the gas into the pipe-line system while a back-pressure test is being made. The relation of the well pressure to the normal line pressure, or the relation of the capacity of the well to the capacity of the gathering system, may be such that the operating pressure on the well cannot be lowered enough to obtain the desired range of back-pressure data. It then is necessary to vent part of the gas to the atmosphere. The gas vented can be measured with a critical-flow prover, or by any equally reliable means.

MEASUREMENT OF DELIVERY RATES WITH ORIFICE METER

The gas produced from wells when operating usually is measured with an orifice meter. If it is possible to obtain the desired range of flows the orifice meter can be used in a back-pressure test. The two most common examples of conditions where the rates of delivery are measured with an orifice meter are under conditions of constant pressure on the meter and controlled pressure on the meter.

If the pipe-line pressure is high compared to the safe working pressure of the meter the range of delivery rates that can be measured through any one size of orifice is limited by the range of differential pressures. Usually best results have been obtained when gas wells are gaged by limiting actual observations to values between 5 and 45 inches of water where the maximum range of the differential pressures on the meter is 0 to 50 inches of water, and 10 to 90 inches of water where the maximum range is 0 to 100 inches. Different sizes of orifices can be used to obtain the desired range of delivery rates.

If the pipe-line pressure is lower than the safe working pressure of the meter and the back pressures at the wellhead that will allow gas to be produced at the desired rates of flow, and if the capacities of gathering and pipe-line systems are large enough to allow the desired variation in flow rates, back-pressure tests with a more suitable range of pressures can be obtained, using only one size of orifice, than is possible with a high constant line pressure. The factors that need to be considered in measuring rates of delivery for a back-pressure test under conditions of constant or controlled pressure on an orifice meter are discussed in detail in appendix 1.

MEASUREMENT OF DELIVERY RATES WITH CRITICAL-FLOW PROVER

Often it is impracticable to measure the gas flow from the well into the gathering system because the desired range of pressure and flow conditions for a back-pressure test cannot be obtained. During the progress of the field investigative work upon which this report is based it has been the practice to measure the gas that could not be delivered into the gathering system with a critical-flow prover, and it is believed that this method of measurement can be used for routine testing purposes. The principal disadvantage of using the critical-flow prover is that the gas passing through the prover is vented to the atmosphere, and as a result some gas is wasted. However, the flows during a back-pressure test occur at relatively high back pressures, and the rates of delivery are low compared with those when the well is wide open to the atmosphere. Also, the high back pressures eliminate many of the underground gas losses and reduce water hazards considerably compared with conditions of open flow.

The design and use of critical-flow provers are discussed in detail in appendix 2. Generally only two sizes of provers, one with an internal diameter of 2 inches and the other with an internal diameter of 4 inches,[14] were used by the authors to obtain back-pressure data on gas wells in the principal gas-producing areas of the United States. Although the range of capacity of critical-flow provers is limited by existing pressure conditions and by the range in sizes of orifices provided for the provers the capacity of the 4-inch prover was amply large for the measurement of all rates of flow desired for the back-pressure tests, and in most tests the pressure and flow conditions were such that the 2-inch prover could be used. Where possible it is particularly advantageous to use the 2-inch prover because it weighs less and can be connected to the wellhead more easily than a 4-inch prover.

USE OF ORIFICE METERS AND CRITICAL-FLOW PROVERS IN SAME BACK-PRESSURE TESTS ON GAS WELLS

During the progress of the field work connected with the study of gaging gas-well deliveries back-pressure tests were made on many wells where only limited ranges of pressure and flow could be obtained while the gas was being measured into the gathering system. Since it was desirable to reduce to a minimum the quantity of gas blown to the atmosphere during all tests and at the same time to obtain back-pressure data throughout comprehensive ranges of pressure and flow, observations were made of the rates of gas delivery at high back pressures while the gas was being delivered into the gathering system (as far as conditions would permit) and at lower back pressures by venting the gas to the atmosphere. In some instances the discharge valve downstream from the meter was closed and the gas was vented to the atmosphere through an opening in the discharge line between the meter and the closed gate valve. The measurements of rates of delivery were made with either an orifice meter or a critical-flow prover, depending upon the relationship between wellhead and pipe-line pressures and the capacity of the orifice meter. In other tests, the flows were vented to the atmosphere through openings in the discharge line from the well between the wellhead and the orifice meter and the deliveries measured with a critical-flow prover. It also is practicable to supplement data obtained on the gathering system with a limited number of observations of pressures and delivery rates made at the wellhead, the critical-flow prover being connected directly to the wellhead fittings, instead of venting gas to the atmosphere through an opening in the orifice-meter setting.

Results of back-pressure tests on two natural-gas wells are shown in figure 3, in which the rate of flow Q is plotted on logarithmic paper against the pressure factor $P_f^2 - P_s^2$. In case I an orifice meter was used to measure the gas delivery rates at three different back

[14] See figs. 35 and 36, appendix 2, of this report.

pressures. The range of flow rates was 175,000 to 550,000 cubic feet of gas per 24 hours. The critical-flow prover then was used to measure the delivery rates of 1,140,000 and 1,830,000 cubic feet of gas per 24 hours at lower back pressures. In case II the critical-flow prover was used to measure four different rates of flow, and an orifice meter was used for two rates within the same range. The consistency of the results is indicated by the plotted data.

MEASUREMENT OF DELIVERY RATES WITH CHOKE NIPPLES

Choke nipples can be used to measure rates of delivery of gas during back-pressure tests where the flows of gas have to be

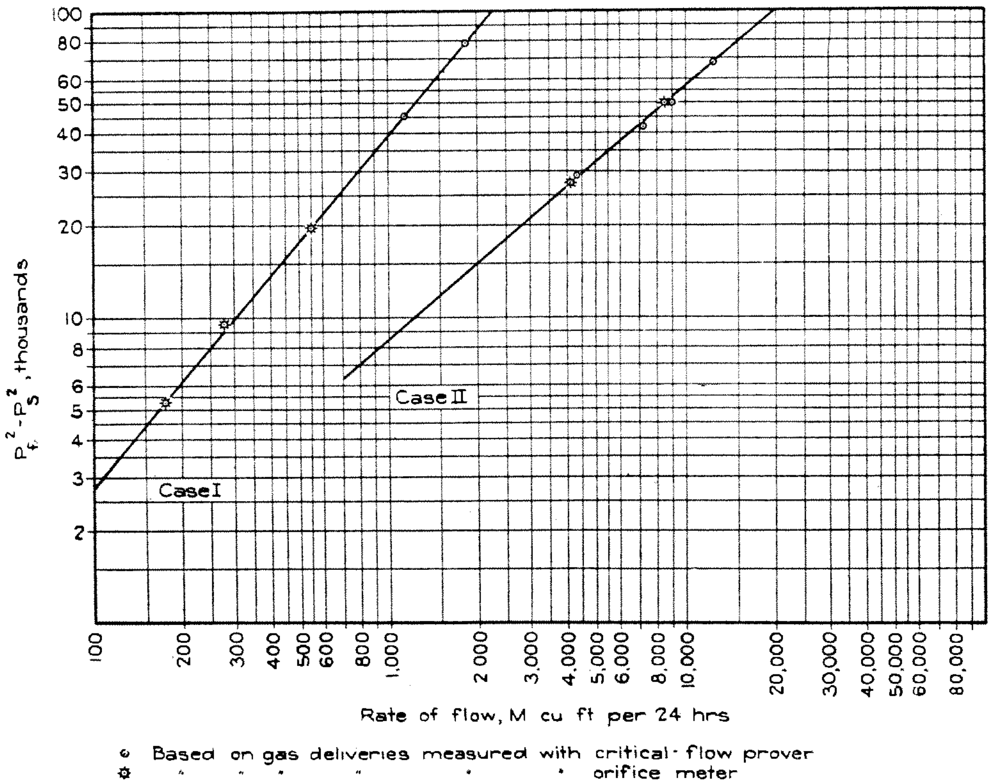


FIGURE 3.—Measurement of gas deliveries with critical-flow prover and orifice meter for same back-pressure tests on natural-gas wells

vented to the atmosphere and it is impracticable to use the orifices in a critical-flow prover on account of excessive gas pressure or because of the damaging effect of abrasive materials carried in the gas stream.[15] The range of delivery rates that can be measured with choke nipples is determined by the pressure available and the sizes of openings in the choke nipples. Manipulation of the sizes of flow area in the choke nipples while a back-pressure test is conducted is similar to using different sizes of orifices in the critical-flow prover.

A detailed discussion of the use of choke nipples for measuring rates of flow of gas is given in appendix 3.

[15] This is especially true when soft stainless-steel orifice plates, as used by the authors, are part of the critical-flow-prover equipment. Some investigators have used orifice plates of hard steel to withstand the damaging effect of abrasive materials carried in the gas stream, as reported by R. J. S. Pigott, Gulf Research Laboratories, Pittsburgh, Pa., in a letter to the authors.

MEASUREMENT OF GAS DELIVERY RATES WITH PITOT TUBE

The Pitot tube can be used to measure rates of delivery of gas from a well during a back-pressure test, but not as advantageously as a critical-flow prover or choke nipples. In using Pitot tubes the flows of gas from the well must be regulated by a valve on the wellhead, and usually the opening from which the gas is discharged from the wellhead is but a short distance from the regulating valve; therefore, there is a change in the direction of flow of the gas which sometimes causes errors in measurement due to flow disturbances over the area of the discharge opening.

The Pitot tube was used by the authors to measure rates of flow of gas under open-flow conditions from many of the wells on which back-pressure tests were conducted, and comparisons of the open-flow delivery rates obtained with the Pitot tube and from interpretation of the back-pressure data (similar to comparisons in fig. 8) have been made.

A detailed discussion of the use of a Pitot tube for measuring rates of flow from gas wells is given in appendix 4.

MEASUREMENT OF RATES OF GAS DELIVERY UNDER CONDITIONS OF NONCRITICAL FLOW WITH ORIFICE-TYPE EQUIPMENT OTHER THAN ORIFICE METERS

Rates of delivery from gas wells can be measured under conditions of noncritical flow [16] with a funnel meter,[17] an orifice well tester,[18] or any other orifice-type equipment. The orifice well tester is similar in construction to the so-called critical-flow prover, but the orifices in the tester are subjected to such pressure and flow conditions that the flow is noncritical instead of critical. The flow of gas is vented to the atmosphere from both the funnel meter and the orifice well tester, and the rates of delivery that can be measured under noncritical-flow conditions are limited by the low pressures under which these instruments can be used and the sizes of openings through which the gas is delivered. Accurate measurement of delivery rates under conditions of noncritical flow is difficult to obtain. When an orifice well tester is used the orifice should not be near any change in the direction of the flow of gas or obstruction to gas flow, and the measuring equipment should be an appreciable distance from the wellhead to minimize the effect of disturbances caused by its fittings. Often the causes of disturbances in noncritical flow are difficult to locate, and eddies in the gas stream caused by flow through the wellhead fittings are difficult to eliminate, so every precaution should be taken to prevent disturbances to the flow of the gas approaching the orifice.

[16] Rawlins, E. L. (Bureau of Mines), Flow of Air and Gas through Small Orifces: Oil and Gas Jour., May 10, 1928, p. 111. See appendix 2 of this report.
[17] Lichty, L. C., Measurement, Compression, and Transmission of Natural Gas: John Wiley & Sons, New York, p. 239.
[18] Diehl, John C., Natural-Gas Handbook: Metric Metal Works, Erie, Pa., pp. 284-289.

METHODS OF COMPUTING RESULTS OF BACK-PRESSURE TESTS ON NATURAL-GAS WELLS

Computations of the results of a back-pressure test on a natural-gas well involve the following steps:

1. Computing pressures at the sand from pressure and volume observations made at the wellhead.
2. Determining values of the pressure factor $P_f^2-P_s^2$ (absolute shut-in formation pressure squared minus back pressure at the sand squared) and rates of delivery from the well corresponding to these pressure factors.
3. Plotting on logarithmic coordinate paper values of Q (rate of delivery) against corresponding values of the pressure factor $P_f^2-P_s^2$.
4. Determining values of the exponent n and the coefficient C of the flow equation,

$$Q=C(P_f^2-P_s^2)^n.$$

Determinations of n and C are not necessary for most routine interpretations made from back-pressure data, but occasionally their values can be used for special interpretations.

5. Determining the absolute open flow [19] or the rate of delivery from the well under any desired pressure condition from the plotted relationship.
6. Comparing absolute open flow with maximum deliveries that could be produced through different sizes of producing strings.

COMPUTING PRESSURES AT THE SAND IN A GAS WELL BASED UPON PRESSURE AND VOLUME OBSERVATIONS AT WELLHEAD

Since an interpretation of gas availabilities is based upon pressures existing in the sand it is necessary to calculate the pressures in the sand from observations of pressures at the wellhead unless the pressures are obtained at the bottom of the well with a bottom-hole pressure instrument. Factors influencing the calculation of bottom-hole pressures from observations of pressure at the wellhead for normal gas wells (particularly where liquid does not accumulate in the well) are such that reliable information can be obtained without using bottom-hole pressure instruments. As explained previously and illustrated in figure 2 values must be calculated for the shut-in formation pressure P_f and the back pressure at the sand face P_s.

The absolute formation pressure P_f in a well is determined under static conditions and is equal to the observed absolute pressure P_c at the wellhead plus the pressure due to the weight of the column of gas in the well.

The absolute back pressure at the sand face P_s is determined under flowing conditions and is equal to the observed absolute working pressure P_w at the wellhead plus the pressure drop due to friction in the producing string plus the pressure due to the weight of the moving gas column. The differential pressure required to accelerate the gas from its velocity at the bottom of the well to its velocity at the wellhead also is a factor but generally is a minor or negligible one in normal flow of gas through the producing strings of gas wells.

In a producing gas well that contains a continuous, unobstructed, and confined column of static gas extending from the producing

[19] The term absolute open flow, as used in this report, is the number of cubic feet of gas per 24 hours that would be produced by a well if the only pressure against the face of the producing sand in the well bore were atmospheric pressure.

sand to the wellhead, the absolute back pressure at the sand face P_s is equal to the absolute pressure of the static column at the wellhead plus the pressure due to the weight of that column. For example, if a well is producing through tubing only and there are no perforations in the tubing above the producing stratum, and if there is no leakage from the annular space around the tubing and no packer or other obstruction in it to prevent free equalization of pressure between the producing sand and the wellhead, the absolute back pressure at the sand P_s may be computed by determining the absolute wellhead pressure of the static column of gas in the annular space and adding the pressure due to the weight of that column.

Pierce and Rawlins [20] discuss in detail the basis of calculations to determine the pressure due to the weight of a column of gas in a well and the pressure drop due to friction in the producing string and give charts which can be used to facilitate the calculations of these factors. Calculations subsequently have been simplified, and six tables have been prepared by the authors (see appendix 5) which are readily adaptable for routine computation of the results of back-pressure tests of gas wells.

EFFECT OF DEVIATION OF GASES FROM BOYLE'S LAW ON COMPUTATIONS OF WEIGHT OF A COLUMN OF GAS

The effect of the deviation of gases from Boyle's law [21] on the pressure due to the weight of static and moving columns of gas is discussed in detail in appendix 6.

PRESSURE AND FLOW DATA USED TO DETERMINE RELATIONSHIPS BETWEEN Q AND $(P_f^2 - P_s^2)$

Only three factors, the shut-in formation pressure P_f, the back pressures at the sand face P_s, and the rates of flow Q, corresponding to the different back pressures at the sand face, are used in plotting the data from which the relationship between Q and $P_f^2 - P_s^2$ is determined and from which interpretations of a well's ability to produce gas are made. Calculations are made of the factor $P_f^2 - P_s^2$ (shut-in formation pressure squared minus back pressure at the sand face squared) and the rate of flow Q. The values of the squares of pressures corresponding to pressures ranging from 10 to 2,500 pounds per square inch are given in table 38 of appendix 5, and this table can be used to determine the square of the shut-in formation pressure and the squares of different back pressures at the sand face. The square of the shut-in formation pressure minus each of the squares of the back pressures at the sand face then can be obtained by subtraction.

GRAPHIC PRESENTATION OF DATA OBTAINED FROM BACK-PRESSURE TESTS

The pressure factors $P_f^2 - P_s^2$ obtained from the calculation of back-pressure test data are plotted on logarithmic coordinate paper against the corresponding rates of flow. The results of back-pressure tests on a number of gas wells are illustrated graphically in

[20] Work cited in footnote 5.

[21] Johnson, T. W., and Berwald, W. B., Deviation of Natural Gas from Boyle's Law: Tech. Paper 539, Bureau of Mines, 1932, 29 pp.

figure 4, where the relationship between the rate of flow is Q and the pressure factor $P_f^2-P_s^2$, as determined by the plotted points, is represented graphically by a straight line. This line can be extended [22] beyond the range of the plotted points, and thereby it is possible to read directly the rate of flow corresponding to any pressure factor.

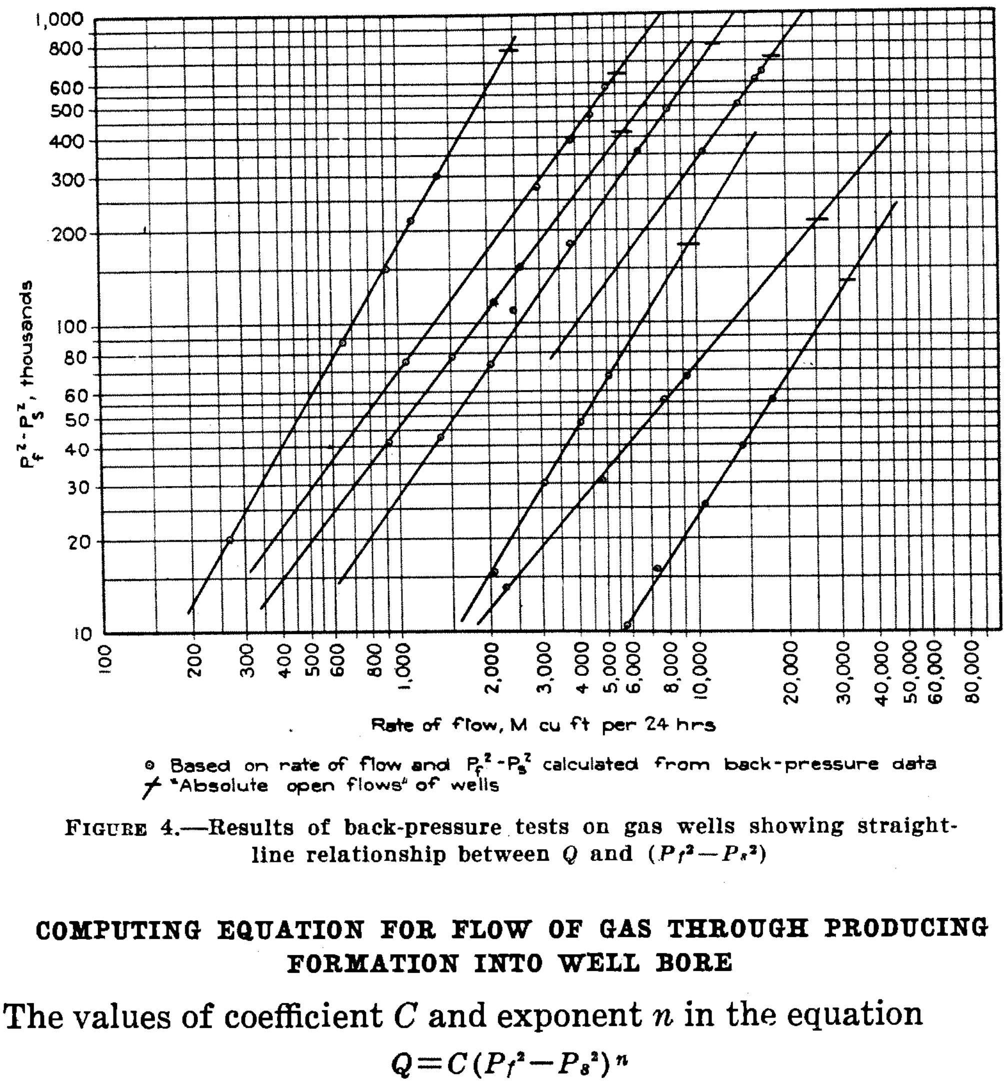


FIGURE 4.—Results of back-pressure tests on gas wells showing straight-line relationship between Q and $(P_f^2-P_s^2)$

COMPUTING EQUATION FOR FLOW OF GAS THROUGH PRODUCING FORMATION INTO WELL BORE

The values of coefficient C and exponent n in the equation

$$Q=C(P_f^2-P_s^2)^n$$

for flow of gas through the producing formation into the well bore, for a particular back-pressure test, are determined from the straight-line relationship illustrated in figure 5. The exponent n of the flow equation is the tangent of the angle A (determined by direct measurement or by mathematical calculation) between the straight line and the pressure ordinate. The value of n (fig. 5) is equal to $\frac{x}{y}$, which by measurement is approximately 0.707.

The mathematical calculation of the value of n is based upon the definition of a straight line,[23] where

$$x_1-x_2=n\ (y_1-y_2).$$

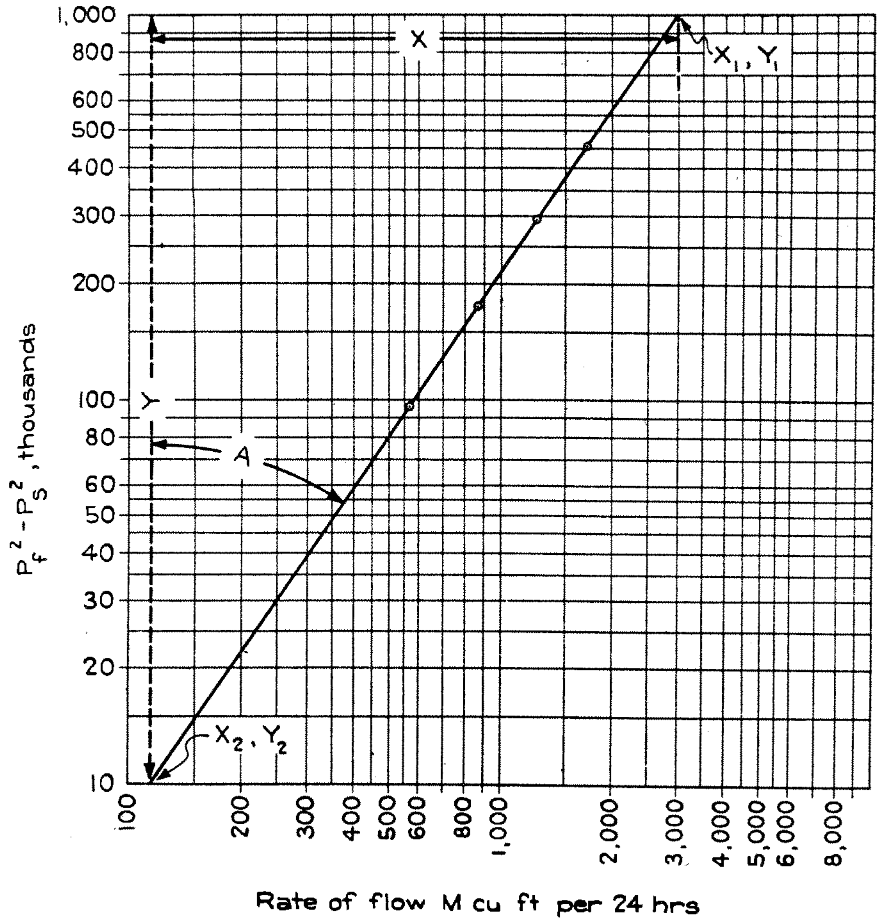
[22] See discussion of Study of Specific Natural-Gas Well.
[23] See any textbook on analytical geometry.

Values in figure 5 have been selected, so that

$$x_1 = \log 3{,}000{,}000 = 6.47712,$$
$$x_2 = \log 116{,}000 = 5.06446,$$
$$y_1 = \log 1{,}000{,}000 = 6.00000, \text{ and}$$
$$y_2 = \log 10{,}000 = 4.00000.$$

Therefore,

$$n = \frac{x_1 - x_2}{y_1 - y_2} = \frac{6.47712 - 5.06446}{6-4} = \frac{1.41266}{2} = 0.70633.$$



$$n = \text{Tangent } A = \frac{X_1 - X_2}{Y_1 - Y_2} = \frac{X}{Y}$$

$$X = \text{Log } Q_1 - \text{Log } Q_2$$

$$Y = \text{Log}(P_f^2 - P_s^2)_1 - \text{Log}(P_f^2 - P_s^2)_2$$

$$\text{Log } C = \text{Log } Q - n \text{ Log}(P_f^2 - P_s^2)$$

FIGURE 5.—Graphical representation of factors in the equation for flow of gas through the producing formation into the well bore, $Q = C(P_f^2 - P_s^2)^n$

The coefficient C is calculated by substituting values for symbols in the equation of flow,

$$Q = C(P_f^2 - P_s^2)^n,$$

from which

$$\log Q = \log C + n \log (P_f^2 - P_s^2),$$

and

$$\log C = \log Q - n \log (P_f^2 - P_s^2).$$

Values have been selected in figure 5, so that $\log Q = \log 3{,}000{,}000 = 6.47712$, and the corresponding $\log (P_f^2 - P_s^2) = \log 1{,}000{,}000 = 6.00000$.

Therefore,

$$\log C = 6.47712 - (0.70633)\ (6.0),$$
$$= 2.23914,$$

from which $C = 173.44.$

Substituting the values of n and C in the equation of flow, the following relationship is obtained:

$$Q = 173.44\,(P_f^2 - P_s^2)^{0.70633}.$$

DETERMINATION OF ABSOLUTE OPEN FLOW

The term "open flow" has been used freely in contracts and in regulatory documents, but little qualification of its meaning as applied to the description of the ability of a natural-gas well to produce gas has been published. An open-flow test is described by Porter [24] as "a test made to determine the volume of gas that will flow from a well in a given time when the large valves are wide open." When the rate of flow of gas from a well is gaged with the "large valves wide open" the well should be blown to the atmosphere until the flow has become stabilized. Stabilization of pressures within the well and the reservoir sand usually is considered to occur when a Pitot-tube reading at the wellhead does not change during a 15-minute period.[25] In general routine field testing, however, observations often are made after the first 15-minute period during which gas is blown to the atmosphere, whether or not conditions in the well and reservoir are stabilized. Such tests therefore are liable to give inaccurate results.

Results of a back-pressure test of a gas well also should be based upon stabilized pressures in order that determination of the rates of flow (based on back-pressure data) that would occur if the well were open to the atmosphere will indicate the open-flow rates under stabilized flow conditions.

The term "absolute open flow" as used in this report refers to the number of cubic feet of gas per 24 hours that would be produced by a well if the only pressure against the face of the producing sand in the well bore were atmospheric pressure.

The absolute open flow of any well can be ascertained directly from the chart on which rate of flow Q is plotted against the corresponding pressure factor $P_f^2 - P_s^2$. The straight line defining the relationship between Q and $P_f^2 - P_s^2$ is extended so the value of rate of flow Q corresponding to the value of $P_f^2 - P_s^2$, where P_s is equivalent to atmospheric pressure, can be read by extrapolation. Q then is the absolute open flow of the well in cubic feet per 24 hours. In most wells, especially those having high shut-in formation pressures, the value of P_s can be neglected in calculating $P_f^2 - P_s^2$.

The value of the absolute open flow also can be computed from the equation

$$Q = C\,(P_f^2 - P_s^2)^n,$$

but since computations made by the use of the equation for routine purposes are cumbersome the best practice is to read the open-flow rates directly from plotted relationships. The equation, however,

[24] Porter, Hollis P., Petroleum Dictionary for Office, Field and Factory: 1st ed., Gulf Publishing Co., Houston, Tex., p. 142.
[25] Diehl, John C., Natural-Gas Handbook: Metric Metal Works, Erie, Pa., 1927, p. 290.

can be used to show mathematically the variation in absolute open flow with changes in atmospheric pressure. This variation in different gas-producing areas or with changes in the atmospheric pressure in the same gas-producing area usually is negligible and need not be taken into consideration in determining flow rates when the shut-in formation pressure is greater than 100 pounds per square inch absolute. For example, if the shut-in formation pressure is 100 pounds per square inch absolute and the atmospheric pressure is 15 pounds per square inch absolute the value of $P_f^2-P_s^2$ defining absolute open-flow conditions would be

$$(P_f^2-P_s^2) = (\overline{100^2}-\overline{15^2}) = (10{,}000-225) = 9{,}775.$$

On the other hand, if the shut-in formation pressure is 100 pounds per square inch absolute and the atmospheric pressure is 12 pounds per square inch absolute, the value of $P_f^2-P_s^2$ would be

$$(P_f^2-P_s^2) = (\overline{100^2}-\overline{12^2}) = (10{,}000-144) = 9{,}856.$$

A small difference in the values of pressure factor $P_f^2-P_s^2$ for the two conditions of atmospheric pressure would cause only a minor percentage variation in the observed absolute open-flow readings, and furthermore the differences are less in proportion and the percentage variation smaller for higher values of the shut-in formation pressure.

The effect of variation in atmospheric pressure on interpretation of absolute open flow should be considered, however, if the well has a low (less than 100 pounds per square inch absolute) shut-in formation pressure. A comparison of the delivery capacities of different gas wells can be based on any average back pressure at the sand (for example, 15 pounds per square inch absolute), but it should be remembered that small changes in the back pressure have a much greater effect on the delivery rates in low-pressure wells than corresponding changes of pressure in high-pressure wells. Consider, for example, that back-pressure tests on two gas wells having shut-in formation pressures of 25 pounds per square inch absolute gave rates of delivery of gas of 300,000 cubic feet per 24 hours from each well and that the calculation for one well was based on a back pressure at the sand of 15 pounds per square inch absolute and that for the other well on a back pressure at the sand of 13 pounds per square inch absolute. Assume further that the value of n in the equation

$$Q=C(P_f^2-P_s^2)^n$$

is 0.75. If the open-flow capacities of the two wells are to be compared on the basis of a back pressure at the sand face of 15 pounds per square inch absolute it is necessary to use that pressure as a basis in calculating the open-flow capacity of the well producing 300,000 cubic feet of gas per 24 hours at a back pressure of 13 pounds per square inch. Thus, since

$$Q=C(P_f^2-P_s^2)^n,$$

by substitution

$$300{,}000=C(\overline{25^2}-\overline{13^2})^{0.75},$$

and

$$C=3040.13.$$

If P_s, the back pressure at the sand face, is 15 pounds per square inch then

$$Q=3040.13(\overline{25^2}-\overline{15^2})^{0.75}=271{,}900 \text{ cubic feet per 24 hours.}$$

Therefore, for this well an increase in the back pressure at the sand from 13 to 15 pounds per square inch causes a decrease in the delivery rate from 300,000 to approximately 272,000 cubic feet of gas per 24 hours or $9\frac{1}{3}$ percent.

Gas deliveries from wells being produced under vacuum also can be compared under any desired conditions of pressure. Rates of delivery at back pressures of 5 and 15 pounds per square inch absolute at the face of the sand in the well for the two wells discussed above are shown in table 4.

TABLE 4.—*Comparison of rates of delivery at different back pressures from low-pressure gas wells*

Well no.	Shut-in formation pressure, lb. per sq. in. absolute, P_f	Back pressure at sand, lb. per sq. in. absolute, P_s	Exponent of relationship, $Q = C(P_f^2 - P_s^2)^n$, n	Rate of delivery, M cu. ft. per 24 hrs., Q
1	25	15	0.75	300.0
	..	5	..	406.6
2	25	13	.75	300.0
	..	15	..	271.9
	..	5	..	368.6

COMPARING ABSOLUTE OPEN FLOW WITH MAXIMUM DELIVERIES THAT COULD BE PRODUCED THROUGH DIFFERENT SIZES OF PRODUCING STRINGS

The difference between the absolute open flow of a gas well and the maximum delivery rate of gas from the well through any size of producing string is due to the back pressure imposed at the sand by pressure drop in the producing string due to friction, and that placed on the sand by the pressure due to the weight of the column of gas. The absolute open flow can be determined directly from the plotted results of a back-pressure test, and the maximum rates of delivery of gas from wells through any size of producing string can be determined by the " cut-and-try " method and by graphic methods discussed in detail in appendix 7.

STUDY OF A SPECIFIC NATURAL-GAS WELL

A convenient arrangement of data obtained from back-pressure tests of gas wells and the results of calculations of the data for a specific gas well are shown in table 5. A brief discussion of the testing procedure and an explanation of the calculation of data for this gas well can be used as a guide for conducting back-pressure tests on any gas well and interpreting the back-pressure data.

DESCRIPTION OF WELL

The well (table 5) is in the Texas Panhandle field, and at the time of the test was producing from a depth of 1,792 feet through $8\frac{1}{4}$-inch casing set at 1,563 feet. The top of the highest producing sandstone was 1,658 feet below the surface of the ground, and the well log indicated that there were 1 or 2 lower producing sandstone members. The gas was dry and had a specific gravity of 0.64. The shut-in pressure at the wellhead at the time of the test was 433 pounds per square inch absolute. The pressure and flow conditions stabilized quickly when back pressures were changed.

TABLE 5.—*Data and results of calculations for a back-pressure test on a natural-gas well*

..........Company

Well name and number: .... Date of test: September 8, 1930.
Location of well: ....
First sand: 1,658 feet; last sand: 1,792 feet. Total depth: 1,792 feet.
Diameter of casing: 8¼ inches; set at: 1,563 feet. Producing formation: ....
Size of tubing: .... inches; set at: not tubed. Producing through: 8¼-inch casing.
Specific gravity of gas: 0.64. L: 1,725 feet. GL: 1,100.
Shut-in pressure at wellhead, gage: 420 lb. per sq. in.
Barometer, lb. per sq. inch, 13.

Back-pressure test data

Reading	Working pressure at wellhead, gage	Gas-measurement data on: 4-inch critical-flow prover			
		Diameter of disk, inches	Coefficient	Upstream pressure, gage	Temperature, °F.
1	405	¾	223.2	405	65
2	391	1	396.4	391	65
3	370	1¼	615.0	370	65
4	343	1½	884.7	343	65

Calculation of rates of flow

1. $Q = (418 \times 223.2) \div \sqrt{0.64 \times 525} = 5{,}090$ M cu. ft. per 24 hours.
2. $Q = (404 \times 396.4) \div \sqrt{0.64 \times 525} = 8{,}740$ M cu. ft. per 24 hours.
3. $Q = (383 \times 615.0) \div \sqrt{0.64 \times 525} = 12{,}840$ M cu. ft. per 24 hours.
4. $Q = (356 \times 884.7) \div \sqrt{0.64 \times 525} = 17{,}180$ M cu. ft. per 24 hours.

Pressures

Reading	Shut-in wellhead pressure, lb. per sq. in. absolute, (P_c)	Pressure of gas column, lb. per sq. in.	Shut-in formation pressure, lb. per sq. in. absolute, (P_f)	Wellhead working pressure, lb. per sq. in. absolute, (P_w)	Equivalent, *GL*	*R*	Pressure drop, lb. per sq. in.	P_w plus pressure drop, lb. per sq. in. absolute, (P_1)	Pressure of gas column, lb. per sq. in.	Back pressure at sand, lb. per sq. in. absolute, (P_s)
1	433	17	450	418	0.02	13	nil	418	17	435
2	..	..	..	404	..	22	nil	404	16	420
3	..	..	..	383	..	32	1	384	15	399
4	..	..	..	356	..	45	3	359	14	373

Plotting data

Reading	P_f^2, thousands	P_s^2, thousands	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours
1	202.5	189.2	13.3	5,090
2	..	176.4	26.1	8,740
3	..	159.2	43.3	12,840
4	..	139.1	63.4	17,180

PREPARATIONS FOR BACK-PRESSURE TEST

Measurements of gas delivery were made with a critical-flow prover.[26] The installation of equipment for the back-pressure test is shown in figure 2. Critical-flow prover *A* was connected to the "top" gate valve. The thermometer well in the prover was filled with light-grade lubricating oil into which a mercurial thermometer was inserted for observing the flowing temperature of the gas. Vent *B* on the critical-flow prover allowed gas that might leak through the closed gate valves while orifice plates were being

[26] See appendix 2.

changed in the prover to be vented to the air. Two spring gages *C* were connected by $\frac{1}{4}$-inch copper tubing to the pressure tap on the prover and to a $\frac{1}{4}$-inch pressure tap, *E*, in the master gate. These gages were fastened to a special support, *F*, to eliminate vibration that would be obtained if they were fastened to the wellhead connections. The valves x, y, and z' were closed and x', y', and z open while observations were made of the pressures on the prover. When observations were being made of the pressures at the wellhead valves x', y', and z were closed and x, y, and z' open. A recording pressure gage, *D*, was used to study the behavior of wellhead pressures during the back-pressure test.

All gages were shaded from the sun during the back-pressure test. The gages were calibrated against a deadweight tester, and the pressure readings on the tester and the corresponding pressure indications of the gages were the same whether the test pressures were increased or decreased during calibration, so the gages were considered to be in good condition. Observations of the working pressures at the wellhead at different rates of gas delivery were made at a point below the wellhead fittings to eliminate the possibility of errors due to pressure drop through the fittings. The pressure observations made on the prover were used for calculating the gas delivery rates.

The pipe lines and connections to the well were inspected to make certain that no gas would leak into the lines through faulty valves during the test. Other possible sources of leakage also were inspected.

PROCEDURE OF BACK-PRESSURE TEST

Data obtained during the back-pressure test are shown in table 5. After the well had been closed until the pressure stabilized, the shut-in pressure at the wellhead as indicated by the calibrated spring gage was found to be 420 pounds per square inch gage. The flow valve on the well was opened, and gas was produced through a $\frac{3}{4}$-inch orifice in the critical-flow prover. This orifice was the only means used for regulating the gas flow. After the pressure and flow conditions became stable the working pressure at the wellhead was 405 pounds per square inch gage, the upstream pressure on the prover was 405 pounds per square inch gage, and the temperature of the flowing gas through the prover was 65° F. The well then was shut in and the $\frac{3}{4}$-inch orifice replaced with a 1-inch orifice. The well then was reopened and the flow regulated by the 1-inch orifice. After pressure and flow conditions stabilized the working pressure at the wellhead and the upstream pressure on the prover were 391 pounds per square inch gage. Subsequently, two similar sets of observations were made, using $1\frac{1}{4}$-inch and $1\frac{1}{2}$-inch orifices in the prover to regulate the flow of gas and to measure the rates of delivery. The working pressure at the wellhead was 370 pounds per square inch gage when the gas flowed through the $1\frac{1}{4}$-inch orifice and 343 pounds per square inch gage when the flow of gas was through the $1\frac{1}{2}$-inch orifice.

CALCULATION OF DELIVERY RATES

The delivery rates were calculated by the use of the critical-flow formula [27]

$$Q=\frac{CP}{\sqrt{GT}},$$

where Q=rate of flow, M cubic feet per 24 hours (14.4 pounds per square inch and 60° F.),
C=coefficient,[28]
P=upstream pressure, pounds per square inch absolute,
G=specific gravity of gas (air=1.00),
T=temperature of flowing gas, °F. absolute.

From the first set of observations on this well the upstream pressure was found to be 418 pounds per square inch absolute and the temperature 525 (65+460)° F. absolute. The specific gravity of the gas was 0.64 and the coefficient applicable to the ¾-inch orifice 223.2. Therefore, the rate of flow of gas through the ¾-inch orifice was

$$Q=\frac{CP}{\sqrt{GT}}=\frac{223.2\times 418}{\sqrt{0.64\times 525}}=5{,}090{,}000 \text{ cubic feet of gas per 24 hours.}$$

The rates of flow of gas through the 1-inch, 1¼-inch, and 1½-inch orifices were computed to have been 8,740,000, 12,840,000, and 17,180,000 cubic feet of gas per 24 hours, respectively.

Therefore, a comprehensive range in delivery rates from 5,090,000 to 17,180,000 cubic feet of gas per 24 hours, corresponding to a range in back pressures at the wellhead of 418 to 356 pounds per square inch absolute, was obtained for this well, and the back pressure at the wellhead was not lower than 82 percent of the shut-in wellhead pressure at any time during the test.

CALCULATION OF PRESSURES AT THE SAND

The calculations of the pressures at the sand are made as follows: [29]

Step 1. Calculate P_f, the shut-in formation pressure in the reservoir.
- *a.* Shut-in wellhead pressure=420+13=433 pounds per square inch absolute.
- *b.* $GL=0.64\times 1{,}725=1{,}100$.
- *c.* Weight of static gas column corresponding to a pressure at the wellhead of 433 pounds per square inch and a GL of 1,100, from table 37 of appendix 5,=17 pounds per square inch.
- *d.* Therefore, $P_f=433+17=450$ pounds per square inch absolute.

Step 2. Calculate values of P_s, the back pressure at the sand, corresponding to different rates of flow.
- *a.* The working pressure P_w at the wellhead corresponding to the rate of flow of 5,090,000 cubic feet per 24 hours=405+13=418 pounds per square inch absolute. Similarly, the values of P_w for the second, third, and fourth observations are respectively 404, 383, and 356 pounds per square inch absolute.
- *b.* Since GL for the 8¼-inch casing=1,100, the equivalent GL (GL for 1-inch tubing equivalent to a GL of 1,100 for 8¼-inch casing) as obtained from table 33 of appendix 5 is 0.02.
- *c.* The value of R, corresponding to the observed rate of flow of 5,090,000 cubic feet per 24 hours and an equivalent GL of 0.02 feet is $1.27\times 10{\pm}13$ (see table 34, appendix 5). Similarly, values

[27] See appendix 2.
[28] The coefficients used for computing the rates of flow were for the no. 4 set of orifices as shown in table 26 of appendix 2.
[29] See appendix 5 for explanation of procedure.

of R corresponding to rates of flow of 8,740,000, 12,840,000, and 17,180,000 cubic feet per 24 hours are respectively 22, 32, and 45.

d. The pressure drop in the producing string corresponding to $R=13$ and a pressure at the wellhead of 418 pounds per square inch absolute is negligible, as shown by table 35 of appendix 5. The pressure drop also is negligible when $R=22$ and the wellhead pressure is 404 pounds per square inch absolute. The pressure drop for the third observation, when $R=32$ and the pressure at the wellhead is 383 pounds per square inch absolute, is 1 pound per square inch; and that for the fourth observation, corresponding to $R=45$ and a wellhead pressure of 356 pounds per square inch absolute, is 3 pounds per square inch.

e. The value of P_1 (working pressure at wellhead plus the pressure drop due to friction) for the first observation is $418+0=418$ pounds per square inch absolute. Similarly, values of P_1 for the second, third, and fourth observations are respectively 404, 384, and 359 pounds per square inch absolute.

f. The value of the pressure ratio P_w/P_1 for each of the four readings is approximately unity.

g. The value of the correction factor F is unity (table 36, appendix 5).

h. GLF is the same as GL, 1,100.

i. The pressure due to the weight of the moving column of gas for the first observation corresponding to a GLF of 1,100 and a value of P_1 of 418 pounds per square inch absolute is 17 pounds per square inch (table 37, appendix 5). Similarly, the values of the pressure due to the weight of the moving column of gas for the second, third, and fourth observations are 16, 15, and 14 pounds per square inch, respectively.

j. Since $P_s=P_1+$pressure due to the weight of the column of gas, P_s for the first reading is $418+17$ or 435 pounds per square inch absolute. Similarly, values of P_s for the second, third, and fourth reading are respectively 420, 399, and 373 pounds per square inch absolute.

CALCULATION OF PRESSURE FACTOR $P_f^2-P_s^2$

Pressure factor $P_f^2-P_s^2$ is calculated as follows:

1. $P_f^2=(450)^2=202{,}500$ (table 38, appendix 5).
2. P_s^2, corresponding to a rate of delivery of 5,090,000 cubic feet per 24 hours$=(435)^2=189{,}200$. Similarly, values of P_s^2 corresponding to rates of flow of 8,740,000, 12,840,000, and 17,180,000 cubic feet per 24 hours are 176,400, 159,200, and 139,100 respectively (table 38, appendix 5).
3. The value of $P_f^2-P_s^2$ corresponding to a rate of flow of 5,090,000 cubic feet per 24 hours$=202{,}500-189{,}200=13{,}300$. Similarly, values of $P_f^2-P_s^2$ corresponding to rates of flow of 8,740,000, 12,840,000, and 17,180,000 are 26,100, 43,300, and 63,400 respectively.

GRAPHIC PRESENTATION OF DATA

Values of $P_f^2-P_s^2$ of 13,300, 26,100, 43,300, and 63,400 were plotted against the respective rates of flow of 5,090,000, 8,740,000, 12,840,000, and 17,180,000 cubic feet of gas per 24 hours on logarithmic paper, as shown in figure 6. A straight line, A, drawn through the four plotted points represents the relationship between the rate of flow Q and pressure factor $P_f^2-P_s^2$ under any condition of pressure at the time of the back-pressure test.

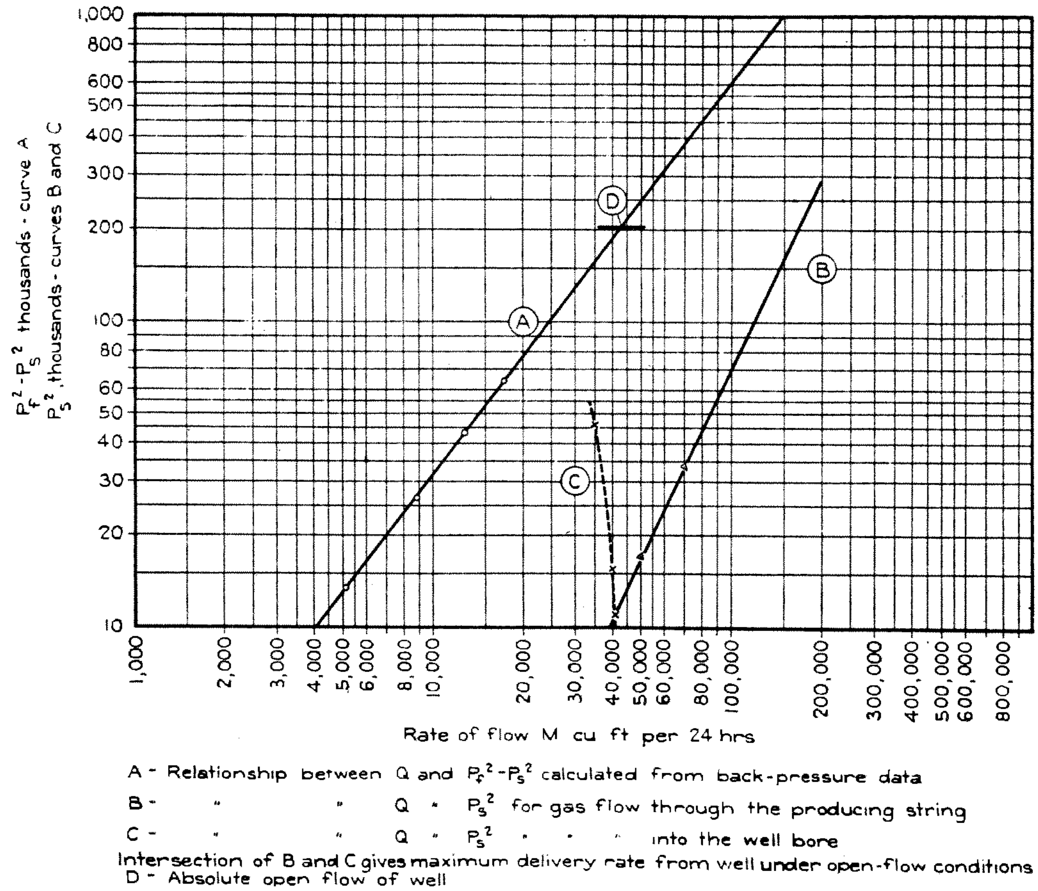


FIGURE 6.—Results of back-pressure test on a natural-gas well

COMPUTING EQUATION FOR FLOW OF GAS THROUGH PRODUCING FORMATION TO WELL BORE

The line *A* (fig. 6) is represented by the mathematical expression

$$Q = C(P_f^2 - P_s^2)^n.$$

The values of n and C are calculated from the back-pressure data for this well as follows:

1. Calculation of n.
   a. Values of $P_f^2 - P_s^2$ of 100,000 and 10,000 corresponding to values of Q of 24,600,000 and 4,050,000 cubic feet per 24 hours respectively are selected in figure 6.

   b.
$$n = \frac{\log 24{,}600{,}000 - \log 4{,}050{,}000}{\log 100{,}000 - \log 10{,}000},$$
$$= \frac{7.39094 - 6.60746}{5.00000 - 4.00000} = 0.7835.$$

2. Calculation of C.
   a. The value of Q of 24,600,000 cubic feet per 24 hours with the corresponding value of $P_f^2 - P_s^2$ of 100,000 is selected as the basis of calculation.

   b. Since from the formula

$$Q = C(P_f^2 - P_s^2)^n,$$

   the value of C is expressed as follows:

$$\text{Log } C = \log Q - n \log (P_f^2 - P_s^2).$$

By substitution,

$$\log C = \log 24{,}600{,}000 - 0.7835 \log (100{,}000),$$
$$= 7.39094 - 0.7835(5.00000),$$
$$= 7.39094 - 3.91750,$$
$$= 3.47344;$$

therefore $C = 2974.7$.

3. Hence, the equation of flow is

$$Q = 2974.7 (P_f^2 - P_s^2)^{0.7835}.$$

DETERMINATION OF ABSOLUTE OPEN FLOW

Line A (fig. 6) is extended until it intersects a line drawn horizontally representing the value of $P_f^2 - P_s^2$ equivalent to P_f^2 or 202,500. The effect of atmospheric pressure or the equivalent of a back pressure at the sand of 13 pounds per square inch is negligible in the calculation for this well and the absolute open flow therefore is read directly from the plotted relationship to be approximately 42,800,000 cubic feet of gas per 24 hours.

DETERMINATION OF OPEN FLOW THROUGH 8¼-INCH CASING

The open flow through 8¼-inch casing [30] for the well (see fig. 6) is determined as follows:

1. $GL = 1{,}100$.
2. The equivalent GL (GL for 1-inch tubing equivalent to GL of 1,000 for 8¼-inch casing) is 0.02 (table 33, appendix 5).
3. Assume delivery rates of 50,000,000 and 70,000,000 cubic feet of gas per 24 hours. From table 34 of appendix 5, the values of R corresponding to an equivalent GL of 0.02 and flows of 50,000,000 and 70,000,000 cubic feet of gas per 24 hours are, respectively, 127 and 178. Since, under these conditions, $P_1 = R$ (approximately), as shown by table 35 of appendix 5, the values of P_1 corresponding to flow rates of 50,000,000 and 70,000,000 cubic feet per 24 hours are 127 and 178 pounds per square inch, respectively.
4. The ratios of P_w/P_1 are $\frac{13}{127}$ and $\frac{13}{178}$ or 0.102 and 0.073, respectively.
5. Correction factor F from table 36 of appendix 5, corresponding to each flow rate, is 0.67.
6. Therefore, GLF corresponding to each flow rate is 737.
7. From table 37 of appendix 5, the weight of the column of gas corresponding to a GLF of 737 and a P_1 of 127 is 3 pounds per square inch; and for a GLF of 737 and a P_1 of 178 the weight of the column of gas is 5 pounds per square inch.
8. The value of P_s corresponding to the flow rate for this well of 50,000,000 cubic feet of gas per 24 hours equals 127 plus 3 or 130 pounds per square inch absolute and that corresponding to 70,000,000 cubic feet of gas per 24 hours equals 178 plus 5 or 183 pounds per square inch absolute.
9. The values of P_s^2 corresponding to 50,000,000 and 70,000,000 cubic feet of gas per 24 hours are $(130)^2$ and $(183)^2$ or 16,900 and 33,490, respectively.
10. The coordinates defined by the corresponding values of P_s^2 and rates of flow Q establish the relationship expressed by line B (fig. 6), which gives the maximum capacities of the 8¼-inch casing to produce gas corresponding to different pressures at the sand.

[30] See appendix 7 for description of methods of determining maximum delivery through any size of producing string.

11. The following tabulation shows different values of P_s^2 with corresponding values of Q, as determined from the plotted relationship between Q and $P_f^2-P_s^2$ from the back-pressure test on the gas well.

Rate of flow, M cu. ft. per 24 hours, Q	$P_f^2-P_s^2$, thousands	P_f^2, thousands	P_s^2, thousands
35,000	157.0	202.5	45.5
40,000	187.0		15.5
42,000	191.5		11.0

12. Line C represents graphically the relationship between Q and P_s^2 as obtained in item 11 and indicates the ability of the sand to produce gas at different back pressures at the sand face in the well bore.
13. The intersection of B and C at a rate of flow of gas of approximately 41,000,000 cubic feet per 24 hours gives the open flow of the well through 8¼-inch casing.

SUMMARY OF RESULTS OF BACK-PRESSURE TEST

The results of the back-pressure test on the gas well (see fig. 6) show that the relationship between rate of flow Q in cubic feet per 24 hours and pressure factor $P_f^2-P_s^2$, where P_f is the absolute shut-in formation pressure and P_s is the absolute back pressure at the sand face, can be expressed by a straight line (on logarithmic paper) whose equation is

$$Q=2974.7(P_f^2-P_s^2)^{0.7835}.$$

The absolute open flow of the gas well is approximately 42,800,000 cubic feet of gas per 24 hours, and the open flow through 8¼-inch casing is approximately 41,000,000 cubic feet of gas per 24 hours. Figure 6 can be used as a basis for determining rates of delivery corresponding to different back pressures at the sand face. For example, if the back pressure at the sand is 90 percent of the shut-in formation pressure, or 405 pounds per square inch absolute, the rate of gas delivery is that corresponding to a $P_f^2-P_s^2$ of 38,500, or 11,700,000 cubic feet of gas per 24 hours. This rate of flow is equivalent to 27.3 percent of the absolute open flow and to 28.5 percent of the open flow through 8¼-inch casing.

CAUSE AND EFFECT OF ERROR IN BACK-PRESSURE TEST DATA

Sometimes the results obtained when the back-pressure method for gaging gas-well deliveries is applied appear to be inconsistent. The inconsistencies usually are caused by the influence of factors that result in errors in the calculated values of the pressure at the face of the sand or to incorrect measurement of the volume of gas delivered from the well. The results of back-pressure tests on gas wells can be interpreted properly only when there is thorough understanding of the cause and effect of error in back-pressure data. This is discussed in detail in appendix 8.

FLOW OF GAS THROUGH POROUS MEDIA

Experimental tests were conducted by the authors to determine the character of gas flow through different kinds of porous media under different pressure and flow conditions. The apparatus used, the procedure of testing, and the general results of the tests as they can be applied to natural-gas production operations are described in detail in appendix 9. The principal results, as indicated by the tests which can be used as a background in discussing the application of back-pressure data to production problems, are:

1. The relationship between the rate of flow Q and the pressure factor is applicable regardless of the actual values of the pressures—the difference of squares of the pressures is the controlling factor.
2. The shape and size of the sand grain has an appreciable effect on coefficient C and exponent n of the flow equation.
3. The distance of travel of the gas and diameter of the flow tubes influence only coefficient C of the flow equation.
4. For all practical purposes, the porosity of the packed porous media affected only coefficient C of the flow equation.

APPLICATION OF BACK-PRESSURE TESTS TO NATURAL-GAS PRODUCTION PROBLEMS

During the progress of the study of gaging gas-well deliveries discussed in this report, 966 back-pressure tests were made on 582 gas wells, in Oklahoma, Kansas, Texas, Louisiana, Wyoming, Montana, California, West Virginia, and Pennsylvania. The relationships between the rates of flow Q and the pressure factors $P_f^2-P_s^2$ for 850 of the tests (88 percent of the total tests conducted) could be expressed by straight lines on logarithmic paper. Curves could be drawn to represent the relationships between Q and the pressure factors for 78 of the tests (8 percent of the total), and in 38, or approximately 4 percent of the tests, the plotted points were spaced too irregularly on the logarithmic paper to permit the establishment of definite relationships between the rates of flow and the pressure factors. The computed values of n in the equation of the straight-line relationship $Q=C(P_f^2-P_s^2)^n$ varied widely, as shown in table 6. The results of back-pressure tests listed in table 6 include all of the tests made on wells where the calculations showed straight-line relationships between rate of flow Q and pressure factor $P_f^2-P_s^2$.

Only one back-pressure test was made on many of the wells considered in the table, and that test was conducted under the conditions existing during normal operation of the well, regardless of liquid conditions within the gas reservoir or in the well bore. The back-pressure data for many of the wells were obtained over limited ranges of pressure and flow conditions, and though the results indicated straight-line relationships it is possible that if data could have been obtained over wider ranges of pressure and flow conditions the relationships between Q and $P_f^2-P_s^2$ would have been represented by curves similar to those obtained on wells subject to liquid accumulation. As indicated in table 6 comparatively few of the tests gave straight lines with values of n less than 0.5 or greater than 1.2. The authors believe that by conducting back-pressure tests periodically, observing shut-in pressures before and after periods of heavy withdrawal, applying remedial measures to improve the ability of the wells to produce gas, and taking into account the possible effects of liquid accumulation in the sand and in the well bore, either an explanation can be found for large values of n or the wells can be improved to decrease the value of the exponent. Most of the tests (table 6) that gave exponents greater than 1.2

were conducted on wells producing under conditions where liquid accumulation might have had appreciable effects on the abilities of the wells to produce gas. Careful study of the data indicates that the average well had a value of n in the flow equation of 0.6 to 1.2 and a weighted general average of approximately 0.85.

Back-pressure data generally include the same range of pressure and flow conditions as those under which the well operates, and if correct assumptions are used in computing pressures at the sand from the pressure indications at the wellhead the results are indicative of the ability of the well to produce gas under these conditions, whether the resulting relationships between Q and $P_f^2-P_s^2$ seem consistent or not. Results of tests on gas wells where the relationships between Q and $P_f^2-P_s^2$ seem inconsistent stress the importance of thorough studies of the wells, and the need for data to analyze the producing characteristics of the wells throughout wide ranges of pressure and flow conditions.

TABLE 6.—*Variation of value of n in the flow equation $Q = C(P_f^2 - P_s^2)^n$, for back-pressure tests conducted while studying the gaging of gas-well deliveries*

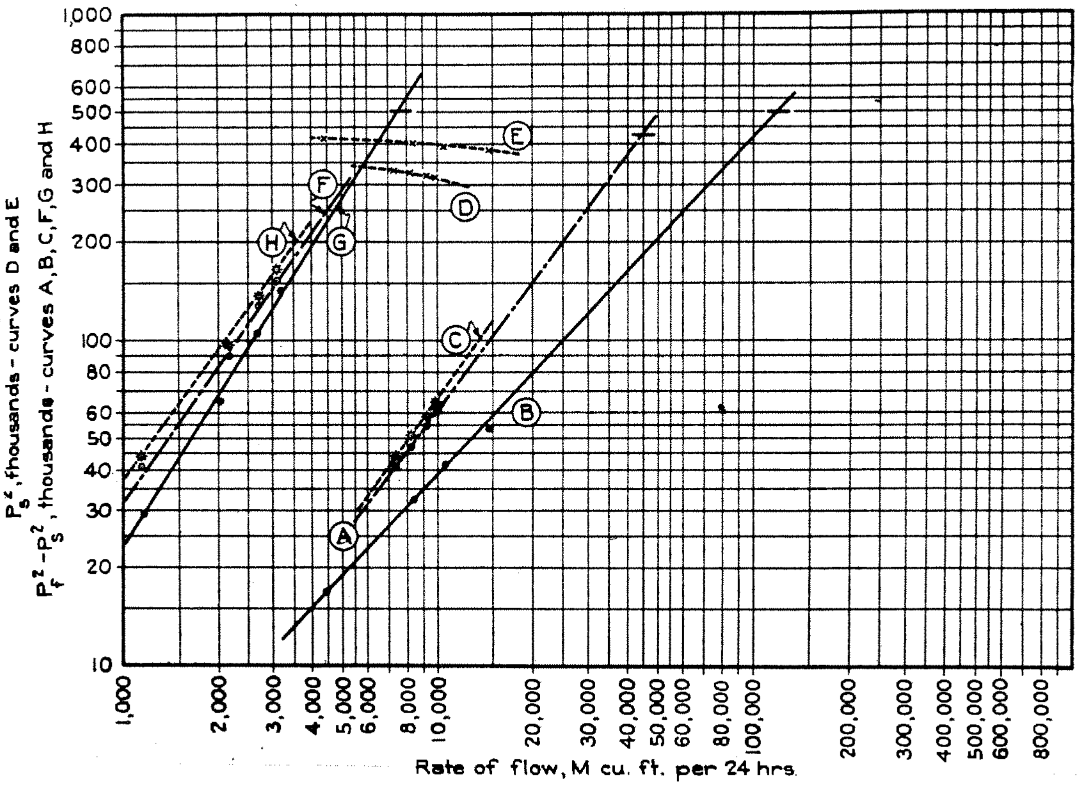
Value of n	Number of back-pressure tests	Value of n	Number of back-pressure tests
Less than 0.5	5	1.2 to 1.4	31
0.5 to 0.6	27	1.4 to 1.6	15
.6 to .7	111	1.6 to 1.8	6
.7 to .8	220	1.8 to 2.0	3
.8 to .9	184	2.0 to 2.5	10
.9 to 1.0	130	2.5 to 3.0	2
1.0 to 1.2	103	Greater than 3	3
			850

The information gained from back-pressure tests can be applied to the solution of such natural-gas production problems as the effect on delivery capacities of liquid in the well bore and in the producing formation, desirability of using tubing, variation in gas availability due to the variation in rate of flow stabilization, rate at which gas should be produced, effect of treating gas wells with acid, effect of shooting, accumulation of cavings in the well bore, and changes in producing characteristics of a well during its producing life.

LIQUID IN WELL BORE AND ADJACENT PRODUCING FORMATION

Liquid in the well bore and in the producing formation may be water, crude oil, " gasoline," and liquefied gases that vaporize when not subjected to the high pressures in the reservoir. The presence of liquid in wells makes it difficult to interpret the results of back-pressure tests properly. It is difficult not only to account for the effect of the liquid on the back-pressure data, but the final calculated data may be in error, and it is impracticable to evaluate the effect of the liquid on gas availability under operating conditions. The results of back-pressure tests on gas wells with liquid in the well bore or on wells that produce liquid with the gas might therefore reflect the effect on the relationship between Q and $P_f^2-P_s^2$ of a combination of the two factors, error in back-pressure data and changes in rate of gas production due to effect of liquid on the permeability of the formation.

The calculated results of a back-pressure test on a gas well with liquid in the well bore are subject to error unless the effect of the liquid is considered when bottom-hole pressures are calculated under shut-in and flowing conditions. Measurement of delivery rates during the back-pressure test also is subject to error if liquid accompanies the gas flowing through the measuring equipment.



A and F, Results of back-pressure tests before open flow of wells, liquid column not considered
C " H, " " " " " " " " " " " , " " considered
B " G, " " " " " after " " " " "
D " E, Squares of well-head pressures corresponding to different delivery rates before and after open flow of well respectively calculated from A and B

FIGURE 7.—Effect of liquid on interpretation of back-pressure data. (Comparison of gas deliveries before and after open flow of wells)

The study of gaging gas-well deliveries showed that the wells affected by the presence of liquid which influenced the back-pressure data and the producing characteristics of the wells can be classified in three distinct divisions:

1. " Wet " or combination oil and gas wells where appreciable quantities of liquid are produced with the gas under all operating conditions.

2. Gas wells subjected to increased accumulation of liquid when operated at relatively low delivery rates or under shut-in conditions but subjected less to liquid accumulation in the well bore when gas is produced at high rates of flow.

3. Gas wells which are little affected by liquid at low delivery rates but which cannot be operated efficiently at higher rates of flow because water enters the drainage area of the well at a rapid rate and restricts the movement of gas to the well bore.

Liquid conditions in gas wells often can be interpreted properly from a carefully conducted series of back-pressure tests, and such an interpretation is important from a standpoint of operation. For example, the information gained from back-pressure tests shows that tubing and siphon installations are not always the best and most economical remedial measures for solving operating problems due to liquid in gas wells and that liquid conditions often can be controlled and regulated better by producing the gas under proper pressure control.

TABLE 7.—*Data and calculations from back-pressure tests of a gas well showing effect of liquid in the well bore*

(Comparison of deliveries before and after open flow of well)[1]

Location of well: Depew field, Okla.
First sand: 3,155 feet; last sand: 3,165 feet.
Size of casing: 8¼-inch.
No tubing.

Date: Dec. 10, 1929.
Total depth: 3,165 feet.
Specific gravity: 0.708.
GL: 2,240.

Back-pressure data

Reading no.	Before open flow of well			After open flow of well		
	Shut-in pressure at wellhead, lb. per sq. in. gage	Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours	Shut-in pressure at wellhead, lb. per sq. in. gage	Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours
	590			640		
1	..	545	9,826	..	602	14,623
2	..	550	9,260	..	612	10,471
3	..	555	8,243	..	618	8,396
4	..	560	7,304	..	628	4,402

Plotting data

Reading no.	Before open flow of well				After open flow of well			
	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours
1	654[2]	606[2]	60.5	9,826	708	669	53.7	14,623
2	..	611	54.4	9,260	..	678	41.6	10,471
3	..	617	47.0	8,243	..	685	32.1	8,396
4	..	622	40.8	7,304	..	696	16.9	4,402
1	704[3]	656[3]	65.3	9,826	..	..	..	..
2	..	661	58.7	9,260	..	..	..	..
3	..	667	50.7	8,243	..	..	..	..
4	..	672	44.0	7,304	..	..	..	..

[1] Curves *A*, *B*, and *C*, fig. 7.
[2] Pressure of liquid column in wells not considered, curve *A*, fig. 7.
[3] Pressure of liquid column in well considered, curve *C*, fig. 7.

The results of two back-pressure tests on a large gas well in the Depew field, Oklahoma, are shown in figure 7, curves *A*, *B*, *C*, *D*, and *E*. The well was " blown " wide open to the atmosphere during the interval between the back-pressure tests. Gas of specific gravity of 0.708 was produced from a depth of approximately 3,165 feet through 8¼-inch casing. The back-pressure data and the results of the calculations of the data are shown in table 7. The first back-pressure test was conducted before any water was removed from the well. The shut-in pressure at the wellhead just before this test was 590 pounds per square inch gage. The second back-pressure test was made after the well had been "blown," and the shut-in pressure at the wellhead after liquid removal was 640 pounds per square inch gage. The "open-flowing" of the well therefore removed a quantity of water from the well bore equivalent to a pressure of 50 pounds per square inch.

Curve *A*, figure 7, shows the results of the back-pressure test made before the well was blown—the calculations being based upon a pressure at the wellhead of 590 pounds per square inch gage and back pressures that were observed at the wellhead—without taking

TABLE 8.—*Data and calculations from back-pressure tests of a gas well, showing effect of liquid in the well bore*

(Comparison of deliveries before and after open flow of well)[1]

Location of well: Depew field, Okla.
First sand: 3,188 feet; last sand: 3,200 feet.
Size of casing: 6⅝-inch.
No tubing.

Date: December, 1929.
Total depth: 3,200 feet.
Specific gravity: 0.700.
GL: 2,235.

Back-pressure data

Reading no.	Before open flow of well: Shut-in pressure at wellhead, lb. per sq. in. gage	Before open flow of well: Working pressure at wellhead, lb. per sq. in. gage	Before open flow of well: Rate of flow, M cu. ft. per 24 hours	After open flow of well: Shut-in pressure at wellhead, lb. per sq. in. gage	After open flow of well: Working pressure at wellhead, lb. per sq. in. gage	After open flow of well: Rate of flow, M cu. ft. per 24 hours
	590			640		
1	..	470	3,103	..	540	3,202
2	..	497	2,704	..	568	2,684
3	..	522	2,173	..	595	2,026
4	..	560	1,119	..	620	1,152

Plotting data

Reading no.	Before: P_f, lb. per sq. in. absolute	Before: P_s, lb. per sq. in. absolute	Before: $P_f^2 - P_s^2$, thousands	Before: Q, M cu. ft. per 24 hours	After: P_f, lb. per sq. in. absolute	After: P_s, lb. per sq. in. absolute	After: $P_f^2 - P_s^2$, thousands	After: Q, M cu. ft. per 24 hours
1	654[2]	525[2]	152.1	3,103	708	600	141.3	3,202
2	..	554	120.8	2,704	..	630	104.4	2,684
3	..	581	90.1	2,173	..	660	65.7	2,026
4	..	622	40.8	1,119	..	687	29.3	1,152
1	704[3]	575[3]	165.0	3,103	..	..	..	..
2	..	604	130.8	2,704	..	..	..	..
3	..	631	97.4	2,173	..	..	..	..
4	..	672	44.0	1,119	..	..	..	..

[1] Curves *F*, *G*, and *H*, fig. 7.
[2] Pressure of liquid column in well not considered, curve *F*, fig. 7.
[3] Pressure of liquid column in well considered, curve *H*, fig. 7.

into consideration any correction for liquid in the well bore. Curve *B* shows the results of the test conducted after the well was blown and gives the delivery capacities of the well at different back pressures under the conditions of the test. Curve *C* was obtained by adding the pressure of 50 pounds per square inch (difference between the shut-in pressure for the two tests) to the shut-in formation pressure and to each of the back pressures at the sand as calculated for curve *A*. Comparison of curves *A*, *B*, and *C* shows that if the pressure of the column of liquid in this well is not taken into consideration the presence of the liquid not only causes erroneous conclusions but decreases the capacity of the well to deliver gas. This is illustrated further by curves *D* and *E*, which represent the relationship between rate of flow and square of the back pressure at the wellhead. For example, after the well had been blown, 10,000,000 cubic feet of gas per 24 hours could be produced with a wellhead pressure of 629 pounds per square inch absolute (curve *E*) whereas before any of the liquid had been removed the well could not produce at that rate unless the wellhead pressure were reduced to 557 pounds per square inch absolute (curve *D*).

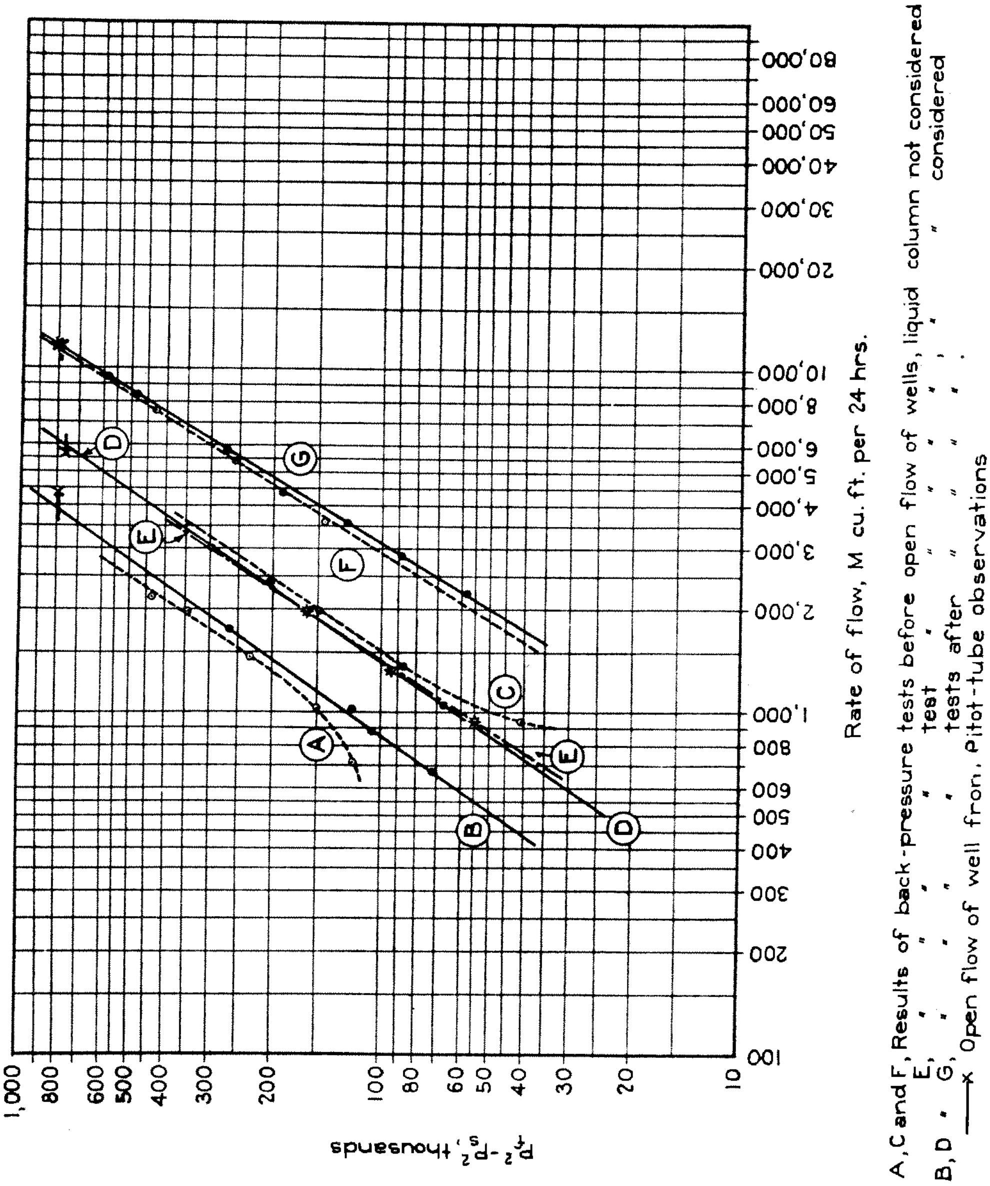


FIGURE 8.—Effect of liquid on interpretation of back-pressure data. (Comparison of gas deliveries before and after open flow of wells)

Curves *F*, *G*, and *H* (fig. 7) show results obtained from back-pressure tests on a low-volume gas well in the Depew field, Oklahoma, the data and calculations for which are given in table 8. The presence of liquid in the well bore equivalent to a pressure of 50 pounds per square inch did not have as much effect on the capacity of the well to deliver gas as on that of the well previously discussed and defined by curves *A*, *B*, and *C*.

The results of back-pressure tests on three representative gas wells in the Galva field, McPherson County, Kans., are shown in figure 8. The gas-producing formation, known locally as the "chat," is at a depth of about 2,900 feet below the surface of the ground and approximately 1,350 feet below sea level. The majority of the wells in the Galva field were completed with 8¼-inch casing, which was cemented in the top of the producing zone. The shut-in pressures of the different wells throughout the field are uniform.

A back-pressure test was made on each well before it was "blown" or cleaned of accumulations of liquid. After the back-pressure test had been made the well was opened wide to the atmosphere for 15 minutes, and the open flow was gaged with a

TABLE 9.—*Data and calculations from back-pressure tests of a gas well, showing effect of liquid in well bore*

(Comparison of deliveries before and after open flow of well)[1]

Location of well: Galva field, Kans.
First sand: 2,895 feet; last sand: 2,928 feet.
Size of casing: 8¼-inch; set at: 2,885 feet.
No tubing.

Date: April 4, 1932.
Total depth: 2,928 feet.
Producing formation: Chat.
GL: 1,995.
Specific gravity: 0.685.

Back-pressure data

Reading no.	Before open flow of well			After open flow of well		
	Shut-in pressure at wellhead, lb. per sq. in. gage	Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours	Shut-in pressure at wellhead, lb. per sq. in. gage	Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours
	813			814		
1	..	749	708	..	661	1,467
2	..	546	2,170	..	756	885
3	..	609	1,980	..	748	1,023
4	..	683	1,442	..	776	672
5	..	731	1,027	..	..	..

Plotting data

Reading no.	Before open flow of well				After open flow of well			
	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours
1	888	818	119.4	708	888	724	264.3	1,467
2	..	596	433.3	2,170	..	826	106.2	885
3	..	668	342.3	1,980	..	817	121.0	1,023
4	..	747	230.5	1,442	..	847	71.1	672
5	..	799	150.1	1,027	..	..	..	..

[1] Curves *A* and *B*, fig. 8.

Pitot tube. A second back-pressure test then was made to obtain data for comparing the delivery capacities of the wells before and after "blowing."

The data and calculations for the back-pressure tests on one well, illustrated by curves *A* and *B* (fig. 8), are shown in table 9. The shut-in pressures before and after the open flow of the well were virtually the same, indicating that there was no change in liquid level in the well bore due to open flow. A comparison of curves *A* and *B*, which illustrate graphically the results of the back-pressure tests before and after the open flow of the well, shows an appreciable variation in the delivery capacities of the well under the two conditions, especially at the low rates of flow corresponding to high back pressures. Also, curve *B* represents a more efficient producing characteristic of the well. The variation in the delivery capacities before and after open-flowing probably was caused by a change in the liquid condition in the drainage space surrounding the well rather than by liquid in the well bore.

The data and calculations for back-pressure tests on another well in the Galva field, illustrated by curves *C, D,* and *E* (fig. 8), are shown in table 10. The shut-in pressure at the wellhead was 746 pounds per square inch gage before and 807 pounds per square inch

TABLE 10.—*Data and calculations from back-pressure tests of a gas well, showing effect of liquid in the well bore*

(Comparison of deliveries before and after open flow of well)[1]

Location of well: Galva field, Kans.
First sand: 2,910 feet; last sand: 2,923 feet.
Size of casing: 8¼-inch; set at: 2,907 feet.
No tubing.

Date: April 6, 1932.
Total depth: 2,923 feet.
Producing formation: Chat.
Specific gravity: 0.677.
GL: 1,970.

Back-pressure data

Reading no.	Before open flow of well			After open flow of well		
	Shut-in pressure at wellhead, lb. per sq. in. gage	Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours	Shut-in pressure at wellhead, lb. per sq. in. gage	Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours
	746			807		
1	..	650	1,986	..	628	3,000
2	..	690	1,376	..	690	2,400
3	..	712	942	..	755	1,394
4	..	..	..	..	772	1,050
5	..	..	..	..	788	538

Plotting data

Reading no.	Before open flow of well				After open flow of well			
	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours
1	810[2]	712[2]	149.2	1,986	880	689	299.7	3,000
2	..	754	87.6	1,376	..	754	205.9	2,400
3	..	778	40.8	942	..	825	93.8	1,394
4	..	..	..	..	..	841	67.1	1,050
5	..	..	..	..	..	..	..	..
1	871[3]	773[3]	161.1	1,986	..	..	..	..
2	..	815	94.4	1,376	..	..	..	..
3	..	839	54.7	942	..	..	..	..

[1] Curves *C, D,* and *E*, fig. 8.
[2] Pressures of liquid column in well not considered, curve *C*, fig. 8.
[3] Pressure of liquid column in well considered, curve *E*, fig. 8.

gage after the open flow of the well. Blowing, therefore, caused a change in the column of liquid in the well bore equivalent to a pressure difference of 61 pounds per square inch. Curve *C* is based on back-pressure data obtained before the open flow of the well, without considering the effect of liquid in the well bore on pressures, and curve *D* is based on back-pressure data after the open flow of the well. The data from which curve *C* was plotted then were corrected for the pressure of 61 pounds per square inch exerted by the column of liquid, as shown in table 10; and these corrected data were used to determine curve *E*, which coincides practically with curve *D*. The back-pressure data indicate that for this particular well liquid in the well bore would cause some error in the calculations if it were not considered; however, the liquid did not decrease the delivery capacity of the well based on pressures at the sand face, although it reduced pressure at the wellhead corresponding to any given delivery.

The data and calculations for the back-pressure tests on a third well in the Galva field, illustrated by curves *F* and *G* (fig. 8) are

TABLE 11.—*Data and calculations from back-pressure tests of a gas well, showing effect of liquid in the well bore*

(Comparison of delivery rates before and after open flow of wells)[1]

Location of well: Galva field, Kans.
First sand: 2,892 feet; last sand: 2,915 feet.
Size of casing: 6⅝-inch; set at: 2,887 feet.
Liner: 305 feet of 5-3/16-inch. Tools in hole.
No tubing.

Date: March 30, 1932.
Total depth: 2,915 feet.
Producing formation: Chat.
GL: 1,985.
Specific gravity: 0.683.

Back-pressure data

Reading no.	Before open flow of well			After open flow of well		
	Shut-in pressure at wellhead, lb. per sq. in. gage	Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours	Shut-in pressure at wellhead, lb. per sq. in. gage	Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours
	815			819		
1	..	736	3,590	..	423	9,400
2	..	543	7,650	..	509	8,420
3	..	667	5,410	..	663	5,800
4	..	709	4,390	..	751	3,545
5	..	..	..	..	771	2,880
6	..	..	..	..	788	2,220

Plotting data

Reading no.	Before open flow of well				After open flow of well			
	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours
1	889[2]	804[2]	143.9	3,590	893	476	570.8	9,400
2	..	599	431.5	7,650	..	563	480.5	8,420
3	..	730	257.4	5,410	..	726	270.3	5,800
4	..	775	190.2	4,390	..	820	125.0	3,545
5	..	..	..	..	..	842	88.4	2,880
6	..	..	..	..	..	860	57.8	2,220
1	893[3]	808[3]	134.5	3,590	..	..	..	..
2	..	603	433.8	7,650	..	..	..	..
3	..	734	258.6	5,410	..	..	..	..
4	..	779	190.6	4,390	..	..	..	..

[1] Curves *F* and *G*, fig. 8.
[2] Pressure of liquid column in well bore not considered, curve *F*, fig. 8.
[3] Pressure of liquid column in well bore considered, not shown in fig. 8.

shown in table 11. The difference between the shut-in pressures at the wellhead before and after the open flow is only 4 pounds per square inch. Curve *F* is based on back-pressure data obtained before the open flow of the well, without considering the effect of liquid in the well bore on pressures, and curve *G* is based on back-pressure data obtained after open flow. Correcting the back-pressure data for the pressure of 4 pounds per square inch exerted by the column of liquid in the well bore shows that the liquid had a negligible effect on the producing characteristic of the well. Therefore, it may be concluded that the small difference between curves *F* and *G* probably is caused by liquid in the drainage space surrounding the well.

The open-flow volumes of the wells (fig. 8) were gaged with a Pitot tube at the end of a 15-minute " blow-down " period. The open-flow volume of one well (curves *A* and *B*, fig. 8) also was gaged after a 20-minute " blow-down " period, and the results indicated that the flow stabilized slowly. Impact pressures were observed at

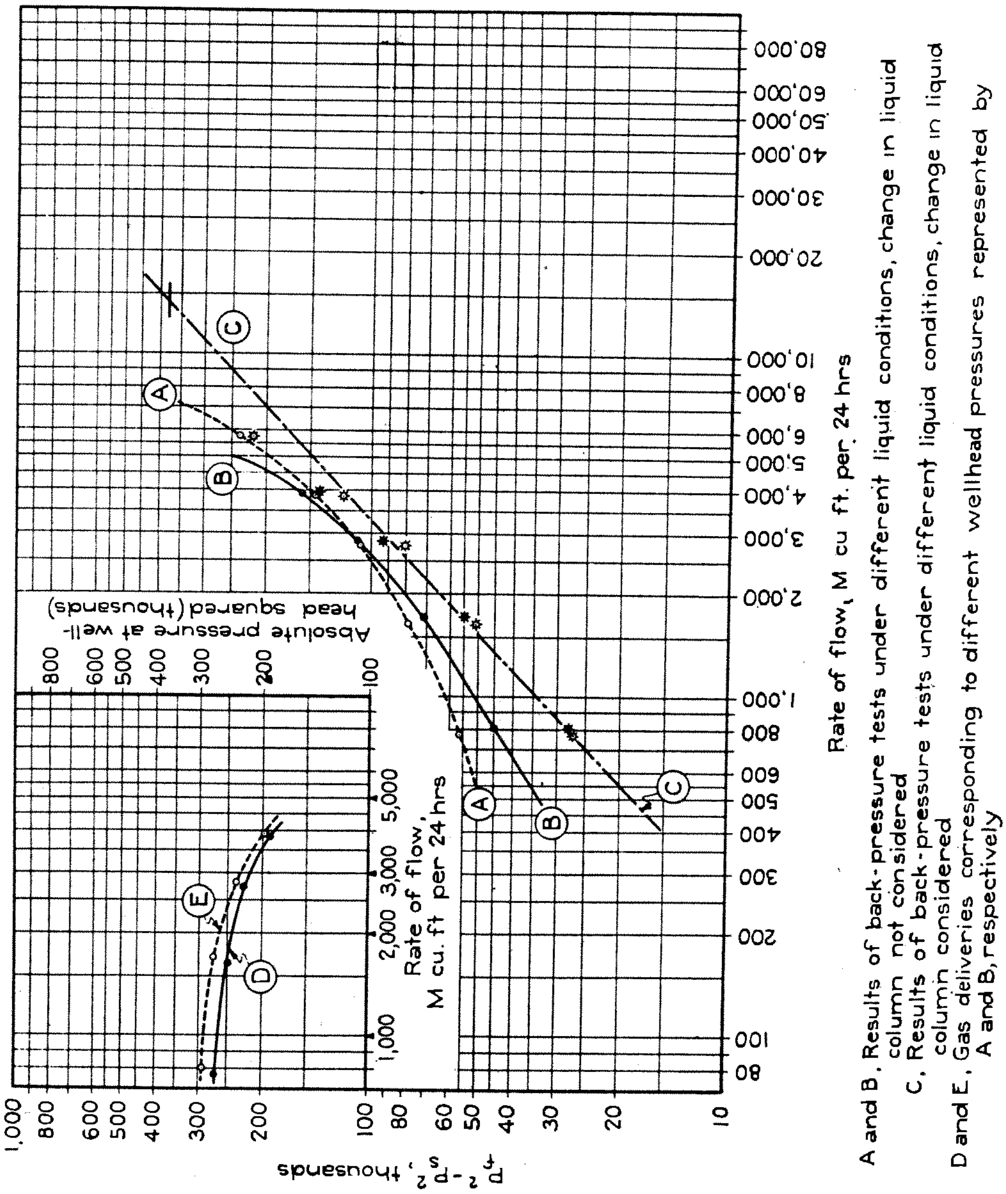


FIGURE 9.—Effect of liquid on interpretation of back-pressure data. (Comparison of gas deliveries under different liquid conditions in well bore)

different points in the plane of the discharge opening of the pipe, and volumes calculated from observations at the different locations [31] were erratic, probably due to unequal distribution of entrained liquid in the plane of the opening. The erratic results emphasize the possibility of error in measurement of open flows with Pitot tubes on certain types of well.

Back-pressure tests conducted by the authors in the Refugio field in southern Texas emphasize the difficulty of obtaining satisfactory

[31] See appendix 4.

data on gas deliveries from certain wells in which liquid accumulates. The thickness of the formation from which the wells produce ranges from 3 to 26 feet, and most of the wells are completed with 8¼-inch casing.

The results of two back-pressure tests on one of the representative wells in the field and one interpretation of the assembled back-

TABLE 12.—*Data and calculations from back-pressure tests of gas wells, showing effect of liquid in the well bore*

(Comparison of delivery rates under different liquid conditions)[1]

Location of well: Refugio field, Tex.
First sand: 3,278 feet; last sand: 3,281 feet.
Size of casing: 8¼-inch.
Producing through 8¼-inch casing.
No tubing.

Date: Sept. 16 and 17, 1933.
Total depth: 3,283 feet.
Specific gravity: 0.56.
GL: 1,840.

Back-pressure data

Test A					Test B				
Reading no.	Shut-in pressure at wellhead, lb. per sq. in. gage		Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours	Reading no.	Shut-in pressure at wellhead, lb. per sq. in. gage		Working pressure at wellhead, lb. per sq. in. gage	Rate of flow, M cu. ft. per 24 hours
	Before test	After test				Before test	After test		
	550					563			
1	..	..	315	5,740	1	..	..	427	3,920
2	..	..	422	3,890	2	..	..	473	2,860
3	..	..	459	2,780	3	..	..	506	1,705
4	..	..	484	1,638	4	..	..	528	805
5	..	..	504	773			548		
		524							

Plotting data

Test A					Test B				
Reading no.	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours	Reading no.	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$ thousands	Q, M cu. ft. per 24 hours
1[2]	600	350	238.0	5,740	1[3]	614	469	157.0	3,920
2	..	464	145.0	3,890	2	..	518	109.0	2,860
3	..	503	107.0	2,780	3	..	553	71.0	1,705
4	..	530	79.0	1,638	4	..	576	45.0	805
5	..	551	56.0	773					
1[4]	600	376	218.6	5,740	1[4]	614	484	142.7	3,920
2	..	490	119.9	3,890	2	..	533	92.9	2,860
3	..	529	80.2	2,780	3	..	568	54.4	1,705
4	..	556	50.9	1,638	4	..	591	27.7	805
5	..	577	27.1	773					

[1] Curves *A*, *B*, and *C*, fig. 9.
[2] Curve *A*, fig. 9.
[3] Curve *B*, fig. 9.
[4] Curve *C*, fig. 9.

pressure data are shown in figure 9. The data and calculations applicable to the well are given in table 12.

The shut-in pressure at the wellhead before liquid was removed from the well bore was 478 pounds per square inch gage. The well then was allowed to produce through a 1¼-inch orifice at the wellhead, and the velocity of the flow was sufficient to lift liquid from the well bore. The well was allowed to flow for a time but the quantity of liquid produced did not diminish apparently, and the well was "shut in." Subsequently, the shut-in pressure at the wellhead was 550 pounds per square inch gage, indicating a removal of liquid from the well bore equivalent to a pressure of 72 pounds per square inch. Curve *A* (fig. 9) shows the results of the back-pressure test made without considering the effect on pressures of change in the liquid condition in the well bore, the data and calculations being designated by test *A* in table 12. The data show a decrease in the shut-in wellhead pressure of 550 to 524 pounds per square inch during the back-pressure test, or an increase in the liquid column equivalent to 26 pounds per square inch. Stabilized pressure and flow conditions were not obtained for the first set of observations in test *A*, where a working pressure at the wellhead of 315 pounds per square inch gage and a delivery rate of 5,740,000 cubic feet of gas per 24 hours were recorded. Under these operating conditions liquid was produced with the gas from the well at a rate that did not diminish. At the other rates of flow of the test series the gas apparently was free from entrained liquid.

The well then was shut in over night, and on the following morning the shut-in pressure at the wellhead was 526 pounds per square inch gage or virtually the same as that observed immediately after the first back-pressure test. The well then was allowed to produce through a 1-inch orifice, and the velocity of flow was sufficient to remove liquid from the well. The quantity of liquid produced with the gas did not diminish, and the well was shut in, the shut-in pressure being 563 pounds per square inch gage. A second back-pressure test (test *B*, table 12) was conducted, and curve *B* (fig. 9) shows the results of calculations based on the shut-in pressure observed at the beginning of the test, without considering the effect on pressures of the change in the liquid condition in the well bore. The data show a decrease in the shut-in wellhead pressures from 563 to 548 pounds per square inch gage, or a change in the liquid column equivalent to 15 pounds per square inch. The data obtained in tests *A* and *B* were recalculated, and changes in the liquid column of 26 pounds per square inch for test *A* and 15 pounds per square inch for test *B* were taken into consideration. It was assumed for purposes of calculation that the change in the liquid column occurred during the initial high rate of flow in each test, and accordingly each of the computed back pressures at the face of the sand in test *A* was increased by 26 pounds per square inch and in test *B* by 15 pounds per square inch. The calculations for each test were based on the shut-in pressure observed before the test and the plotted points are fairly consistent along curve *C* (fig. 9), especially for gas flows at high back pressures.

The location of the plotted points along curve *C* indicates that the different liquid conditions in the well bore during the two tests had negligible effects on the delivery capacity of the well at similar back pressures at the sand corresponding to low rates of flow but that at higher rates of flow delivery capacities were affected appreciably by liquid in the well. Curve *C* indicates a consistent agreement in the relationships between Q and $P_f^2 - P_s^2$ for the two liquid conditions with delivery rates less than 2,500,000 cubic feet of gas per 24 hours and a small variation between the relationships with delivery rates greater than 2,500,000 cubic feet per 24 hours. However, the relationships between the rate of production and the pressure at the wellhead, which are factors of importance in operating wells, are different throughout the range of flow rates and pressures, as shown by curves *D* and *E*. For instance, a delivery rate of 2,000,000 cubic feet of gas per 24 hours could be obtained with a back pressure at the wellhead of 514 pounds per square inch absolute under the conditions of test *B* compared with 492 pounds per square inch absolute under the conditions of test *A*.

The results of back-pressure tests on two representative gas wells in the Agua Dulce field in southern Texas are shown in figures 10 and 11. The wells in this field produce from a relatively thin horizon

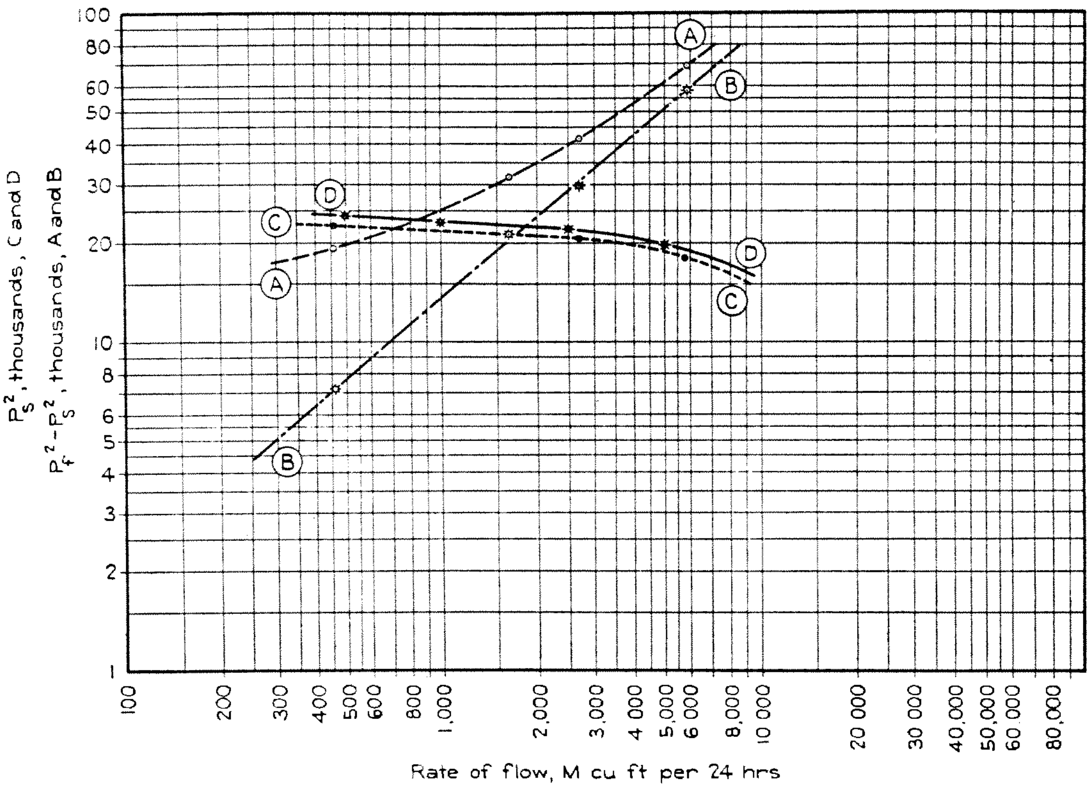


FIGURE 10.—Effect of liquid on interpretation of back-pressure data. (Comparison of interpretations based on shut-in pressures before and after back-pressure tests)

at a depth of approximately 1,980 feet and are completed with 6- or $6\frac{5}{8}$-inch casing and 2-inch tubing. The gas carried entrained liquid and solids, especially at high rates of flow, and it is difficult to produce gas from the wells under operating conditions and to conduct back-pressure tests on them. Even under the flow conditions of the back-pressure tests, enough solids were produced during high rates of flow to damage wellhead fittings and critical-flow-meter equipment. Because the solids were exceedingly abrasive the orifices in the thin plates of soft steel that were part of the authors' equipment could not be used for measuring and controlling the flow, so choke nipples [32] were used in the back-pressure tests.

[32] See appendix 3.

The mixture of liquid and solids did not act as a fluid, as was indicated by the unequalized pressures gaged on the tubing and casing before and after the wells were "blown" through the tubing and before and after the back-pressure tests. The wells were blown through the tubing before the back-pressure tests, and the flows were regulated with a 1½-inch choke nipple, but the quantity of liquid and solids entrained in the flows apparently did not diminish. It was noticed, however, that gas could be produced from the wells at low delivery rates with only small quantities of liquid and solids in the flow stream.

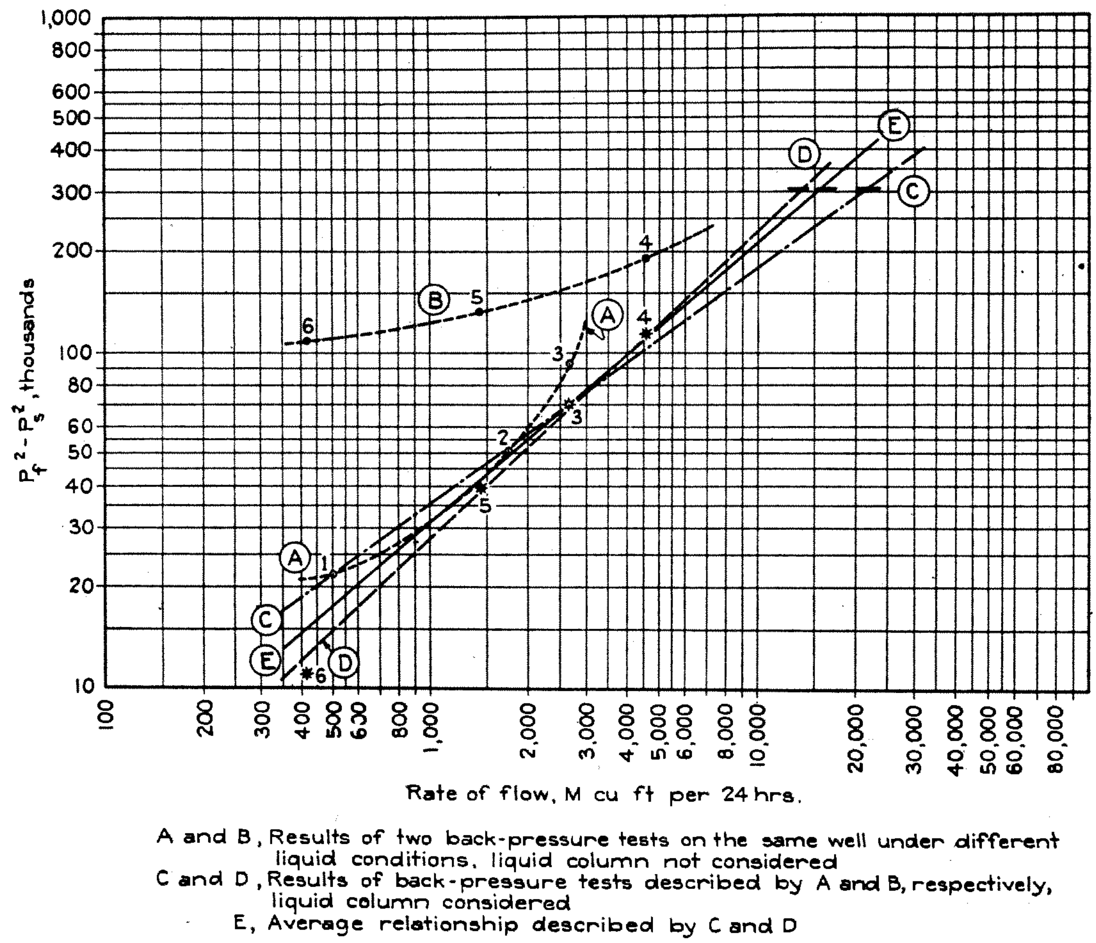


FIGURE 11.—Effect of liquid on interpretation of back-pressure data. (Comparison of gas deliveries with variation in sequence of pressure-flow data)

The results of the back-pressure tests on one of the wells in the Agua Dulce field are given in figure 10. The well is 1,974 feet deep and was completed with 6-inch casing and equipped with 2-inch tubing. The gas deliveries during the back-pressure test were made through the annular space between the tubing and the 6-inch casing. The back-pressure data and calculations for the test are shown in table 13. The shut-in tubing and casing pressures before the back-pressure test were 481 and 480 pounds per square inch gage, respectively, and 469 pounds per square inch gage on each of the strings after the test. The data indicate an increase in the height of the column of liquid in the tubing during the test equivalent to a pressure of 12 pounds per square inch. Curve *A* (fig. 10) is based on the shut-in pressure before the test and the observed back-pressure data without considering the effect on pressures of liquid in the well. The data used to plot the points for curve *B* were obtained by using the shut-in pressure before the test and adding 12 pounds per square inch to each of the back pressures at the sand as calculated for curve *A*, assuming that the change in the liquid column occurred during the initial and maximum flow of the test series. Curves *C* and *D* were

TABLE 13.—*Data and calculations from back-pressure tests of a gas well, showing effect of liquid in the well bore*

(Comparison of results based on observations of shut-in pressures before and after back-pressure tests)[1]

Location of well: Agua Dulce field, south Tex.
First sand: 1,964 feet; last sand: 1,974.
Size of casing: 6-inch; set at: 1,969 feet.
Size of tubing: 2-inch.
Producing through casing.

Date: Sept. 20, 1932.
Total depth: 1,974 feet.
Specific gravity: 0.57.
GL: 1,120.

Back-pressure data

Reading no.	Shut-in pressure at wellhead, lb. per sq. in. gage				Working pressure at wellhead, lb. per sq. in. gage		Rate of flow, M cu. ft. per 24 hours
	On tubing		On casing		On tubing	On casing	
	Before test	After test	Before test	After test			
	481		480				
1	..	..	..	..	411	409	5,850
2	..	..	..	..	440	439	2,700
3	..	..	..	..	449	445	1,625
4	..	..	..	..	462	457	457
		469		469			

Plotting data

Reading no.	Liquid in well bore not considered[2]				Liquid in well bore considered[3]			
	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours
1	514	442	68.8	5,850	514	454	58.1	5,850
2	..	472	41.4	2,700	..	484	29.9	2,700
3	..	481	31.9	1,625	..	493	21.2	1,625
4	..	495	19.2	457	..	507	7.2	457

[1] Curves in fig. 10.
[2] Curves *A* and *C*, fig. 10.
[3] Curves *B* and *D*, fig. 10.

obtained by plotting delivery rates against the squares of the corresponding pressures at the wellhead. Curve *C* shows the delivery rates corresponding to the squares of different wellhead pressures obtained during the back-pressure test, and curve *D* shows the squares of the relatively higher back pressures that would have existed at the same delivery rates if the column of liquid in the well had not increased under flowing conditions.

The results of a back-pressure test conducted on another gas well in the Agua Dulce field are shown in figure 11. The data and calculations are given in table 14. The well is 1,986 feet deep and was completed with 6⅝-inch casing and equipped with 2-inch tubing. The gas deliveries during the back-pressure test were made through the 6⅝-inch casing. The stabilized shut-in pressure at the wellhead after the well was blown through the tubing was 468 pounds per square inch gage on the tubing and 520 pounds per square inch gage on the casing. Three observations of delivery rates at different back pressures were made; the lower rates of flow in the test series were observed first. The well then was shut in again, and a pressure of 380 pounds per square inch gage on the tubing and 496 pounds per square inch gage on the casing was registered at the wellhead, indicating increases in the liquid columns in the tubing and casing equivalent to 88 pounds per square inch

TABLE 14.—*Data and calculations from a back-pressure test of a gas well, showing effect of liquid in the well bore*

(Comparison of deliveries with variation in sequence of pressure-flow data)[1]

Location of well: Agua Dulce field, south Tex.
First sand: 1,983 feet; last sand: 1,986 feet.
Size of casing: 6⅝-inch.
Size of tubing: 2-inch.
Producing through casing.

Date: Sept. 22, 1932.
Total depth: 1,986 feet.
Specific gravity: 0.57.
GL: 1,130.

Back-pressure data

Reading no.	Shut-in pressure at wellhead, lb. per sq. in. gage				Working pressure at wellhead, lb. per sq. in. gage		Rate of flow, M cu. ft. per 24 hours
	On tubing		On casing		On tubing	On casing	
	Before test	After test	Before test	After test			
	468		520				
1	..	..	..	..	459	501	500
2	..	..	..	..	387	474	1,730
3	..	..	..	..	347	432	2,660
Shut in	..	..	..	..	380	496	Shut in
4	..	..	..	..	318	314	4,530
5	..	..	..	..	393	390	1,430
6	..	..	..	..	369	416	417
		348		422			

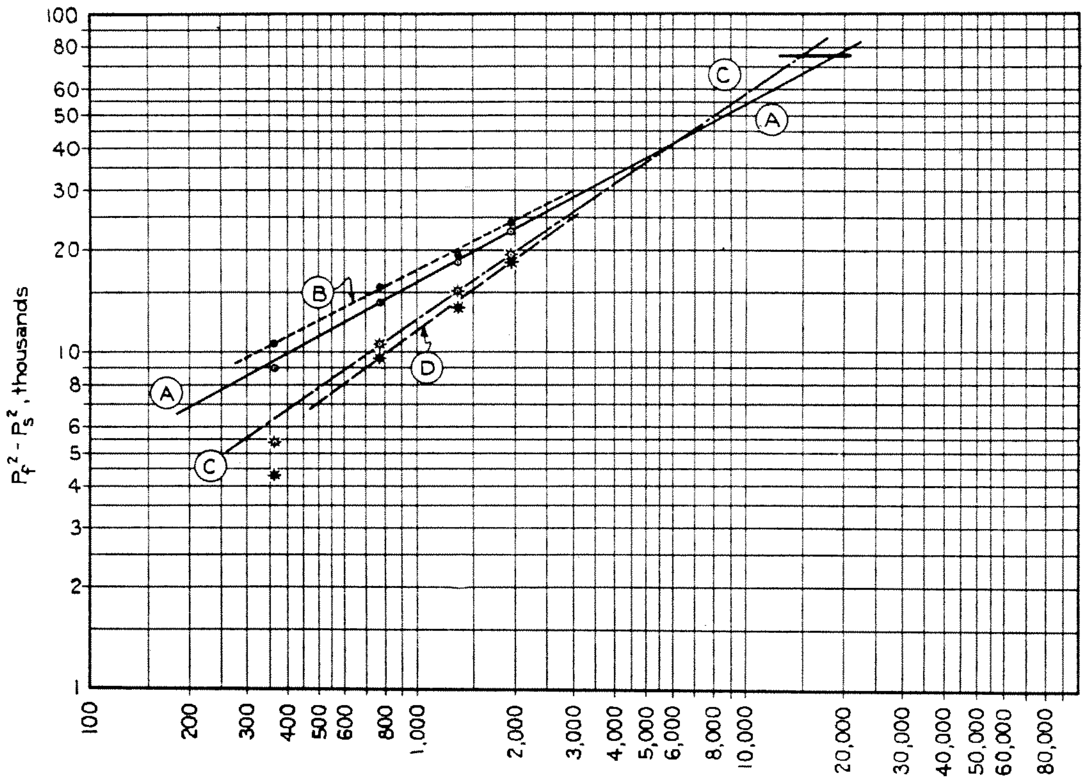
Plotting data

Reading no.	Liquid in well bore not considered[2]				Liquid in well bore considered[3]			
	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours
1	555	535	21.8	500	555	535	21.8	500
2	..	508	50.9	1,730	..	508	50.9	1,730
3	..	464	92.7	2,660	..	488	69.9	2,660
4	..	342	191.3	4,530	..	440	114.4	4,530
5	..	420	131.6	1,430	..	518	39.7	1,430
6	..	447	108.2	417	..	545	11.0	417

[1] Curves of fig. 11.
[2] Curves *A* and *B*, fig. 11.
[3] Curves *C* and *D*, fig. 11.

and 24 pounds per square inch, respectively. Three additional back-pressure observations were made, the high rates of flow in the test series being measured first. The shut-in pressure on the tubing at the wellhead after the back-pressure test was 348 pounds per square inch gage and on the casing 422 pounds per square inch gage. The total increases in the liquid columns in the tubing and casing therefore were equivalent to 120 and 98 pounds per square inch, respectively.

Curve *A* (fig. 11) is based on the observed shut-in wellhead pressure on the casing before the back-pressure test and on the back pressures of the first three observations, without considering the effect on pressures of change in the liquid column in the well bore. Curve *B* is based on the same shut-in pressure as curve *A* and on the back pressures of the last three observations, also without considering the effect on pressures of change in the liquid column in the well bore. Later, the effect of change in the liquid column in the well bore was considered in calculating the back-pressure data. Because the first and second observations were made under conditions of low rates of flow it was assumed that there was no change in the height of the liquid column during these flows. The third observa-



A and B, Back pressures gaged on tubing and casing, respectively, liquid column not considered
C and D, Back pressures gaged on tubing and casing, respectively, liquid column considered

FIGURE 12.—Effect of liquid on interpretation of back-pressure data. (Comparison of interpretations based on pressure observations on casing and tubing)

tion was made under conditions of a relatively high rate of flow, and it was assumed that the change of 24 pounds per square inch in the liquid column (difference of shut-in casing pressures) occurred during the stabilization of pressure and flow conditions. Accordingly, the back pressure was corrected for the 24-pound pressure difference. The result of the analysis of the liquid conditions in the well is shown by curve *C*. The fourth observation of back pressures was made under conditions of a high rate of flow, and the fifth and sixth observations were under conditions of low rates of flow. Accordingly, it was assumed that the increase in the liquid column equivalent to a pressure of 74 pounds per square inch, (difference of shut-in pressures on the casing) occurred during the stabilization of pressure and flow conditions before the fourth observation and that no further change in the liquid column occurred during the fifth and sixth observations. The total correction to be made to each of the back pressures for the fourth, fifth, and sixth observations was 98 pounds per square inch (difference of shut-in pressures on casing before and after test), and curve *D* shows the

TABLE 15.—*Data and calculations from a back-pressure test of a gas well, showing effect of liquid in the well bore*

(Comparison of data obtained on casing and tubing)[1]

Location of well: South Cole field, south Tex.
First sand: 1,704 feet; last sand: 1,709 feet.
Size of casing: 6⅝-inch; set at: 1,704 feet.
Size of tubing: 2-inch.
Producing through casing.

Date: Sept. 26, 1932.
Total depth: 1,709 feet.
Specific gravity 0.57.
GL: 975.

Back-pressure data

Reading no.	Shut-in pressure at wellhead, lb. per sq. in. gage				Working pressure at wellhead, lb. per sq. in. gage		Rate of flow, M cu. ft. per 24 hours
	On tubing		On casing		On tubing	On casing	
	Before test	After test	Before test	After test			
	247		252				
1	..	..	..	..	208	205	1,950
2	..	..	..	..	217	215	1,345
3	..	..	..	..	225	222	772
4	..	..	..	..	235	232	364
		240		240			

Plotting data

Reading no.	Based on tubing back pressures				Based on casing back pressures			
	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours
	Effect of liquid not considered.[2]				Effect of liquid not considered.[4]			
1	275	230	22.7	1,950	275	227	24.1	1,950
2	..	239	18.5	1,345	..	237	19.4	1,345
3	..	248	14.1	772	..	245	15.6	772
4	..	258	9.0	364	..	255	10.6	364
	Effect of liquid considered.[3]				Effect of liquid considered.[5]			
1	275	237	19.4	1,950	275	239	18.5	1,950
2	..	246	15.1	1,345	..	249	13.6	1,345
3	..	255	10.6	772	..	257	9.6	772
4	..	265	5.4	364	..	267	4.3	364

[1] Curves of fig. 12.
[2] Curve *A*, fig. 12.
[3] Curve *C*, fig. 12.
[4] Curve *B*, fig. 12.
[5] Curve *D*, fig. 12.

results of correcting the last three observations. That these data represent a fairly consistent relationship is shown by curve *E*.

The results of a back-pressure test on a gas well in the South Cole field, south Texas, are shown in figure 12. The test is discussed mainly to emphasize the comparison of data obtained on the casing and on the tubing. The observed data and subsequent calculations are given in table 15. During the back-pressure test the well was producing through the casing. The shut-in presures at the wellhead on the tubing and casing before the test were 247 and 252 pounds per square inch gage, respectively, and 240 pounds per square inch gage on both the tubing and casing after the test. There was therefore an increase in the liquid column in the tubing equivalent to a pressure of 7 pounds per square inch, and in the casing equivalent to 12 pounds per square inch. Curve *A* is based on the shut-in pressure on the casing before the back-pressure test and the back pressures gaged on the tubing without taking into consideration the effect on pressures of an increase in the liquid column. Curve *B* is based on the shut-in pressure on the casing before the back-pressure test and on back pressures gaged on the casing, without considering the effect of an increase in the liquid column. Curve *C* was obtained by correcting back pressures on the tubing by a pressure of 7 pounds per square inch, and in curve *D* the back pressures on the casing were corrected for a pressure of 12 pounds per square inch.

If there is liquid in the well bore or the producing formation around it, the ability of the formation to deliver gas within the effective drainage space of the well cannot be interpreted properly from the results of a single back-pressure test of the kind usually made on normal gas wells. The responsiveness of the liquid condition in the formation to changes in pressures and velocities and the effect of unaccounted-for vapor which may be in the well bore on the determination of bottom-hole pressures cannot be determined from a limited number of back-pressure data. The examples given in this report of a number of back-pressure tests conducted on gas wells affected by liquid show the advisability of obtaining as many data during a series of back-pressure tests as possible. Obtaining flow and pressure data for different liquid conditions in the well, frequent observations of shut-in pressures, observations of the well-head pressures during periods of stabilization, changing the sequence of pressure-flow conditions to which wells are subjected during back-pressure tests, and taking more observations than usually are made during back-pressure tests on normal gas wells are necessary for a complete study of the behavior of a gas well affected by liquid. The producing characteristics of gas wells differ, depending upon the type of well and liquid condition, and often wells in the same field have widely different flow characteristics.

The amount of liquid entering some gas wells daily is small, and the liquid does not present a serious operating problem. Usually an occasional blowing of the wells will prevent the liquid from accumulating enough to affect the flow of gas into the well bore. Tubing and siphons generally are used to remove liquid from gas wells. Back-pressure tests on gas wells affected by liquid are more conclusive if the liquids are removed before the back-pressure test is made, but it should be remembered that comparative back-pressure data obtained before and after the removal of liquid are exceedingly helpful in studying the producing characteristics of wells.

Although the rate of liquid entry into many wells is slow the presence of liquid in the drainage spaces of the producing horizon affects the capacity of the well to deliver gas. The high hydrocarbon constituents often are liquids under the pressure and temperature conditions existing in the reservoir, and gas wells frequently are affected mainly by the liquid conditions in the reservoir, since the liquids vaporize in the flow string and are gases at the wellhead. Several back-pressure tests are necessary for thorough study of the behavior of a gas well affected by the presence of liquefied hydrocarbon gases in the reservoir and in the well bore.

Many of the gas wells tested by the back-pressure method of gaging gas-well deliveries have been characterized by rapid entry of liquid into the well bore, due to normal edge-water encroachment, to the entrance of bottom water as a result of " coning " of the water in the sands, or to too deep drilling of the wells. Subjecting gas wells to frequent excessive delivery rates (such as open flow) often causes coning of the water in the producing sand. Although it often is possible to remove liquid that has accumulated in the well bore before a back-pressure test and to conduct the test before liquid again accumulates in appreciable quantities, the results of such a test do not indicate the ability of the well to produce gas under normal operating conditions, and a comparison of the results of back-pressure tests before and after removal of liquid is needed for a proper interpretation of the flowing characteristics of the well. Furthermore, in some wells it is possible to remove only part of the liquid from the well bore, and liquid accumulates again during the back-pressure test, so that operation of gas wells producing large quantities of liquids and solids, especially when the solids are abrasive, is dangerous if the rates of flow are high. In many wells it is impracticable to remove all of the liquid accumulation from the well bore at low and safe rates of flow. On the other hand, unless one has a definite idea of the amount of liquid in the well bore the producing characteristic throughout a range of high deliveries cannot be interpreted properly from data observed under low delivery conditions.

A series of back-pressure tests and proper interpretation of the observed data therefore are needed instead of the single back-pressure test usually conducted on a normal gas well not affected by liquid. Proper interpretation of the observed data will depend on thorough understanding of the conditions in the field in which the well is located and of the well itself, as illustrated by a back-pressure test on a well in the Refugio field in south Texas (fig. 9 and table 12). Assume that curve *C* of figure 9 is representative of the deliveries of gas from the well at different back pressures under the conditions of a shut-in pressure at the wellhead of 563 pounds per square inch gage. Assume further that interpretation of the back-pressure data has eliminated the influence of a change in the liquid column in the well during the period of the back-pressure test and an understanding of the conditions in the field leads to the suspicion that there is a column of liquid in the well bore equivalent to a pressure of 50 pounds per square inch when the shut-in pressure at the wellhead is 563 pounds per square inch gage. The shut-in formation pressure then would be 664 pounds per square inch absolute.

From curve *C* of figure 9 the values of the back pressures at the sand corresponding to 1,000,000, 2,000,000, 3,000,000, and 5,000,000 cubic feet of gas per 24 hours are 586, 560, 534, and 480 pounds per square inch absolute, respectively. When the correction factor of 50 pounds per square inch is added to each of the back pressures the values become 636, 610, 584, and 530 pounds per square inch absolute, respectively; therefore the data used for plotting the corrected curves are:

P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	$P_f^2 - P_s^2$, thousands	Q, M cu. ft. per 24 hours
664	636	36.4	1,000
..	610	68.8	2,000
..	584	99.8	3,000
..	530	160.0	5,000

The curve corrected for water column is shown as curve *B* of figure 13. Curve *A* (fig. 13) is the same as curve *C* (fig. 9). The correction of 50 pounds per square inch decreases the indicated rate of delivery corresponding to a given value of the pressure factor $P_f^2 - P_s^2$ but increases the value of the pressure factor when P_s is atmospheric pressure, so the absolute open flow from curve *B* is approximately 15,000,000 cubic feet of gas per 24 hours compared with 14,000,000 cubic feet per 24 hours from curve *A*. Correcting the shut-in formation pressure and the back pressures at the sand for the pressure due to a column of liquid has a relatively small effect on the interpretation of results, as is discussed in detail in appendix 8.

Back-pressure data and interpretations applicable to gas wells with liquid in the well bore and in the adjacent pore spaces of the producing strata are subject to error if there are changes of the pressure of the column of liquid in the well bore or in the permeability of the producing formation due to liquid during the back-pressure test. Changes in permeability due to liquid occur with changes of pressures and delivery rate. The presence of a constant column of liquid in the well bore during the back-pressure test does not have any appreciable effect on the consistency of the plotted relation between the rate of flow and the pressure factor throughout the range of back-pressure data. The study of liquids in gas wells has been supplemented in part by a special series of experiments that are being conducted to determine the effect of the liquids on the character of the gas flow through bonded and uncemented sands. The results of the study of the flow of air through unbonded sands containing a stationary and constant quantity of liquid in the pore spaces are given in appendix 10.

USE OF TUBING IN GAS WELLS

The removal of liquid from gas wells [33] is one of the most important problems confronting natural-gas producers. Liquid in the well bore and in the producing formation may be water, crude oil, "gasolines," and liquefied gases that vaporize when not subjected

[33] Tough, F. B., Methods of Shutting Off Water in Oil and Gas Wells: Bull. 163, Bureau of Mines, 1918, 122 pp.
Ambrose, A. W., Underground Conditions in Oil Fields: Bull. 195, Bureau of Mines, 1921, 238 pp.
Swigart, T. E., and Beecher, C. E., Manual for Oil and Gas Operations: Bull. 232, Bureau of Mines, 1923, 145 pp.
Williams, I. B., Brandenthaler, R. R. and Walker, Morgan, Design and Operation of Gas-Well Siphons: Tech. Paper 460, Bureau of Mines, 1929, 45 pp.

to the high pressures in the reservoir, and its removal or exclusion from the well is of importance. Liquid in the sand and in the well bore often decreases the capacity of the well to deliver gas and prevents proper interpretation of the producing characteristics of the well from data observed at the wellhead.

The problem of removing water from gas wells is of particular importance in old fields where water has been allowed to penetrate

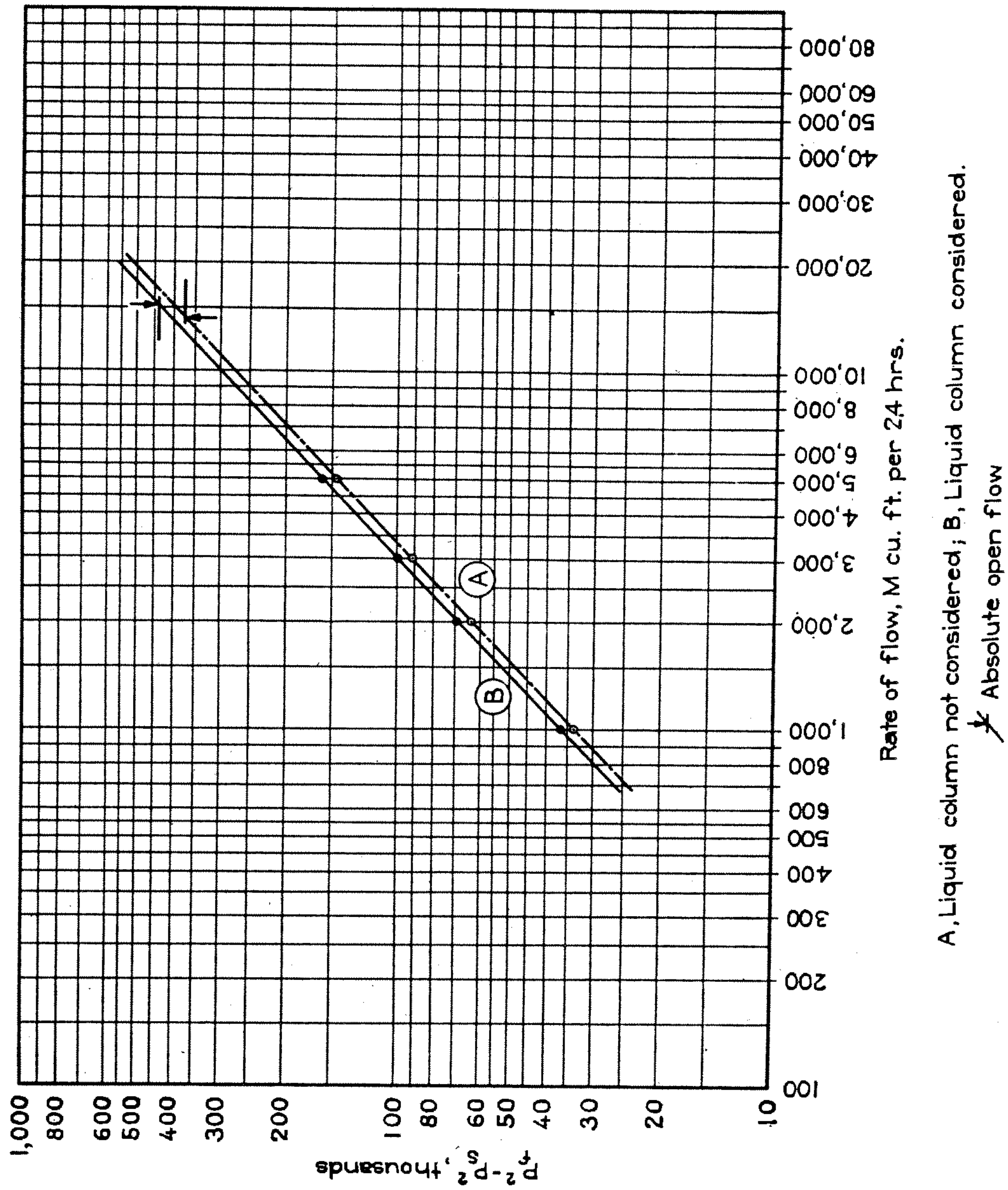


FIGURE 13.—Effect of liquid on interpretation of back-pressure data. (Constant liquid column in well bore)

the producing horizons. The removal of water, however, is of secondary importance where it is possible to exclude water by repairing the wells or by operating them at high back pressures. Whenever possible the source of water should be determined and remedial measures taken to prevent it from entering the wells. Waters entering gas wells may be classed as top, middle or intermediate, edge, and bottom, according to the location of the entry of the water into the well. If satisfactory water shut-offs cannot be made all or part of the water must be removed from the wells by pumping, bailing, swabbing, blowing through casing or tubing, or siphoning before they can be operated satisfactorily.

Many operators use tubing in gas wells to facilitate removal of water. The tubing is opened to the atmosphere, and if the gas velocity is high enough the liquid can be lifted in the tubing. In some wells the tubing has to be opened frequently to maintain a liquid level low enough for efficient production of gas; otherwise, liquid accumulates in the well until the hydrostatic pressure of the column of liquid in the tubing is greater than the gas pressure and the flow of gas into the well stops.

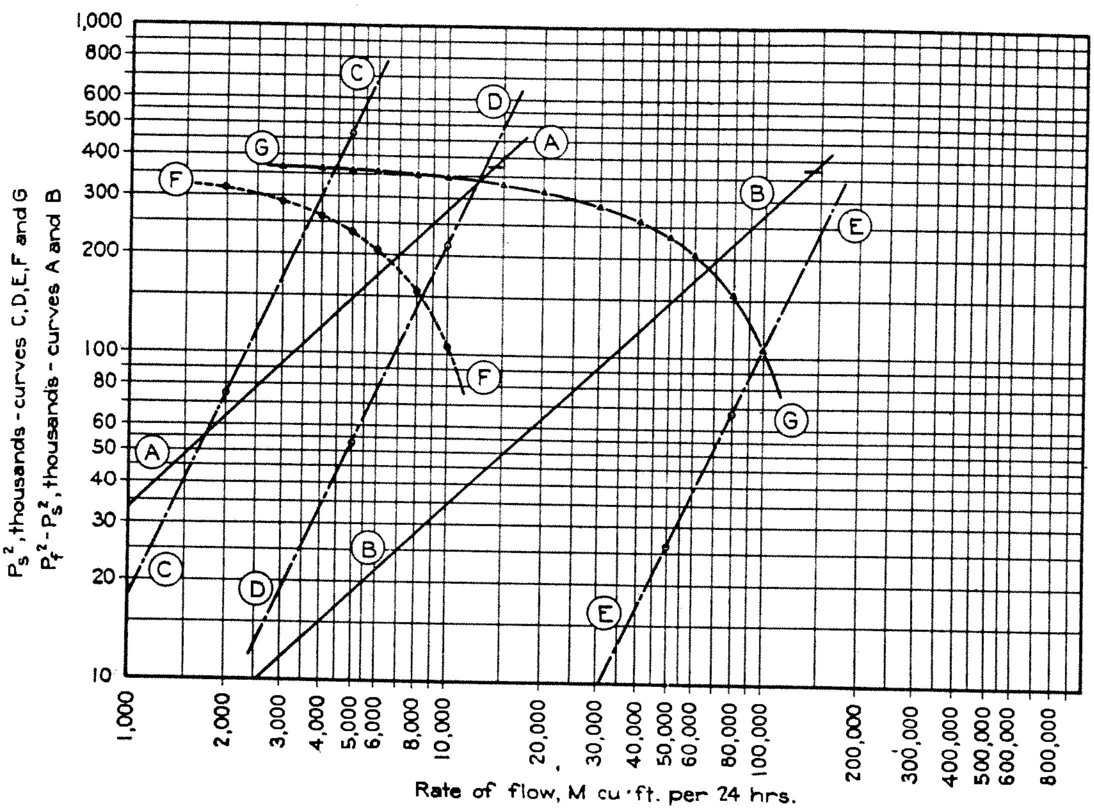
Many wells completed as gas wells produce crude oil in commercial quantities with the gas when reservoir pressures have been partly depleted or when the wells are operated at relatively low back pressures. The problem of the operator then becomes one of oil production and gas conservation rather than the prevention of liquid entry in the well or its removal from the well bore. The entry in many gas wells of small quantities of low-grade crude oil at relatively low rates, however, presents a serious operating problem, particularly if salt water is present, since the resulting emulsion is considerably more difficult to remove than " uncut " crude oil or water. Operating efficiencies of wells producing gas and oil often are increased by installing tubing to facilitate the removal of liquids entering the well bore and prevent their accumulation and subsequent emulsification in the well bore at the gas horizon, and by selecting tubing and inlet parts that will tend to reduce emulsification of the liquids to a minimum while they are being removed through the tubing by the flow of gas. Some gas wells subject to oil emulsions or accumulations of paraffin can be treated with acid; however, the rates of deliveries of gas from the producing formation usually are relatively low, and the results of experimental remedial measures should be studied carefully before extensive programs involving considerable expenditures are begun.

The methods that have been described for removal of water can be used for removing gasolines from wells, the method selected depending on conditions in the individual well. In some wells the velocity of the flowing gas is sufficient to lift the liquids and discharge them with the gas if the well is opened to the atmosphere A modification of this method is to install a choke nipple or orifice plate at the wellhead, restricting gas flow to the minimum velocity necessary to lift the liquid.

The removal of liquefied gas from gas wells generally is not a serious problem, except possibly while the pressures in the reservoir are high. The hydrocarbons exist as a liquid only under conditions of high pressure, and after the field has been partly depleted and the pressure in the reservoir is lowered the hydrocarbons exist as a gas, and the problem of liquid removal is eliminated.

The use of tubing to remove liquid from gas wells has several advantages. Tubing increases the velocity of flow and places a high back pressure on the sand while liquid is being removed. Such pressure retards the rate of liquid entry into the drainage space of the well and into the well bore itself, helps control deliveries of gas from high-pressure gas wells, protects the casing from erosion and wear in wells that produce abrasive materials with gas, and protects the producing formation.

Pressures that can be maintained at the wellhead for different rates of gas delivery into a pipe-line system are important operating considerations. Wellhead pressures corresponding to the same delivery rates through tubing and casing differ widely because of the greater velocity and pressure drop due to friction for flow through



A and B, Relationships between Q and $P_f^2-P_s^2$ describing two gas wells

C, D " E, " " Q " P_s^2 showing maximum delivery capacities of 2-inch tubing, 3-inch tubing and 8¼-inch casing, respectively, corresponding to different pressure conditions

F and G, Relationships between Q and P_s^2 showing delivery capacities from producing sand, based on A and B, respectively

⁄, Absolute open flow from A and B

Intersection of F or G with C, D or E denotes open flow or maximum gas delivery through producing string

FIGURE 14.—Comparison of maximum gas deliveries through different sizes of producing strings based on back-pressure data

tubing compared with flow through casing. Therefore, pressures at the wellhead should be considered in designs of tubing installations and programs for future operation of wells. For example, consider two gas wells on which back-pressure tests were made, giving the results illustrated by curves *A* and *B* (fig. 14). Curve *A* (fig. 14) is the same as curve *C* (fig. 9). The data and calculations of the back-pressure test illustrated by curve *C* (fig. 9) are shown in table 12. The well represented by *A* (fig. 14) produced gas of gravity 0.56 from a depth of 3,280 feet through 8¼-inch casing. The shut-in pressure at the wellhead was 563 pounds per square inch gage, and the computed shut-in pressure at the sand was 614 pounds per square inch absolute. The absolute open flow of the well as shown by curve *A* (fig. 14) is 14,200,000 cubic feet of gas per 24 hours. Curve *B* is an assumed case, with all of the factors defining the well and its producing characteristics the same as for curve *A*, except the coefficient *C* of the flow equation, $Q=C(P_f^2-P_s^2)^n$. The absolute open flow of the well represented by curve *B* is 142,000,000 cubic feet of gas per 24 hours. Calculations made to determine the pressures that would have to be maintained at the wellhead and at the sand for the wells represented by curves *A* and *B*, corresponding to different rates of flow through 2-inch tubing, 3-inch tubing, and 8¼-inch casing, are shown in table 16.

TABLE 16.—*Comparison of working pressures at the sand and at the wellhead for flow of gas through different sizes of producing strings*[1]

Rate of flow, M cu. ft. per 24 hours	Well 1				Well 2			
	P_s[3] lb. per sq. in. absolute	P_w[4], lb. per sq. in. absolute			P_s[3] lb. per sq. in. absolute	P_w[4], lb. per sq. in. absolute		
		8¼-in. casing	3-in. tubing	2-in. tubing		8¼-in. casing	3-in. tubing	2-in. tubing
Open flow[2]	15	15	15	15	326	15	15	15
8,000	394	369	..	..	591	554	434	..
5,000	482	452	398	..	599	562	517	..
3,000	534	501	484	321	605	567	553	417
2,000	560	525	518	459	607	569	563	511
1,000	586	550	548	535	611	573	571	561

[1] Fig. 14.

[2] Well 1.

	Cu. ft. per 24 hours
Absolute open flow	= 14,200,000
Open flow throngh 8¼-inch casing	= 14,200,000
Open flow through 3-inch tubing	= 8,250,000
Open flow through 2-inch tubing	= 3,750,000

Well 2.

Absolute open flow	= 142,000,000
Open flow through 8¼-inch casing	= 100,000,000
Open flow through 3-inch tubing	= 12,300,000
Open flow through 2-inch tubing	= 4,400,000

[3] P_s = back pressure at sand, lb. per sq. in. absolute.

[4] P_w = back pressure at wellhead, lb. per sq. in. absolute.

The absolute open flow of well 1 (curve *A*) is 14,200,000 cubic feet of gas per 24 hours, and the open flow through the 8¼-inch casing is the same because the pressure drop in the casing due to friction is negligible. The open flow through 3-inch tubing (from the intersection of curves *D* and *F*[34]) is 8,250,000 cubic feet of gas per 24 hours, and the open flow through 2-inch tubing (as determined by the intersection of curves *C* and *F*) is 3,750,000 cubic feet of gas per 24 hours. Back pressures at the sand corresponding to delivery rates of 8,000,000, 5,000,000, 3,000,000, 2,000,000, and 1,000,000 cubic feet of gas per 24 hours are 394, 482, 534, 560, and 586 pounds per square inch absolute, respectively. Pressures that can be maintained at the wellhead for gas flow through the 8¼-inch casing at corresponding rates of delivery are 369, 452, 501, 525, and 550 pounds per square inch absolute, respectively. Most of the

[34] See appendix 7 for explanation of calculations.

difference between the pressures at the face of the sand and at the wellhead is due to the pressure corresponding to the weight of the column of gas, because the pressure drop in the producing string is negligible. For flow through 3-inch tubing the delivery of 8,000,000 cubic feet of gas per 24 hours would approximate conditions of open flow. The pressures at the wellhead corresponding to flows of 5,000,000, 3,000,000, 2,000,000, and 1,000,000 cubic feet of gas per 24 hours through the 3-inch tubing are 398, 484, 518, and 548 pounds per square inch absolute, respectively. Therefore, there are differences between the pressures at the wellhead for flow through 3-inch tubing and 8¼-inch casing of 54, 17, 7, and 2 pounds per square inch, corresponding to delivery rates of 5,00,000, 3,000,000, 2,000,000, and 1,000,000 cubic feet of gas per 24 hours, respectively. The delivery of gas from the well through 2-inch tubing under conditions of open flow is 3,750,000 cubic feet per 24 hours. The pressures at the wellhead corresponding to flow rates of 3,000,000, 2,000,000, and 1,000,000 cubic feet of gas per 24 hours through 2-inch tubing are 321, 459, and 535 pounds per square inch absolute, respectively. The differences between the wellhead pressures for flow through 2-inch tubing and 8¼-inch casing are 180, 66, and 15 pounds per square inch, corresponding to delivery rates of 3,000,000, 2,000,000 and 1,000,000 cubic feet of gas per 24 hours, respectively.

The pressures at the wellhead and at the sand for well 2 (curve *B*, fig. 14) are compared similarly to those of well 1. The back pressures at the wellhead and at the sand are greater than for well 1 due to the greater delivery capacities of well 2. The delivery rates of gas from the formation into the well bore at different back pressures and pipe-line requirements therefore are factors that should be considered in designing tubing installations, for which the results of back-pressure tests can be used advantageously. Tubing is used primarily to facilitate the removal of liquid from the sand and the well bore and in some high-pressure wells to control the delivery of gas; however, in some wells high rates of gas delivery are taken from the annular space betwen the tubing and the casing, and low rates are taken through the tubing. Greater volumes of gas can be obtained from the annular space between the casing and tubing than from the tubing, and the deliveries can be made while a high back pressure is maintained at the wellhead.

The results of back-pressure tests on gas wells in the Texas Panhandle field before and after the wells are tubed are compared in figure 15. The well illustrated by example I (fig. 15) was tested first on March 28, 1930, when it was noticed that a small amount of liquid was produced with the gas. The shut-in pressure at the wellhead was 401 pounds per square inch gage. Curve *A* (example I) shows the results of the back-pressure tests. Two-inch tubing was installed in the well on July 1, 1930, and a second back-pressure test was made on September 18, 1930, when the shut-in pressure at the wellhead was 393 pounds per square inch gage. There was therefore a decline in shut-in pressure of only 8 pounds per square inch in 174 days. The results of the second back-pressure test are shown by curve *B* (example I). The pressure-flow relationship represented by curve *B* is consistent with the producing characteristic established from back-pressure tests on normal gas wells, and comparison of curves *A* and *B* indicates an apparent increase in the ability of the well to produce gas after the tubing was installed. It is not certain, however, from the data available whether the variation between curves *A* and *B* was due to unaccounted-for error in computing bottom-hole data or actually to an increase in the ability of the well to deliver gas. Similar comparisons of the results of back-pressure tests made before and after tubing other gas wells in the same gas-producing area are shown by curves *C* and *D* (example II),

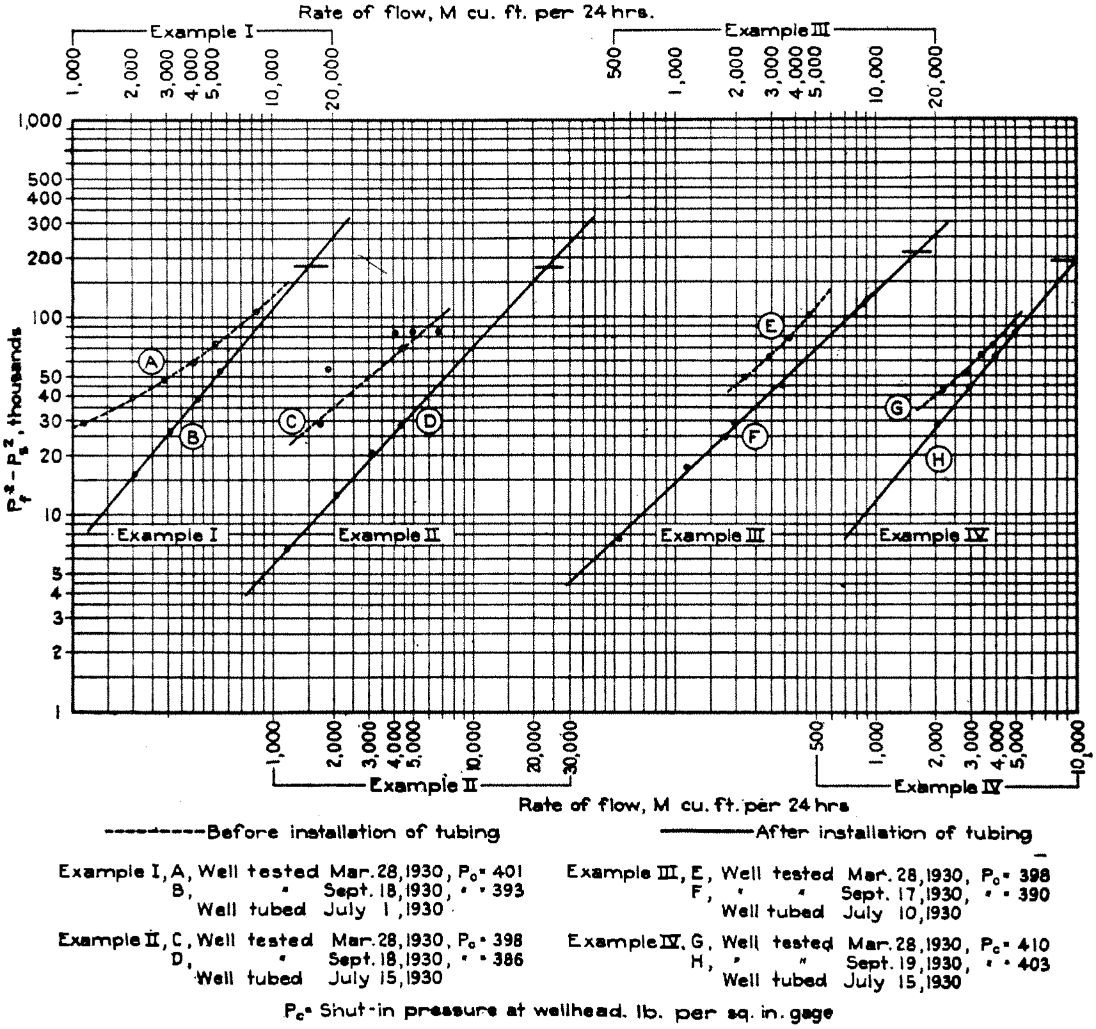


FIGURE 15.—Comparison of gas deliveries from wells subject to liquid entry before and after installation of tubing

curves *E* and *F* (example III), and curves *G* and *H* (example IV) in figure 15.

The logs of the gas wells drilled in the area, which are representative of the examples shown in figure 15, indicate that the wells produce from a limestone formation and that in several wells the supply of gas is supplemented by gas from the so-called granite-wash formation. The wells were completed with 8¼-inch casing usually cemented about 200 feet above the first "lime pay," which is found 2,000 to 2,500 feet below the surface of the ground. The entire limestone horizon is not productive but contains several productive lenses in the 200 to 400 feet below the first productive stratum. In

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the majority of wells, therefore, there was 200 feet of " open hole " above the upper gas-producing stratum and 400 to 600 feet of open hole above the lower gas-producing stratum. Entry of liquids into wells completed without casing off the formation between or above the producing horizons affects not only the delivery capacities of the wells but also tends to wash off shale " cavings " from the sides of the well bores and necessitates cleaning out the wells at frequent intervals. The use of tubing in such wells facilitates removal of liquids and reduces the tendency of the loose shale to cave from walls of the open holes.

Back-pressure tests on a group of 21 gas wells in the Depew field, Oklahoma, also have given valuable information on the use of tubing in gas wells. The wells produce from the Dutcher sand at a depth of approximately 3,300 feet. The average thickness of the productive formation in the Depew field is approximately 10 feet, and wells penetrate the producing formation 1 to 13 feet. The length of the open hole between the shoe and the top of the producing horizon ranges from 0 to 100 feet and averages approximately 20 feet. At the time of the tests 10 wells were equipped with 2-inch tubing packed off at the wellhead, and in 11 wells the casing was the producing string. The tubed wells were allowed to produce gas through the tubing into the pipe line for a few hours before being shut in, and the shut-in pressure at the wellhead was observed and recorded. The back-pressure tests then were made. The pressure-flow relationships obtained from the back-pressure data were consistent with the producing characteristics established from back-pressure tests on so-called normal gas wells, indicating that the liquid conditions in the wells did not change during the tests. Pressure-flow relationships for several wells which were not tubed, however, deviated considerably from the straight-line characteristic established on normal wells, due probably to error in the calculation of bottom-hole data, showing that often the producing characteristics of untubed wells cannot be determined with the same assurance as for tubed wells.

The results of back-pressure tests conducted in the Texas Panhandle and in the Depew fields, together with results of analogous back-pressure tests in other gas-producing areas, show that the bottom-hole data calculated from observations at the wellheads of tubed wells is more reliable than that computed for wells that are not tubed and that tubing facilitates the removal of water, permits more efficient production operations, and in some wells actually leads to an increase in the rate of production of gas.

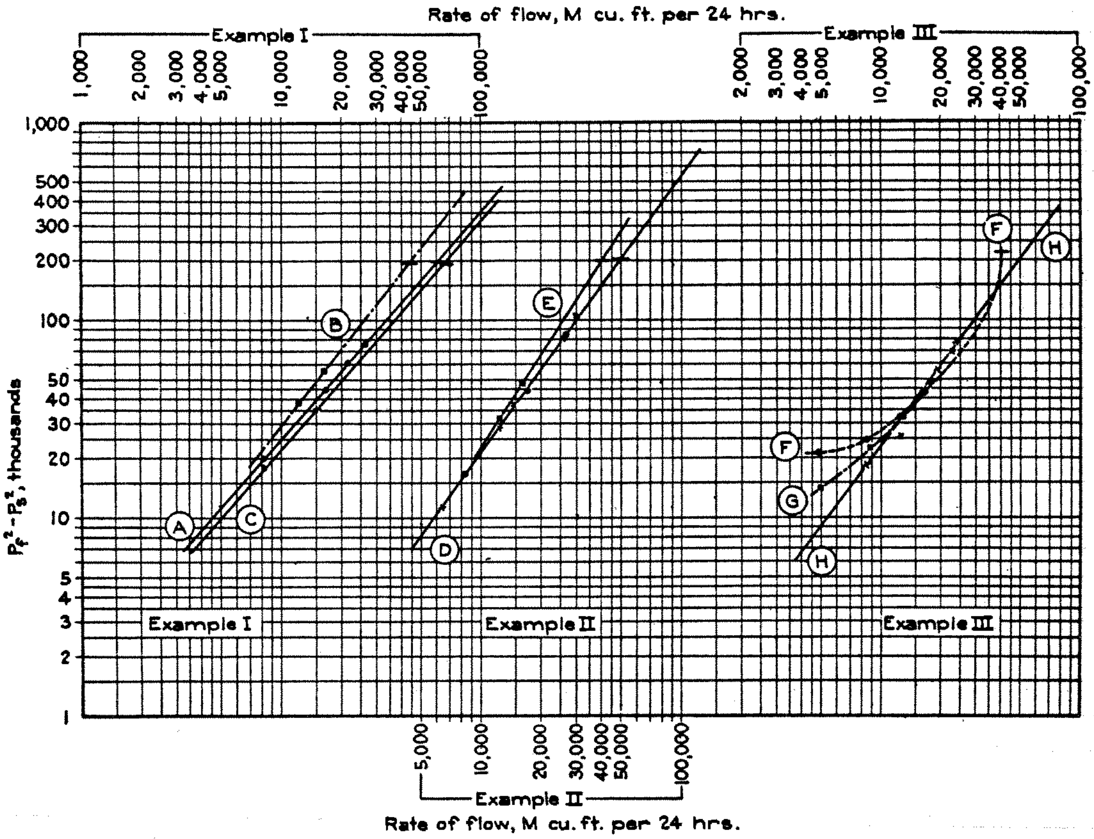
PRESENCE OF CAVINGS IN GAS WELLS

The delivery of gas from many natural-gas wells is affected by the presence of cavings or of materials from the formations in the well bore. The substance found in wells often is of such nature that it offers about as effective a seal to the flow of gas into the well bore as a head of liquid of equivalent height. However, in some wells the substance withstands differential pressures considerably in excess of its weight and can seal off the gas effectively. The gas can be sealed off where it is produced from a lensed-type limestone formation, with the intervening shale beds exposed in the open hole. In one well where the shut-in pressure was approximately 425 pounds per square inch gage and the open-flow volume was approximately 40,000,000 cubic feet of gas per 24 hours a plug formed at the bottom of the well and extending but a few feet above the upper producing lens effectively shut off the flow of gas into the well when the pressure at the wellhead was reduced to that of the atmosphere.

In general, the effect of cavings in the well bore on delivery capacities depends on the delivery rates at which gas is produced, the quantity of cavings that accumulate, and the thickness of the producing formation covered by the cavings. Delivery rates influence the effectiveness of cavings in the well bore as a seal to gas flow Evidence of this was noticed when the pressure-flow relationships obtained under conditions of increased delivery rates during back-pressure tests on wells containing cavings were compared with relationships common to the normal operation of wells. During back-pressure tests on some gas wells with cavings in the well bore, where observations were made by increasing the delivery rates in the test series, there were relatively sudden increases in wellhead pressures accompanied by increased delivery rates while pressure and flow conditions were stabilizing. The amount of caving from the walls of the open holes varies in different wells and in the same wells under different flow conditions, and cavings allowed to accumulate in wells often shut off lower gas-producing strata. Wells often are "taken out of operation" to clean them of cavings, but usually cavings can be removed by "blowing" a well occasionally when large quantities have not been allowed to accumulate.

The results of a series of back-pressure tests on a group of gas wells in the Texas Panhandle field, illustrating the effect of cavings in the well bore on the delivery capacities of the wells, are shown in figure 16. The wells produce gas from a limestone formation, often supplemented by production from the "granite wash." Example I shows the results of a series of back-pressure tests on a gas well 2,720 feet deep producing through 10-inch casing. According to the well log the upper sand was at a depth of 2,070 feet, and the 10-inch casing was set 2,044 feet below the surface of the ground. There was therefore 676 feet of open hole below the 10-inch casing. The well had been open-flowed in March 1930. The results of a back-pressure test made on June 23, 1930, when the shut-in wellhead pressure was 407 pounds per square inch gage, are shown by curve *A*. The results of a second back-pressure test made on September 29, 1930, when the shut-in pressure at the wellhead was 405 pounds per square inch gage, are shown by curve *B*.

A comparison of the results of the two tests indicates that the delivery capacity of the well corresponding to a $P_f^2 - P_s^2$ of 30,000 had decreased approximately 14 percent, whereas the shut-in pressure had decreased only 2 pounds per square inch. After the second back-pressure test the well was opened to the atmosphere, a considerable quantity of cavings was blown out, and then the well was shut in until November 13, 1930, when a third back-pressure test was made. The shut-in pressure at the wellhead was the same as before—405 pounds per square inch gage. The results of the test are shown by curve C. A comparison of curves B and C indicates an increase of approximately 27 percent in the delivery capacity of the well, corresponding to a $P_f^2-P_s^2$ of 30,000 due to the removal of cavings from the well bore. The fact that the delivery capacity of the well during the third test (curve C) is somewhat greater than that during the first test (curve A) indicates that there was an accumulation of cavings in the well bore at the time of the first test.



Example I, A, Well tested June 23, 1930, P_c = 407
B, " " Sept. 29, 1930, " = 405
C, " " Nov. 13, 1930, " = 405

Example II, D, " " June 24, 1930, " = 411
E, " " Sept. 29, 1930, " = 409
D, " " Nov. 13, 1930, " = 409

Example III, F, Well tested June 19, 1930, P_c = 426
G, " " June 20, 1930, " = 426
H, " " Aug. 8, 1930, " = 424

P_c = Shut-in pressure at wellhead, lb. per sq. in. gage

Results of first and third tests of example II coincide
Cavings removed by blowing well after tests B, E and G

FIGURE 16.—Effect of cavings in well bore on delivery capacities of gas wells showing changes that occur during period of time that cavings accumulate

Example II (fig. 16) shows the results of a series of back-pressure tests on a gas well 2,815 feet deep producing through 10-inch casing. The upper gas-producing stratum was at a depth of 2,322 feet, and the 10-inch casing was set 2,047 feet below the surface of the ground, leaving 768 feet of open hole. The first back-pressure test was conducted on the well on June 24, 1930, when the shut-in pressure at the wellhead was 411 pounds per square inch gage. The results of the test are shown by curve D. The results of a second back-pressure test conducted on September 29, 1930 (curve E), when the shut-in pressure at the wellhead was 409 pounds per square inch gage, indicate a decrease in the delivery capacity of the well corresponding to a $P_f^2 - P_s^2$ of 30,000 or approximately 6 percent. The well then was blown and a considerable quantity of cavings removed. The results of a third test, which was made on November 13, 1930, gave a relationship that coincided with curve *D*, indicating that removal of cavings between the second and third tests had restored the delivery capacity of the well to that existing at the time of the first test.

Example III (fig. 16) shows the results of a series of back-pressure tests on a gas well 2,753 feet deep producing through 8¼-inch casing. The upper gas-producing stratum is at a depth of 2,645 feet, and the 8¼-inch casing was set at a point 2,608 feet below the surface of the ground, leaving 145 feet of open hole. Curve *F* shows the results of the first back-pressure test, which was conducted on June 19, 1930 when the shut-in pressure at the wellhead was 426 pounds per square inch gage. As shown by the curve, the relationship between delivery rate and the pressure factor $P_f^2 - P_s^2$ was not consistent with results obtained from back-pressure tests of normal gas wells. The presence of a film of mud on the orifice plates of the flow prover used for measuring the delivery rates suggested the possibility of cavings in the well bore. Accordingly, the well was blown, and some of the cavings were removed. A second back-pressure test was conducted on the well on the following day (June 20, 1930), and the results of the test are shown by curve *G*. The delivery capacities of the well throughout a range of high back pressures shown by curve *G* are greater than those represented by curve *F*, but the results still are inconsistent with those expected from a normal gas well under favorable operating conditions. Thereupon the well was blown again, and more cavings were removed. A third back-pressure test was made on August 8, 1930, when the shut-in wellhead pressure was 424 pounds per square inch gage. The results of the test are shown by curve *H*. The delivery capacities of the well under normal operating conditions were improved greatly by the removal of the cavings, but still little or no difference was noticed in the delivery capacities at low back pressures and high rates of flow.

The results of the back-pressure tests shown by example III (fig. 16) and of tests on a number of other gas wells suggest the possibility of an abrupt change of coefficient *C* of the flow equation $Q = C(P_f^2 - P_s^2)^n$ during a back-pressure test. The results of a series of back-pressure tests on three gas wells illustrating the effect of cavings in the well bore are given by the curves in figure 17.

Example I (fig. 17) presents the results of back-pressure tests on a gas well 2,810 feet deep producing gas through 10-inch casing. The upper gas-producing stratum was at a depth of 2,310 feet, and the casing was set 2,084 feet below the surface of the ground, leaving 726 feet of open hole. Curves *A*, *B*, and *C* (fig. 17) represent results of back-pressure tests on June 24, 1930, November 14, 1930, and August 27, 1931, respectively, and show that the delivery capacities of the well, especially at high back pressures, were increasing. The shut-in pressures at the wellhead corresponding to the conditions of curves *A*, *B*, and *C* were 424, 417, and 407 pounds per square inch gage, respectively. A fourth test was made on October 11, 1931, when the shut-in wellhead pressure was 411 pounds per square inch gage. The results of the test as illustrated by curve *D* show a considerable decrease in the delivery capacities of the well throughout a range of high back pressures and an abrupt change during the back-pressure test (indicated by the break in curve *D*) in the delivery capacity of the well at one particular pressure condition. Interpretation of the results of the back-pressure test by drawing an average curve through the plotted points shown by *D*

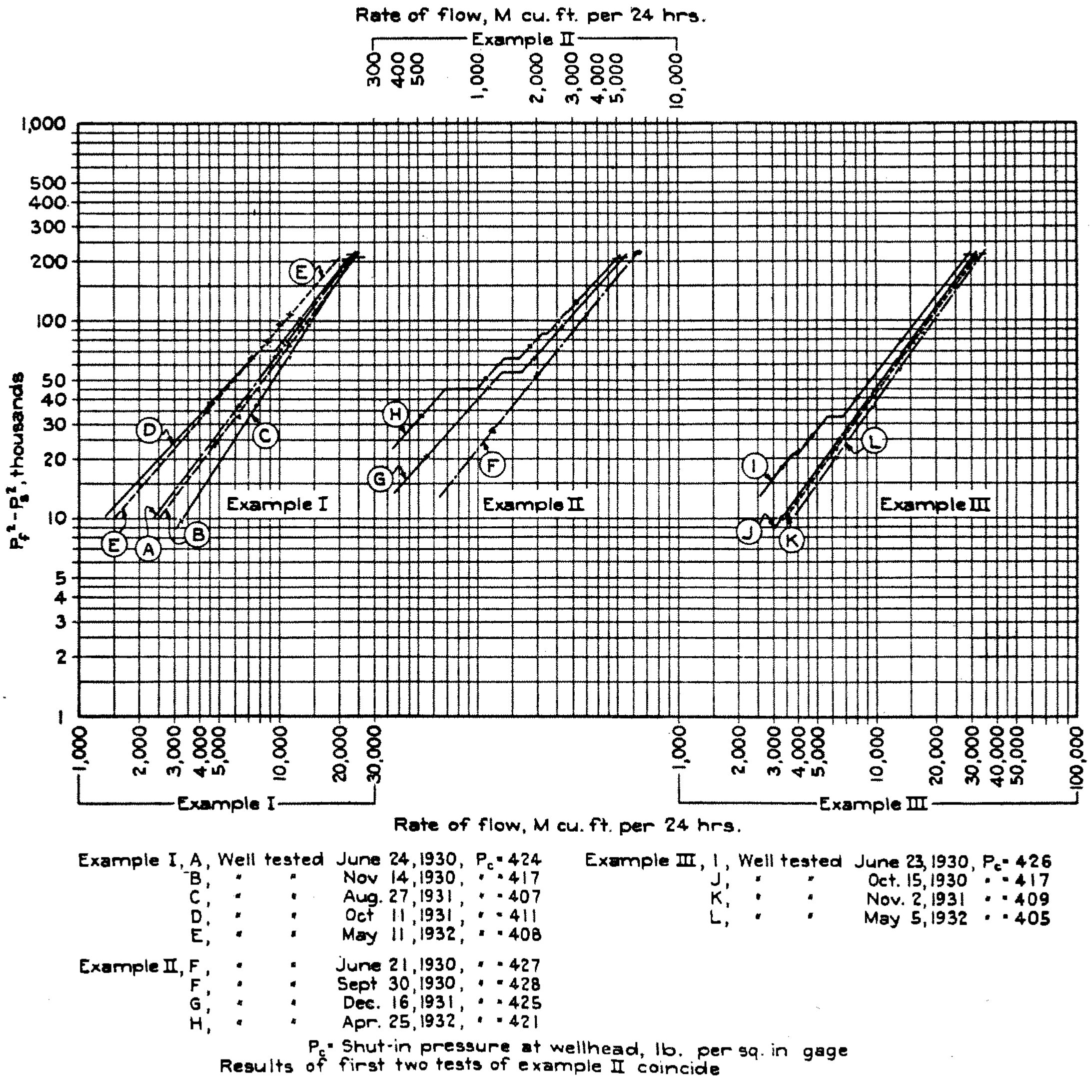


FIGURE 17.—Effect of cavings in well bore on delivery capacities of gas wells showing changes that occur during back-pressure tests

might cause the use of an erroneous *n* of the flow equation. A fifth back-pressure test was conducted on May 11, 1932, when the shut-in wellhead pressure was 408 pounds per square inch gage. The results of the test (curve *E*) do not indicate any abrupt change in the delivery capacity of the well during the test but show that the delivery capacities throughout the range of pressure conditions were considerably less than those described by curves *A*, *B*, and *C*.

The results of back-pressure tests on a gas well, illustrated by example II (fig. 17), also show changes in delivery capacities that can occur during the progress of a test when cavings have accumulated in the well bore. The results of the tests on June 21, 1930 and on September 30, 1930 coincided (see curve *F*). The shut-in wellhead pressures when the tests were made were 427 and 428 pounds per square inch gage, respectively. A third back-pressure test was made on December 16, 1931, when the shut-in wellhead pressure was 425 pounds per square inch gage. The delivery capacities of the well throughout the range of pressure conditions were decreased noticeably compared with those described by curve *F*, and there probably was an abrupt change in the delivery capacity of the well during the test, as indicated by curve *G*. A fourth back-pressure test was made on April 25, 1932, when the shut-in pressure at the wellhead was 421 pounds per square inch gage. The results are shown by curve *H*, which represents graphically the possibility of a series of abrupt changes in the delivery capacities of the well under each of several pressure conditions and indicates decreases in the delivery capacities throughout the range of pressure conditions compared with those described by curves *F* and *G*.

Example III (fig. 17) shows the results of back-pressure tests on a gas well 3,087 feet deep producing gas through 10-inch casing. The upper gas-producing stratum was at a depth of 2,800 feet, and the casing was set 2,017 feet below the surface of the ground, leaving 1,070 feet of open hole. The first back-pressure test was made on June 23, 1930, when the shut-in wellhead pressure was 426 pounds per square inch gage. The results are shown in curve *I*. Evidently cavings had accumulated in the well bore and affected not only the delivery capacities of the well throughout a range of pressure conditions but caused abrupt changes in flow conditions during the test. Curves *J*, *K*, and *L* show the results of back-pressure tests on October 15, 1930, November 2, 1931, and May 5, 1932, when respective shut-in wellhead pressures were 417, 409, and 405 pounds per square inch gage. The results give consistent relationships, and evidently there were gradual increases in the delivery capacities of the well corresponding to the respective back-pressure tests. It is not known definitely whether the increase in delivery capacites was due to a changed effect of cavings in the well bore or to changes in the characteristics of the flow of the gas through the sand.

The results of the interpretation of back-pressure data from wells subject to accumulation of cavings in the well bore (figs. 16 and 17) show that in many gas wells cavings affect the delivery capacities of the wells by decreasing the rate of flow of gas throughout the range of pressure conditions to which the well can be subjected and by causing abrupt changes in the delivery capacities under certain conditions of pressure. On the other hand, the cavings often are of such nature that there is no appreciable effect on the delivery capacities of the wells. All these factors should be considered when back-pressure data are interpreted.

STABILIZATION OF PRESSURE-FLOW CONDITIONS DURING BACK-PRESSURE TESTING AND OPERATION OF GAS WELLS

Rates of deliveries of gas from gas wells usually are controlled and regulated at the wellhead. If a gas well that has been delivering gas at a constant rate into a pipe-line system is shut in the pressure at the wellhead will rise until there is no further flow of gas through the producing formation to the well. On the other hand, if a well that has been shut in is opened at the wellhead to permit gas to flow into the pipe-line system the pressure drops until the delivery rate and the pressure become constant. Moreover, if the rate at which a well delivers gas into a pipe-line system is changed by regulating the flow at the wellhead there will be a changing pressure-flow condition in the well and adjacent reservoir for a period of time before the delivery rate and pressure become constant. The approach to and reaching of constant delivery rates and pressures, following an adjustment in the operating condition of a gas well by regulation at the wellhead, are termed in this report the " stabilization of pressure-flow conditions."

The time required for stabilization of pressure-flow conditions varies considerably for different gas wells. In many natural-gas wells the pressure-flow conditions become stabilized quickly; that is, they become constant within 5 to 20 minutes after changes in the delivery rates. In other wells, however, the time required for stabilization of pressure-flow conditions is longer than 20 minutes, and in many of the wells on which back-pressure tests were made 2 to 3 days were required to establish stabilized pressure-flow conditions. Tests on a number of gas wells producing from the tight, small-grained, closely-bonded Speechley sand in West Virginia indicated a condition of extreme slowness toward stabilization, and the pressures in some of the wells were not constant after they had been shut in for 2 months. In general, the greater part of the change in delivery rates and pressures occurs within a relatively short period after the flow is adjusted, and the remainder takes considerable time, especially in " slow-settling " wells.

Pressure-flow conditions in some wells equipped with large producing strings and capable of producing gas only at low delivery rates stabilize slowly after a change in flow.

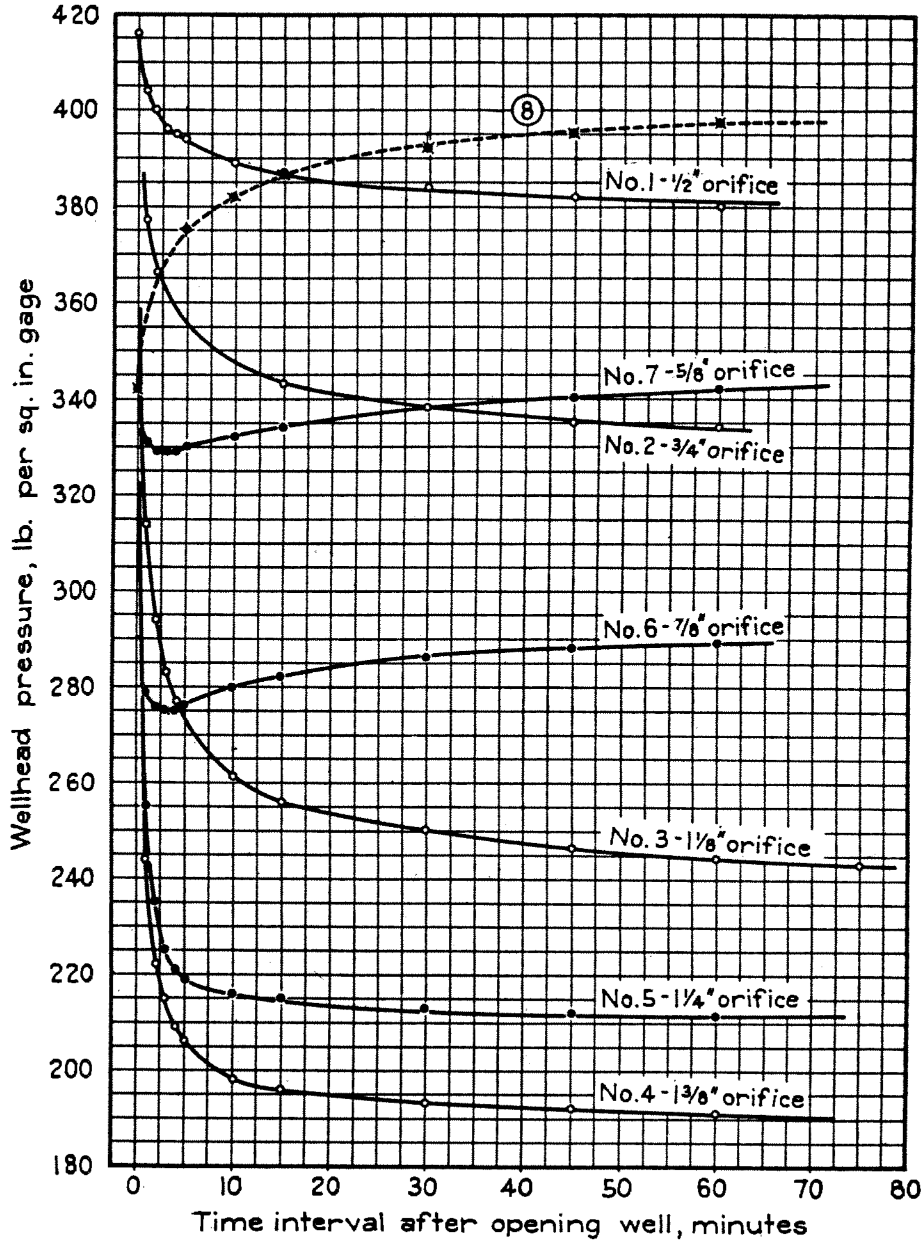
The slow stabilizing characteristic of many wells evidently does not depend entirely upon the relationship between delivery capacities and the normal void space within the drainage zone of a well because it often was noticed that flow rates from wells capable of delivering large volumes of gas per 24 hours stabilized more slowly than deliveries from wells similarly completed and of equal depths but capable of producing only relatively small volumes of gas. The authors noted one well with an absolute open-flow volume of approximately 100,000,000 cubic feet of gas per 24 hours that evidenced a slower stabilization characteristic than other wells in the same area of the field having absolute open-flow volumes less than 10,000,000 cubic feet of gas per 24 hours.

A large interior volume in the producing string in which gas can accumulate and a small flow rate from the sand to the well doubtless will cause slower stabilization than ordinarily is experienced, but even in such wells there is a definite limit to the time required for at least approximate stabilization. In other wells the prolonged period required for pressure-flow stabilization obviously has been caused by changes of liquid conditions in the sand and in the well bore. However, in many wells there seemingly was no explanation for the period required for flow stabilization except the possibility of the effect of reservoir structure and permeability variations in the producing sand.

Slow stabilization of pressure-flow conditions affects back-pressure tests of gas wells in two ways: (1) The time required for an accurate back-pressure test often is excessively long, and (2) unless conditions of slow stabilization are recognized calculations based on observations taken under conditions of unstabilized flow may cause erroneous interpretations of delivery capacities. Relationships between delivery rates and pressure factors $P_f^2 - P_s^2$, obtained on wells from such calculations often are inconsistent with relationships obtained on normal gas wells, and even if the relationships apparently are consistent results of calculations based on unstabilized flows may indicate an erroneous n (tangent of the angle A of fig. 5) of the flow equation $Q = C(P_f^2 - P_s^2)^n$. Conditions of slow stabilization of pressure and flow noticed during back-pressure tests also are experienced during normal operation of some gas wells in delivering gas into pipe-line systems.

Slow stabilization of pressure-flow conditions also has been noticed when open flows of some wells are gaged with Pitot tubes, and the deliveries calculated from observed impact pressures on Pitot tubes were found to be greater for unstabilized than for stabilized flows. In making a certain back-pressure test the delivery rates obtained were measured under stabilized conditions of flow, and therefore the absolute open flow interpreted from the results of the test was the delivery to be expected under stabilized flow conditions. The absolute open flow determined from the back-pressure test, however, was only about 25 percent of the open flow gaged with a Pitot tube about 3 months before the back-pressure test was made, and it was suspected that the gaged open flow had been obtained under conditions of unstabilized flow. Accordingly, a second gage was made of the well with a Pitot tube after the well had been allowed to flow wide open for several hours, and when the open flow was gaged again with the Pitot tube after the pressure-flow conditions were stable it was found to agree closely with the results of the back-pressure test.

A series of special back-pressure tests was conducted on a gas well in the Shamrock field in western Texas to determine the reliability of back-pressure data under different degrees of flow stabilization. The well was 1,960 feet deep and produced gas through $8\frac{1}{4}$-inch casing set at a depth of 1,805 feet below the surface of the ground. The stabilized shut-in pressure at the wellhead before a test on September 1, 1930 was 416 pounds per square inch gage compared with a shut-in pressure of 397 pounds per square inch gage observed 1 hour after the back-pressure test was completed. Observations were made for a low delivery rate (through a $\frac{1}{2}$-inch orifice in the critical-flow prover), and the working pressures at the wellhead and delivery rates were observed at periods of 2, 5, 15, 30, and 60 minutes of pressure-flow stabilization. Observations then were made of the "build-up" in shut-in pressure corresponding to different periods of elapsed time. Similar readings were obtained for three other delivery rates (through $\frac{3}{4}$-, $1\frac{1}{8}$-, and $1\frac{3}{8}$-inch orifices), allowing the stabilized back pressures at the well to decrease and the stabilized rate of flow to increase for each consecutive set of observations. Finally, data were obtained for three other delivery rates (through $1\frac{1}{4}$-, $\frac{7}{8}$-, and $\frac{5}{8}$-inch orifices) allowing the stabilized back pressure to increase and the stabilized rate of flow to decrease



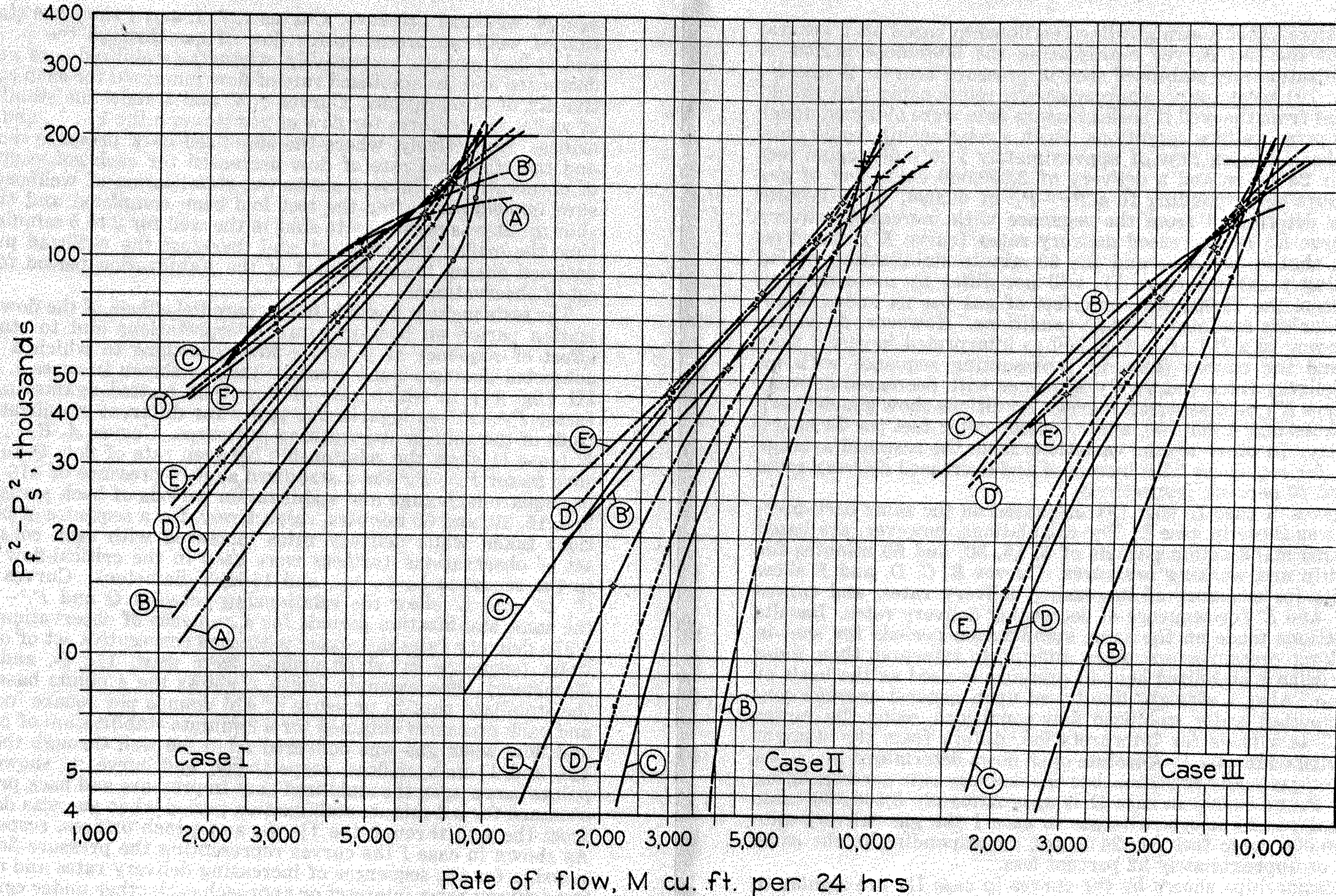
1-7 inclusive, Sequence in which orifices were used in back pressure test
8 - Pressure stabilization when well was shut in after back pressure test

FIGURE 18.—Behavior of well-head pressures during back-pressure test on a gas well subject to slow stabilization of pressure-flow conditions. (Well tested September, 1930; same well as illustrated in figures 19, 20, and 21)

for each consecutive set of observations. The behavior of the well-head pressure after the well was opened through each of the orifices and after the flow test was completed when the well had been shut in is shown graphically in figure 18, in which time is plotted against wellhead pressure. Curves *1, 2, 3,* and *4* show the stabilization of wellhead pressures for flow of gas through the ½-, ¾-, 1⅛-, and 1⅜-inch orifices, respectively, where the stabilized back pressure decreased and the stabilized rate of flow increased for each consecutive set of observations. Curves *5, 6,* and *7* show the stabilization of wellhead pressures for flow of gas through the 1¼-, ⅞-, and ⅝-inch orifices, respectively, where the stabilized back pressure increased and the stabilized rate of flow decreased for each consecutive set of observations. Curve *8* shows the stabilization of wellhead pressure immediately after the test had been completed and the well shut in. It was necessary to shut in the well for 2 to 5 minutes each time the orifice was changed, and therefore the wellhead pressure declined during the early part of the stabilization period for each set of observations.

The tests make it possible to compare the effects of the flow stabilization period on back-pressure interpretations and to study the effect of sequence of pressure-flow conditions to which a well is subjected during a back-pressure test, as shown in cases I, II, and III (fig. 19) in which rate of flow Q is plotted against pressure factor $P_f^2-P_s^2$ on logarithmic paper for different stabilization periods of the shut-in and working pressures. Curves A, B, C, D, and E (case I) show the relationship between rate of flow Q and pressure factor $P_f^2-P_s^2$ for a stabilized shut-in pressure of 416 pounds per square inch gage and stabilization periods of back pressures of 2, 5, 15, 30, and 60 minutes, respectively, for a sequence of observations taken while delivery rates increased with each consecutive set of observations (orifices were used in the critical-flow prover in the sequence ½-, ¾-, 1⅛-, and 1⅜-inch diameter). Curves A', B', C', D', and E' show the relationship between Q and $P_f^2-P_s^2$ for the same stabilization periods for a sequence of observations taken while delivery rates decreased with each consecutive set of observations (sequence in which orifices were used, 1¼-, ⅞-, and ⅝-inch diameters). For example, curve A shows the 4 points based upon the stabilized shut-in pressure of 416 pounds per square inch gage and back pressures obtained for a 2-minute stabilization of pressure and flow when gas was delivered from the well through the ½-, ¾-, 1⅛-, and 1⅜-inch orifices, respectively, and curve A' shows the 3 points based upon the stabilized shut-in pressure and back pressures obtained for a 2-minute stabilization period when gas was delivered from the well through the 1¼-, ⅞-, and ⅝-inch orifices, respectively. As shown in case *I* the curves representing the pressure-flow relationship for the sequences of increasing delivery rates and decreasing delivery rates intersect or approach each other under conditions of high values of the pressure factor $P_f^2-P_s^2$ but vary widely from each other at low delivery rates and low values of $P_f^2-P_s^2$.

The curves representing the different sequences of back-pressure data for each period of flow stabilization show that as the period of flow stabilization is increased the curves approach each other more closely, and the plotted relationship becomes more consistent. It is logical to assume, from results of numerous back-pressure tests on gas wells not subject to long periods of flow stabilization, that the same relationship between the delivery rates and the pressure factor $P_f^2-P_s^2$ exists under stabilized flow conditions, regardless of pressure-flow sequences (see example III, fig. 22). Accordingly,



A,B,C,D and E - Stabilization periods of 2,5,15,30 and 60 minutes for sequence of increasing delivery rates.
(Gas deliveries regulated and measured with ½-, ¾-, 1⅛- and 1⅜-inch orifices in critical-flow prover in sequence)
A′,B′,C′,D′ and E′ - Stabilization periods of 2,5,15,30 and 60 minutes for sequence of decreasing delivery rates.
(Gas deliveries regulated and measured with 1¼-, ⅞- and ⅝-inch orifices in critical-flow prover in sequence)

Case I, Based on stabilized shut-in pressure
Case II, Based on same stabilization periods of shut-in and working pressures
Case III, Based on shut-in pressure observed one hour after completing back-pressure test

FIGURE 19.—Effect of slow stabilization of pressure-flow conditions and of sequence in which data are observed on interpretation of back-pressure data. (Well tested September, 1930; same well as illustrated in figures 18, 20, and 21)

it is considered that a straight-line relationship based on a general average of the two curves representing the 60-minute period of flow stabilization and stabilized shut-in pressure (curves *E* and *E′*, case I, fig. 19) most nearly approaches the relationship that should be expected from the well if back-pressure data were obtained under stabilized pressure-flow conditions. Such a relationship would indicate an absolute open flow of approximately 11,000,000 cubic feet of gas per 24 hours and a delivery of 2,000,000 cubic feet of gas per 24 hours corresponding to a $P_f^2 - P_s^2$ of 40,000. The absolute open flow determined from the sequence with increased delivery rates (curve *E*) or decreased delivery rates (curve *E′*), based on stabilized shut-in pressure and the 60-minute stabilization period for working pressures (case I), will not differ by more than 10 percent from the 11,000,000 cubic feet of gas per 24 hours established under the assumed average conditions. However, deliveries corresponding to a $P_f^2 - P_s^2$ of 40,000 as interpreted in case I vary widely, and the curves (case I) representing sequence with increased delivery rates (curve *E*), sequence with decreased delivery rates (curve *E′*), and assumed average conditions show gas-delivery rates of 2,600,000, 1,600,000, and 2,000,000 cubic feet per 24 hours, respectively. In other words, variations from the assumed average condition for sequences with increased and decreased delivery rates are 30 and 20 percent, respectively.

The curves of case II (fig. 19) are based on the same back-pressure tests as those in case I. The calculations, however, are based on the same stabilization periods of 5, 15, 30, and 60 minutes for both shut-in and working pressures. Curves *B*, *C*, *D*, and *E* show the results for sequence of increasing delivery rates, and curves *B′*, *C′*, *D′*, and *E′* for sequence of decreasing delivery rates. Results of calculations made on the same stabilization periods for shut-in and working pressures are more difficult to interpret than those obtained when a stabilized shut-in pressure is used as the basis of calculation. Also, a straight line based upon general average conditions expected under stabilized flow conditions, using the curves in case II as a basis for interpretation, differs from the straight line established in case I. Absolute open flows determined in cases I and II are practically the same, but the delivery rate corresponding to a $P_f^2 - P_s^2$ of 40,000 in case II is approximately 3,100,000 cubic feet of gas per 24 hours, whereas in case I the gas-delivery rate was 2,000,000 cubic feet per 24 hours, corresponding to the same $P_f^2 - P_s^2$, or approximately 32 percent less.

The relationships shown by the curves in case III are similar to those in cases I and II, except that the calculations for the curves of case III are based on a shut-in pressure of 397 pounds per square inch gage, obtained 1 hour after the back-pressure test was completed. The average straight-line relationship established in the same manner for case III as for cases I and II indicates an absolute open-flow volume of approximately 11,000,000 cubic feet of gas per 24 hours, which is the same as in case I. However, the delivery rate at a $P_f^2 - P_s^2$ of 40,000 obtained from the average relationship is approximately 3,000,000 cubic feet of gas per 24 hours compared with 2,000,000 and 3,100,000 cubic feet per 24 hours for cases I and II, respectively.

A second series of back-pressure tests was made on this well in November 1933. On November 18 back-pressure data were obtained for stabilization periods of 3, 5, 15, 30, and 60 minutes, respectively, for a sequence of observations taken while delivery rates increased with each consecutive set of observations (orifices were used in critical-flow prover in the sequence $\frac{5}{8}$-, $\frac{3}{4}$-, $\frac{7}{8}$-, and 1-inch diameters). The stabilized shut-in pressure on the well gaged just before the flow tests was 382 pounds per square inch gage. The behavior of the wellhead pressure after the well was opened through each of the orifices is shown by curves *1, 2, 3,* and *4* (fig. 20). The

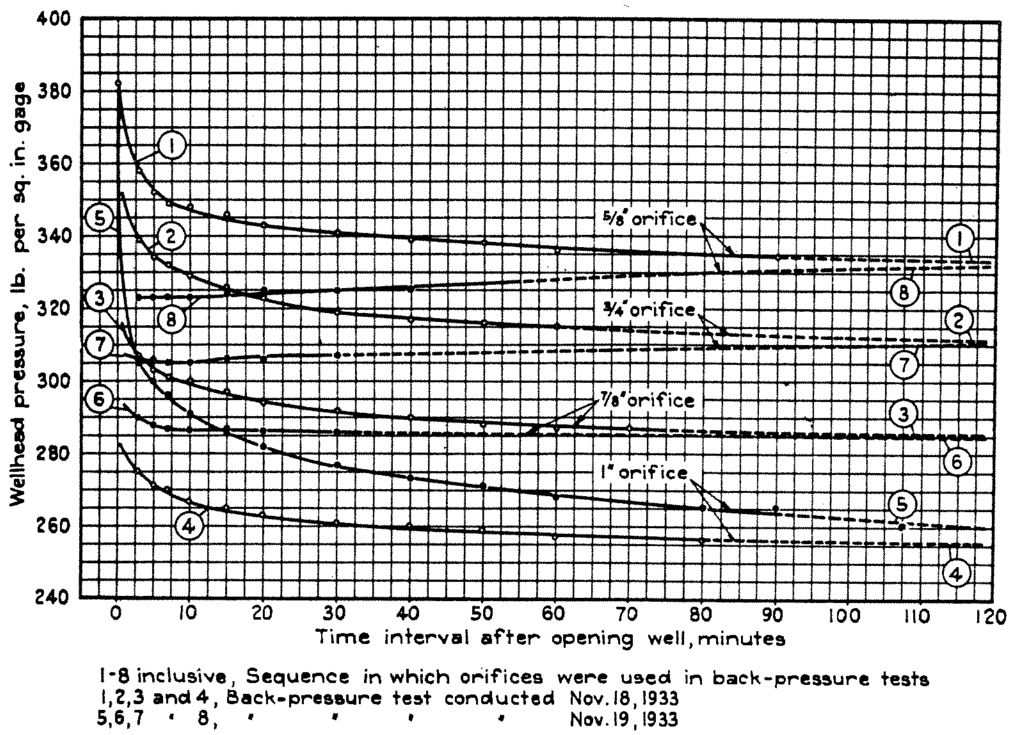
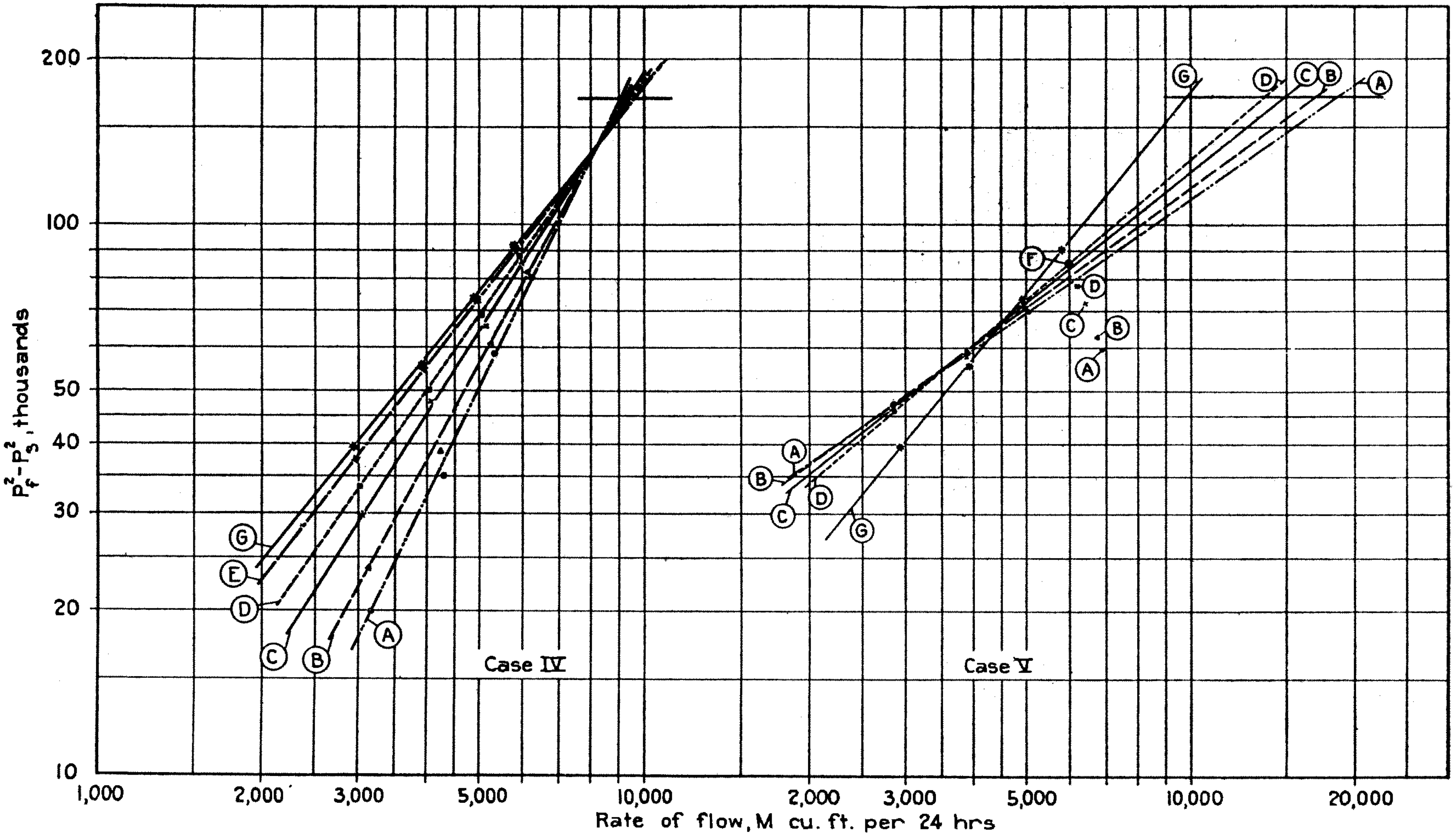


FIGURE 20.—Behavior of well-head pressures during back-pressure test on a gas well subject to slow stabilization of pressure-flow conditions. (Well tested November 1933; same well as illustrated in figures 18, 19, and 21)

relationships between rate of flow Q and pressure factor $P_f^2 - P_s^2$ for stabilization periods of 3, 5, 15, 30, and 60 minutes are shown by curves *A, B, C, D,* and *E,* case IV (fig. 21) and are based on the stabilized shut-in pressure of 382 pounds per square inch gage.

On November 19, after the well had been closed in for approximately 18 hours, additional back-pressure data were obtained for stabilization periods of 3, 5, 15, and 30 minutes, respectively, for a sequence of observations taken while delivery rates decreased with each consecutive set of observations (orifices were used in the critical-flow prover in the sequence 1-, $\frac{7}{8}$-, $\frac{3}{4}$-, and $\frac{5}{8}$-inch diameters). The stabilized shut-in pressure on the well gaged before the test was 382 pounds per square inch gage. The behavior of the wellhead pressure after the well was opened through each of the orifices is shown graphically by curves *5, 6, 7,* and *8* (fig. 20). The relationships between rate of flow Q and pressure factor $P_f^2 - P_s^2$ for the stabilization periods of 3, 5, 15, and 30 minutes are shown



Cases IV and V, Magnitude of flow rate increasing and decreasing in test series, respectively.
Stabilization periods for working pressures, A, 3 min; B, 5 min; C, 15 min; D, 30 min; E, 60 min; F, 90 min., initial flow only,
G, Based on interpreted stabilized pressure-flow conditions (See fig. 20)

FIGURE 21.—Effect of slow stabilization of pressure-flow conditions and of sequence in which data are observed, on interpretation of back-pressure data. (Well tested November 1933; same well as illustrated in figures 18, 19, and 20)

by curves *A, B, C,* and *D,* case V (fig. 21) and are based on the stabilized shut-in pressure of 382 pounds per square inch gage. The data for the gas deliveries through the 1-inch orifice or the initial operating condition of the test series, were supplemented by one delivery rate, and the corresponding back-pressure was observed after a stabilization period of 90 minutes (see *F,* case V, fig. 21).

Comparison of the curves in figures 18 and 20 shows that there was little change in the stabilization characteristic of the well and the relationship of the pressure-flow conditions for a series of delivery rates of the same sequence (increasing or decreasing) during the interval of approximately 3 years between the two series of back-pressure tests.

An average straight line can be determined from the relationships shown by curves *A, B, C,* and *D,* cases IV and V (fig. 21) that will define approximately the relationship between rate of flow Q and pressure factor $P_f^2-P_s^2$, representative of stabilized flow conditions, similar to the analyses made from figure 19. However, since the time-pressure relationships shown in figure 20 had been established for appreciable lengths of time for sequences of observations with increasing and decreasing delivery rates on the same sizes of orifices in the critical-flow prover the curves showing the relationships were extended and the following stabilized wellhead pressures were interpreted.

Sequence during which delivery rates increase with each consecutive set of observations			Sequence during which delivery rates decrease with each consecutive set of observations		
Curve	Size of orifice, in.	Stabilized pressure at wellhead, lb. per sq. in. gage	Curve	Size of orifice, in.	Stabilized pressure at wellhead, lb. per sq. in. gage
1..........	5/8	333	5..........	1	256
2..........	3/4	311	6..........	7/8	284
3..........	7/8	284	7..........	3/4	311
4..........	1	256	8..........	5/8	333

In this well there was virtually no pressure drop between the pressure tap in the master gate on the casing and the pressure tap on the critical-flow prover, so the pressure factor $P_f^2-P_s^2$, and the corresponding rates of gas delivery were calculated from the above data. The plotted relationship between Q and $P_f^2-P_s^2$ representative of approximately stabilized pressure-flow conditions is shown by curve *G,* cases IV and V (fig. 21).

In conducting back-pressure tests on gas wells the wells should be closed in long enough before the test for the wellhead pressure to become stabilized so that a standardized basis with which to interpret the results of the back-pressure tests can be obtained. Often use of the same pressure gage for determining the shut-in and operating pressures improves the reliability of the pressure data. These practices are especially desirable in testing gas wells characterized by slow pressure-flow stabilization; otherwise, conditions of apparent stabilization for short intervals following a change in the regulation of a well, illustrated by the 2-, 3-, and 4-minute observations (curve *7*, fig. 18) and the 3-, 5-, 7-, and 10-minute observations (curve *8*, fig. 20) may result in failure to recognize the slow stabilization characteristic of the well. The curves in figures 18 and 20 also show the error in pressure which can be caused by failing to recognize a temporary stable pressure-flow condition when the well-control equipment is manipulated. The effect of the pressure error on the interpretation of the back-pressure data is shown by comparing curves *A*, *B*, *C*, and *D* with curve *G* (case V, fig. 21).

The curves in figure 20 indicate an appreciable variation of wellhead pressure when pressure-flow conditions were being stabilized, depending upon the sequence in which back-pressure observations were made, the size of orifice being used in the critical-flow prover to regulate and measure the gas deliveries, the time during which pressure-flow conditions were being stabilized, and the operating condition of the well just before the back-pressure observations. For example, curve *5* shows a wellhead pressure of 291 pounds per square inch gage after a stabilization period of 10 minutes with gas flowing through the 1-inch orifice compared with 286 pounds per square inch after the same stabilization period for flow of gas through the $\frac{7}{8}$-inch orifice, as shown in curve *6*, whereas the interpreted stabilized wellhead pressures for curves *5* and *6* are 256 and 284 pounds per square inch gage, respectively. Curves *2* and *8* for flows through the $\frac{3}{4}$- and $\frac{5}{8}$-inch orifices, respectively, show wellhead pressures of 329 and 323 pounds per square inch gage, respectively, after stabilization periods of 10 minutes compared with interpreted stabilized wellhead pressures of 311 and 333 pounds per square inch gage, respectively. Curve *5*, which shows the rate of stabilization of wellhead pressure when the gas deliveries were regulated and measured through the 1-inch orifice and which represents the initial flow condition of a series of observations with the sequence of delivery rates decreasing for each consecutive set of observations, differs in character from curves *6*, *7*, and *8*, which show the rate of stabilization of wellhead pressures for gas deliveries through the $\frac{7}{8}$-, $\frac{3}{4}$-, and $\frac{5}{8}$-inch orifices, respectively.

The well had been shut in and the shut-in pressure was stabilized just before the observations shown by curve *5*. The points on curve *5* were used to calculate the initial points (maximum delivery rates of the test series) showing the relationships between Q and $P_f^2-P_s^2$ for stabilization periods of *3*, *5*, *15*, and *30* minutes for curves *A*, *B*, *C*, and *D*, respectively (fig. 21, case V), and the calculated points apparently were inconsistent with the other observations made during the tests. It is interesting to note that the rate of flow Q and corresponding pressure factor $P_f^2-P_s^2$, obtained for the 90-minute period of flow stabilization, when gas was flowing through the 1-inch orifice (curve *5*, fig. 20), when plotted on the chart in case V (fig. 21) is on curve *D*, which represents a stabilization period of 30 minutes. All of the curves in figures 18, 19, 20, and 21 emphasize the importance of careful analyses of pressure and flow conditions in gas wells characterized by slow stabilization of pressure-flow conditions when back-pressure tests are made and back-pressure data analyzed.

The curves in example I (fig. 22) show the results of a back-pressure test on a gas well and give the relationships between the delivery rate Q and the pressure factor $P_f^2 - P_s^2$ for periods of flow stabilization of 15, 30, 45, 60, and 90 minutes. Calculations are based on a shut-in and stabilized pressure at the wellhead, and the curves indicate that the observations taken for the 90-minute period of stabilization are representative of stabilized pressure-flow conditions. The initial observations correspond to the lowest delivery rate of the test series, and the delivery rates then were increased for each consecutive set of observations.

The curves in example II (fig. 22) of a back-pressure test on another gas well show results similar to those just cited. Observations on the well were made for stabilization periods of 1, 2, 3, 10, and 35 minutes, and the curves indicate that flows were not quite stabilized at the end of 35 minutes.

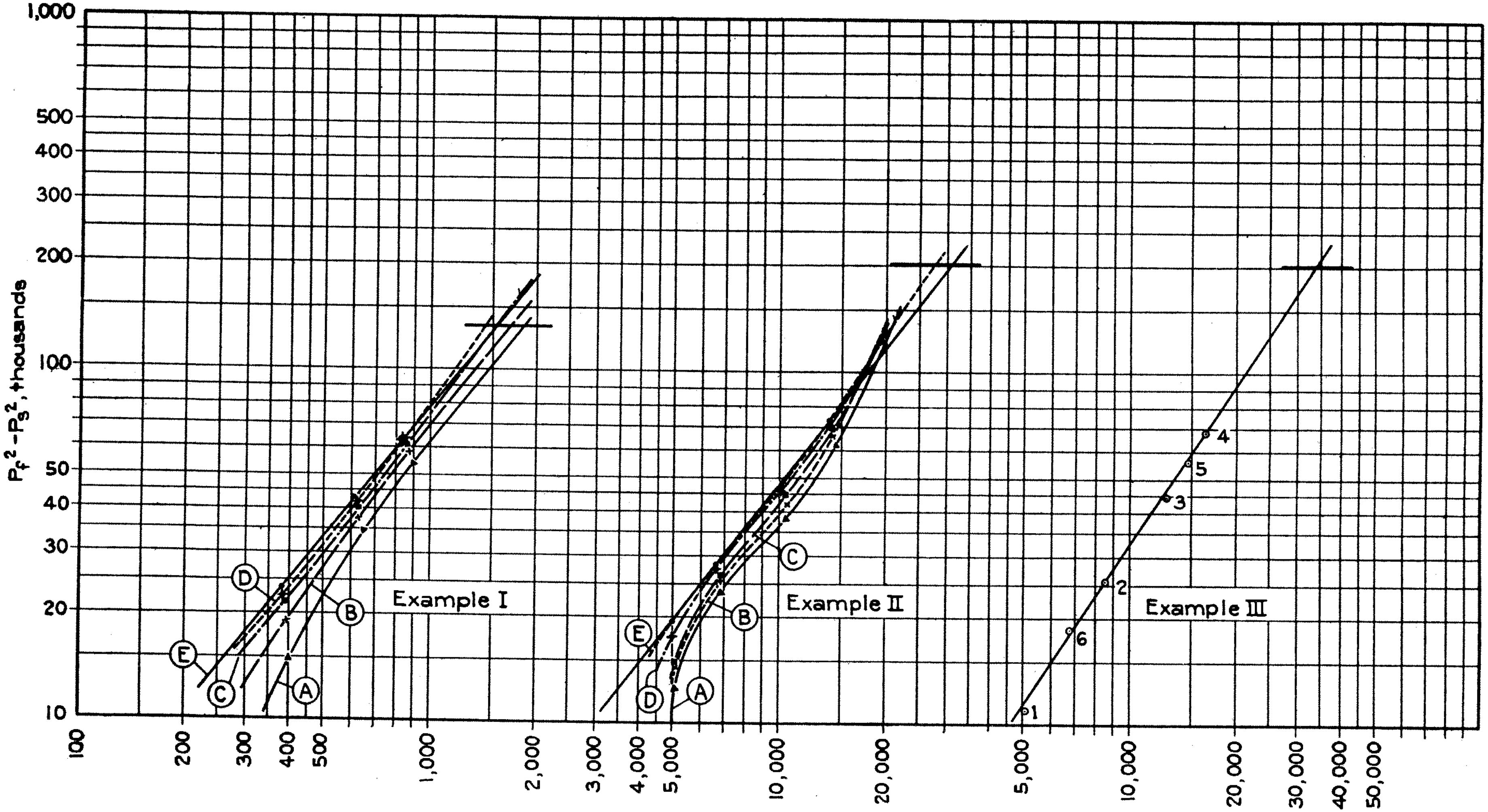
The results of a back-pressure test on still another gas well characterized by slow stabilization of pressure-flow conditions are shown in example III (fig. 22). Observations were made under stabilized pressure-flow conditions with the indicated sequence of each set of observations with respect to delivery rates and pressures. The results of the test stress the fact that the same relationship between delivery rate and pressure factor $P_f^2 - P_s^2$, exists under stabilized pressure-flow conditions, regardless of pressure-flow sequences during a back-pressure test.

Back-pressure tests generally should be conducted under stabilized pressure-flow conditions, and observations should not be taken until there is no further change in the working pressure at the wellhead. This practice is possible at most gas wells. However, as illustrated by figures 19 and 22, some gas wells are subject to a very slow rate of stabilization of pressure-flow conditions after an adjustment of the delivery rate, and it is not always possible to wait for absolute stabilization of conditions in the well. Approximate interpretations of delivery capacities of such wells can be made, however, from observations after limited periods of flow stabilization if the sequences of delivery rates and pressures observed during the back-pressure tests allow comparisons to be made between the results computed for increasing and decreasing rates of flow during series of readings. Average relationships based on such data will give approximate analyses of the delivery capacities of the wells. A definite procedure for making such tests, however, cannot be outlined, because the factors that control production from individual wells vary considerably; but the results of back-pressure tests of the kind illustrated in figures 19 and 22 and others discussed previously in this report can be used as a basis for the interpretation of delivery capacities of gas wells subject to slow pressure-flow stabilization.

VARIATION IN DELIVERY CAPACITIES OF GAS WELLS AT DIFFERENT TIMES IN THEIR PRODUCTIVE LIVES

Results of a study of the factors that influence the flow of gas through porous media already have been discussed,[35] and it has been shown that the relationship between the rate of flow Q and

[35] See discussion under Flow of Gas Through Porous Media and appendix 9 of this report.



Stabilization periods for working pressures,

Example I, A, 15 min.	Example II, A, 1 min.	Example III, Stabilized
B, 30 "	B, 2 "	
C, 45 "	C, 3 "	
D, 60 "	D, 10 "	
E, 90 "	E, 35 "	

Calculations based on stabilized shut-in pressures

FIGURE 22.—Comparison of back-pressure data obtained on gas wells after different periods of pressure ...

the pressure factor $P_a^2 - P_b^2$, where P_a is the absolute pressure at the upstream end of the porous medium and P_b is the absolute pressure at the downstream end, can be expressed, for practical purposes, by the formula,

$$Q = C(P_a^2 - P_b^2)^n.$$

This formula is in the same form as the one used to interpret the results of back-pressure tests on gas wells. The flow equation for gas wells is:

$$Q = C(P_f^2 - P_s^2)^n,$$

where P_f is the shut-in formation pressure and P_s the back pressure at the face of the sand in the well bore.

The tests on the flow of gas through porous media show that such factors as sand porosity, distance of gas flow, volume of sand, and void space affect coefficient C of the flow equation and that the size and character of the sand grains and the permeability of the porous medium affect both coefficient C and exponent n of the flow equation. The flow equation for a particular screened sample of sand packed in a flow tube and having a definite porosity can be determined from a series of experimental tests, and it can be shown that the equation remains the same, regardless of the magnitude of the flowing pressures and the volume of gas passing through the sand. The same principles that hold for the experimental flow tubes would apply to pressure-flow relationships in a gas well if there were no changes in the size of the effective drainage space of the well, in the area of the wall of the well bore in the producing sand, and in the effective porosity and permeability of the sand, and if there were no possibility of channeling and bypassing of gas through the more permeable streaks of the producing stratum.

The results of a number of experiments made to determine the effect of the presence of liquid on gas flow through porous media also have been discussed [36] in this report. Briefly, the tests indicated that saturation of dry sand with liquid materially decreases the permeability of the sand to passage of gas. The effect of liquid in wells on back-pressure data and delivery capacities, the effects of cavings that clog the sand and reduce the rates of flow, and special considerations for wells subject to slow pressure-flow stabilization, have been discussed. There are, therefore, many natural and common factors that tend to change delivery capacities of gas wells at different times in their productive lives.

In addition, one other operating condition of major importance that affects the delivery capacities of gas wells as interpreted from results of back-pressure tests is the " pull " that has been made on the well just prior to the test; in other words, it must be ascertained whether the well has been delivering gas into a pipeline system at an appreciable rate, delivering gas at a fairly low rate, or shut in for some time. The operating conditions of wells in the vicinity of the well that is being studied, both prior to and at the time of the back-pressure test, also affect delivery capacities. In general, back-pressure tests should be conducted under conditions that will reveal operating delivery capacities of gas wells.

[36] See appendix 10.

It is reasonable to assume that if there were no changes in the physical and mechanical conditions of the producing formation and the well bore, coefficient C and exponent n of equation $Q=C(P_f^2-P_s^2)^n$ applying to an individual well would be constant throughout its life regardless of the decrease in the formation pressure P_f resulting from depletion of the gas in the reservoir. Back-pressure tests made at different times in the productive lives of some gas

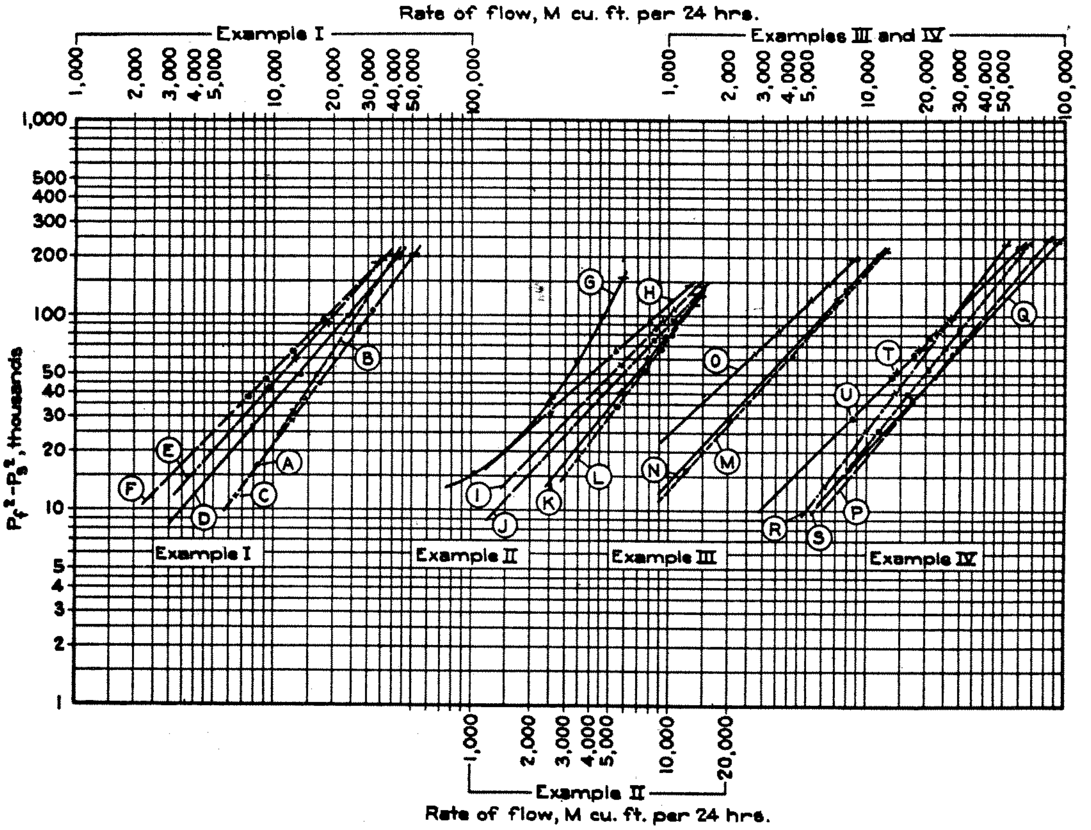


FIGURE 23.—Variation in delivery capacities of gas wells at different times in their productive lives, examples I, II, III, and IV

wells have indicated negligible variations in the producing characteristics of the wells, and the relationships between flow rates Q and pressure factors $P_f^2-P_s^2$ remained virtually the same. When that is true the results of early back-pressure tests can be used as a basis for determining probable deliveries at later dates when the formation pressure is lower, but nevertheless occasional back-pressure tests should be made on all gas wells. Because back-pressure tests conducted at different times in the productive lives of some gas wells indicate the same relationships between Q and

$P_f^2 - P_s^2$ it should not be taken for granted that the relationships will be the same at all times—tests conducted when conditions are different may result in widely varying relationships between Q and $P_f^2 - P_s^2$.

Delivery capacities of gas wells indicated by the results of back-pressure tests conducted at different times in the productive lives of the wells generally change as the reservoir sands become depleted of gas. Decreases in delivery capacities are caused by liquid or cavings in the well bore, and there may be other effects on the delivery

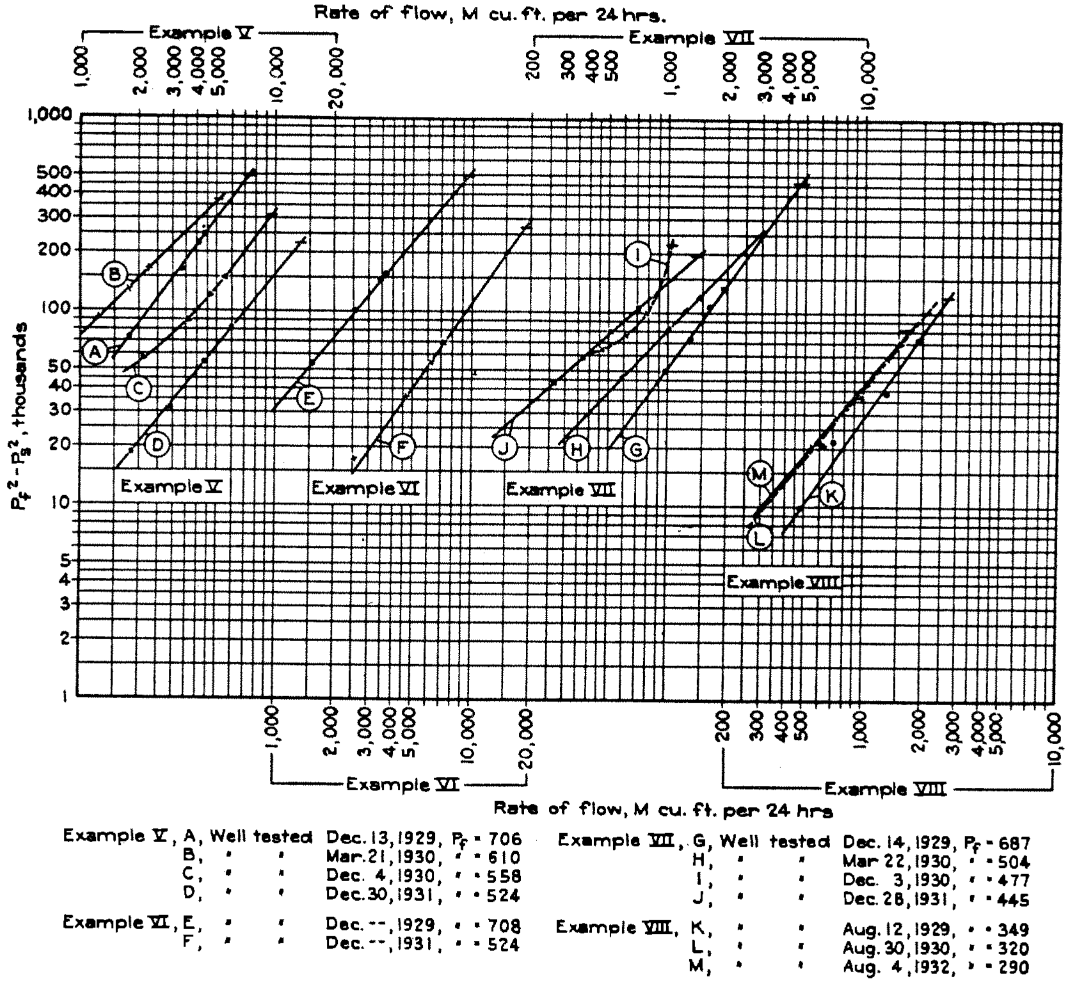


FIGURE 24.—Variation in delivery capacities of gas wells at different times in their productive lives, examples V, VI, VII, and VIII

capacities of gas wells that were not apparent from the studies that could be made during the survey upon which this report is based. However, back-pressure tests frequently suggest that the conditions in a well should be remedied, and in any event the results of back-pressure tests can be used as guides for study and interpretation of conditions in gas wells where the changes during the productive lives of the wells are appreciable and seriously affect normal producing operations. Remedial measures tending to increase the operating efficiency of gas wells often involve a "cut-and-try" procedure, at which time the results of back-pressure tests will reveal the effects of the remedial measures.

Back-pressure tests were made on 21 wells in the Depew field, Oklahoma, 75 wells in the Texas Panhandle, and 32 wells in the Rocky Mountain area, to study variations in delivery capacities that occur during the productive lives of gas wells. In general, the main objective of the studies was to determine variations in delivery capacities under conditions of normal operation, and the tests were conducted on the wells at different times in their productive lives without attempting to analyze the causes of variations in delivery

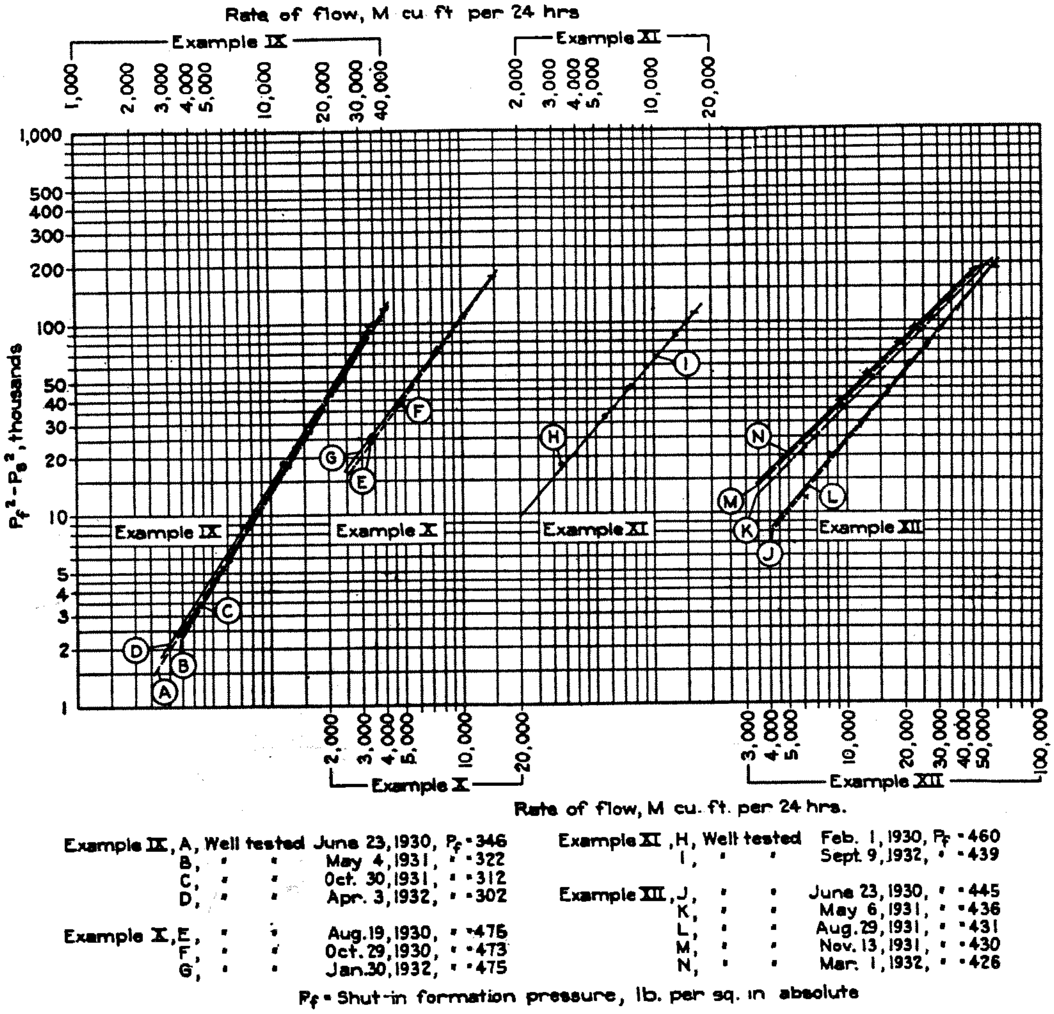


FIGURE 25.—Variation in delivery capacities of gas wells at different times in their productive lives, examples IX, X, XI, and XII

capacities or to apply remedial measures to the wells. Examples shown in figures 23, 24, and 25 give graphic representations of variations in gas-delivery capacities noticed while the back-pressure tests were being made. The gas wells used for the tests are described in table 17, and numerical comparisons of pressure and flow data are shown in table 18.

The results of a series of back-pressure tests on a gas well in the Texas Panhandle field are shown in example I (fig. 23). The first back-pressure test on the well was on June 24, 1930, when the absolute open-flow volume as determined from the plotted relationship was found to be approximately 50,500,000 cubic feet of gas per 24

TABLE 17.—*Data on gas wells, illustrating ability to produce gas at different times in productive life (description of gas wells)*

Well	Formation	Upper gas, ft.	Lower gas, ft.	Depth, ft.	Casing		Remarks
					Size, in.	Set at, ft.	
Example I (fig. 23)	Lime	2,322	2,815	2,815	10	2,047	Texas Panhandle
Example II (fig. 23)	..	1,975	2,240	2,295	10	1,705	Do.
Example III (fig. 23)	..	2,100	2,360	2,360	8¼	2,077	Do.
Example IV (fig. 23)	Lime	2,175	2,639	2,630	10	1,905	Do.
Example V (fig. 24)	Dutcher sand	3,227	..	3,244	6⅝	3,227	Depew field
Example VI (fig. 24)	do.	3,202	..	..	6⅝	..	Do.
Example VII (fig. 24)	do.	3,303	..	..	6⅝	3,116	Do.
Example VIII (fig. 24)	..	1,330	..	..	6⅝	..	Kevin-Sunburst
Example IX (fig. 25)	Lime	2,350	2,715	3,077	10	1,893	Texas Panhandle
Example X (fig. 25)	..	2,919	3,290	3,664	8¼	..	Do.
Example XI (fig. 25)	..	..	..	2,630	8¼	..	Do.
Example XII (fig. 25)	Lime	2,310	2,350	3,305(?)	10	2,035	Do.

TABLE 18.—*Data on gas wells, illustrating ability to produce gas at different times in productive life (pressure and flow data)*

Well	Date of test	Shut-in formation pressure, lb. per sq. in. absolute	Absolute open flow, M cu. ft. per 24 hours	Delivery at high back pressure, M cu. ft. per 24 hours		Remarks
				$P_f^2 - P_s^2$	Q	
Example I (fig. 23)	June 24, 1930	452	50,500	30,000	10,270	Cavings accumulating between first and second tests. Removed before third test.
	Sept. 29, 1930	449	40,500	30,000	10,200	
	Nov. 13, 1930	449	50,000	30,000	10,270	
	May 1, 1931	441	41,000	30,000	8,700	
	Oct. 12, 1931	437	35,000	30,000	7,100	
	Mar. 24, 1932	433	34,000	30,000	6,000	
Example II (fig. 23)	June 25, 1930	386	5,900	30,000	2,150	No conclusive evidence for explanation of variation.
	July 23, 1931	378	10,270	30,000	2,320	
	Aug. 5, 1931	377	14,000	30,000	3,150	
	Oct. 19, 1931	359	14,000	30,000	3,670	
	Oct. 22, 1931	358	14,200	30,000	4,600	
	May 3, 1932	337	13,500	30,000	5,000	
Example III (fig. 23)	June 23, 1930	460	12,300	30,000	2,180	
	Oct. 19, 1931	458	11,700	30,000	2,020	
	Oct. 22, 1932	440	8,600	30,000	1,220	
Example IV (fig. 23)	June 23, 1930	442	70,000	30,000	15,000	
	Oct. 2, 1930	438	77,000	30,000	14,300	
	May 5, 1931	430	43,500	30,000	11,200	
	Sept. 2, 1931	428	56,000	30,000	13,100	
	Nov. 16, 1931	425	49,000	30,000	9,400	
	Feb. 27, 1932	421	49,000	30,000	9,400	
Example V (fig. 24)	Dec. 13, 1929	706	7,300	80,000	1,900	
	Mar. 21, 1930	610	5,100	80,000	1,900	
	Dec. 4, 1930	558	9,500	80,000	3,200	
	Dec. 30, 1931	524	13,300	80,000	5,800	
Example VI (fig. 24)	Dec., 1929	708	9,500	80,000	2,120	
	Dec., 1931	524	18,500	80,000	8,000	
Example VII (fig. 24)	Dec. 14, 1929	687	4,700	80,000	1,330	
	Mar. 22, 1930	504	2,900	80,000	980	
	Dec. 3, 1930	477	?	80,000	640	
	Dec. 28, 1931	445	1,400	80,000	520	
Example VIII (fig. 24)	Aug. 12, 1929	349	2,700	20,000	780	
	Aug. 30, 1930	320	2,100	20,000	550	
	Aug. 4, 1932	290	1,750	20,000	535	
Example IX (fig. 25)	June 23, 1930	346	39,500	20,000	12,700	
	May 4, 1931	322	36,000	20,000	13,100	
	Oct. 30, 1931	312	33,000	20,000	12,700	
	Apr. 3, 1932	302	31,500	20,000	12,200	
Example X (fig. 25)	Aug. 19, 1930	475	14,500	30,000	3,950	
	Oct. 29, 1930	475	14,500	30,000	3,750	
	Jan. 30, 1932	475	14,500	30,000	3,950	
Example XI (fig. 25)	Feb. 1, 1930	460	16,300	20,000	3,750	
	Sept. 9, 1932	439	14,800	20,000	3,750	
Example XII (fig. 25)	June 23, 1930	445	58,000	30,000	12,000	Cavings accumulating between first and second tests removed before third test.
	May 6, 1931	436	52,000	30,000	8,300	
	Aug. 29, 1931	431	56,000	30,000	12,200	
	Nov. 13, 1931	430	48,000	30,000	7,600	
	Mar. 1, 1932	426	45,000	30,000	7,200	

hours and the shut-in formation pressure was 452 pounds per square inch absolute. The second test was on September 29, 1930 and showed an absolute open-flow volume of approximately 40,500,000 cubic feet of gas per 24 hours—a reduction of approximately 20 percent during the 3-month period corresponding to a decrease in absolute shut-in formation pressure of only about 0.7 percent. It was suspected that cavings had accumulated in the well bore, so the well was blown and a third test made on November 13, 1930. The results of the third test agreed closely with the results of the first test. A fourth back-pressure test was made on May 1, 1931, after the well had produced gas into the pipe-line system throughout the winter.

The decrease in formation pressure between the third and fourth tests was 8 pounds per square inch. The absolute open-flow volume determined from the results of the fourth test was approximately 41,000,000 cubic feet of gas per 24 hours. A fifth test was made on October 12, 1931, when the shut-in formation pressure was 437 pounds per square inch absolute and the absolute open flow approximately 35,000,000 cubic feet of gas per 24 hours. A sixth back-pressure test was made on March 24, 1932, when the shut-in formation pressure was 433 pounds per square inch—a decrease from 452 pounds per square inch from June 1930, or 19 pounds in approximately 21 months. The absolute open flow was about 34,000,000 cubic feet of gas per 24 hours compared with 50,500,000 cubic feet per 24 hours in June 1930—a reduction of approximately 30 percent compared with a decrease of only 4.2 percent in the formation pressure. There was no conclusive evidence during the fourth, fifth, and sixth back-pressure tests that might be used to explain the continual decline in the delivery capacities of the well, but it is suspected that cavings in the well bore caused at least some of the variations shown by the curves in example I.

Delivery rates corresponding to a $P_f^2 - P_s^2$ of 30,000 (back pressure at the sand, 418 pounds per square inch absolute for the first test) as shown in table 18 were practically the same for the first, second, and third tests or approximately 10,270,000 cubic feet of gas per 24 hours. The delivery rate with the same pressure factor for the third test was approximately 8,700,000 cubic feet of gas per 24 hours—a decrease of approximately 14.7 percent. Delivery rates for the fifth and sixth tests were 7,100,000 and 6,000,000 cubic feet of gas per 24 hours, respectively, representing decreases of approximately 30.9 and 41.6 percent, respectively, from the delivery rate shown by the first test.

The results of a similar series of back-pressure tests on another gas well in the Texas Panhandle field are shown in example XII (fig. 25). Cavings in the well bore caused noticeable decreases in delivery capacities between the first and second tests. After the well was blown a third test showed increased delivery capacities that agree closely with those of the first test.

The results of back-pressure tests on other gas wells in the Texas Panhandle area showed variations in delivery capacities during productive lives of the wells, as illustrated graphically in examples II, III, and IV (fig. 23). The results of the tests (example II) indicate gradual increases in delivery capacities of the well at different times during a period of almost two years. The delivery capacity corresponding to a $P_f^2 - P_s^2$ of 30,000 apparently increased from 2,150,000 to 5,000,000 cubic feet of gas per 24 hours (approximately 133 percent) from June 25, 1930 to May 3, 1932. The shut-in formation pressure during this time decreased from 386 to 337 pounds per square inch (approximately 13 percent). Results of the back-pressure tests illustrated in example III indicate small decreases in delivery capacities during 4 months of the summer and early fall seasons while the shut-in formation pressure decreased only 2 pounds per square inch. The results of a third test conducted about 1 year later, after enough gas had been withdrawn from the well to reduce the shut-in pressure from 458 to 440 pounds per square inch, indicate an appreciable decline in gas-delivery capacities of the well.

Back-pressure tests (example IV) show gradual decreases in delivery capacities at different times during a period of about 20 months. The results from the first two tests, conducted during the summer and early fall of 1930, indicate virtually the same relationship between Q and $P_f^2 - P_s^2$. The third test was made 7 months later than the second test, after the well had produced gas during the winter and the shut-in formation pressure had decreased from 438 to 430 pounds per square inch. The results of the test indicate substantial decreases in delivery capacities. The results of a fourth test on September 2, 1931, or 4 months after the third test, is representative of changes in the well during the summer of 1931 and shows increases in delivery capacities compared with results of the third test. The results of tests on November 16, 1931, and February 27, 1932, gave virtually identical pressure-flow relationships and indicated further decreases in delivery capacities, especially under high back pressures.

The results of a series of back-pressure tests on three gas wells in the Depew gas field, Oklahoma, are shown in examples V, VI, and VII (fig. 24). Variations of delivery capacities at different times in the productive lives of the wells undoubtedly were due mainly to the presence of liquid in the well bore and in the producing formation. The first test (example V) was on December 13, 1929, when the shut-in formation pressure was 706 pounds per square inch absolute and the absolute open flow interpreted from the plotted relationship 7,300,000 cubic feet of gas per 24 hours. The second test was on March 21, 1930, when it was found that the shut-in formation pressure was 610 pounds per square inch absolute and the absolute open flow 5,100,000 cubic feet of gas per 24 hours. The third test was on December 4, 1930, by which time the shut-in formation pressure had decreased to 558 pounds per square inch, and the absolute open flow apparently had increased to 9,500,000 cubic feet of gas per 24 hours. Results of the fourth test, about 1 year after the third test, show a further decrease in the shut-in formation pressure to 524 pounds per square inch and an indicated increase in absolute open flow to 13,300,000 cubic feet of gas per 24 hours. Variation of delivery capacities at different times in the productive life of a well under conditions of high back pressure are shown in example V (fig. 24) and in table 18. Delivery rates corresponding to a $P_f^2 - P_s^2$ of 80,000 for the first, second, third, and fourth tests are 1,900,000, 1,100,000, 3,200,000, and 5,800,000 cubic feet per 24 hours, respectively, giving a maximum delivery range under this pressure condition equivalent to 80 percent of that obtained from the fourth test.

Results of two back-pressure tests on another gas well in the Depew field in December 1929 and December 1931 are shown in example VI (fig. 24). It was found that the formation pressure had decreased from 708 to 524 pounds per square inch absolute during the 2-year period while the delivery capacity of the well, corresponding to a $P_f^2–P_s^2$ of 80,000, had increased from 2,120,000 to 8,000,000 cubic feet of gas per 24 hours. Results of back-pressure tests on a third well in the Depew field, as illustrated in example VII, indicate appreciable decreases in delivery capacities of the well each time a test was conducted. Results of back-pressure tests on December 14, 1929, March 22, 1930, December 3, 1930, and December 28, 1931, gave shut-in formation pressures of 687, 504, 477, and 445 pounds per square inch absolute and delivery capacities corresponding to a $P^2{}_f–P_s^2$ of 80,000 of 1,330,000, 980,000, 640,000, and 450,000 cubic feet of gas per 24 hours, respectively.

Results of back-pressure tests shown in examples V, VI, and VII (fig. 24) are given mainly to emphasize possible variations in delivery capacities of gas wells that can be expected if the wells are operating under conditions similar to those of the Depew gas field. In general, comparison of delivery capacities under operating-pressure conditions probably is a better basis for studying gas-well behavior than using interpreted values of absolute open flow.

Results of a series of back-pressure tests on a gas well in the Kevin-Sunburst field, Montana, are shown in example VIII (fig. 24). The first test was on August 12, 1929, when the shut-in formation pressure was 349 pounds per square inch absolute. The second test was on August 30, 1930, when it was found that the shut-in formation pressure had decreased 29 pounds per square inch or to 320 pounds per square inch absolute while the delivery capacity of the well, corresponding to a $P_f^2-P_s^2$ of 20,000, had decreased from 780,000 to 550,000 cubic feet of gas per 24 hours. A third test, 2 years after the second, gave results that agreed closely with those of the second test, although the shut-in formation pressure had decreased to 290 pounds per square inch absolute.

Results of back-pressure tests indicating no appreciable changes in producing characteristics of the wells over considerable periods of time are shown in examples IX, X, and XI (fig. 25). Delivery capacities of the well (example IX), corresponding to different values of $P_f^2-P_s^2$ as interpreted from tests made on June 23, 1930, May 4, 1931, October 30, 1931, and April 3, 1932, were virtually the same, although there was a decrease in shut-in formation pressure of 44 pounds, or from 346 to 302 pounds per square inch absolute during the 21-month period. In example X the shut-in formation pressure of the well remained virtually constant during the 18-month period represented by tests on August 19, 1930, October 29, 1930, and January 30, 1932. Delivery capacities indicated by results of the tests agreed closely. In example XI the formation pressure decreased from 460 to 439 pounds per square inch absolute during approximately 19 months, but the results of tests on

February 1, 1930, and September 9, 1932, indicated close agreement between the pressure-flow relationships.

The fact that results of several back-pressure tests at different times in the productive life of a gas well show close agreement between pressure-flow relationships established by the tests does not guarantee necessarily that the producing characteristics are always the same. This is illustrated by example XII (fig. 25). The pressure-flow relationship established by the third back-pressure test on the well (August 29, 1931) virtually agreed with the relationship established by the first test, on June 23, 1930, after cavings had been removed from the well bore although the second test, May 6, 1931, had indicated a reduction in capacity. The results of tests on November 13, 1931, and on March 1, 1932, showed that there were further appreciable decreases in delivery capacities of the well.

Results of back-pressure tests illustrated in the 12 examples given in figures 23, 24, and 25 are representative of gas wells operating under different conditions and indicate that changes usually occur in delivery capacities at different times in the productive life of gas wells, due to such natural causes as liquid in the well bore and in the producing formation, cavings in the well bore, clogging of sand, changes in effective drainage zone with depletion, changes in permeability of the sand, and channeling in the sand. Therefore a definite relationship between delivery rate Q and pressure factor $P_f^2-P_s^2$ cannot be established from one back-pressure test which can be made to apply rigidly for interpretation of future operations of gas wells under all operating conditions. Often, however, thorough understanding of the characteristics of an individual gas well and the conditions under which it is operated permits interpretation of back-pressure data so that relationships can be established which will be applicable to most efficient operating conditions. Such interpretation of back-pressure data and consideration of the possibilities of factors that can change producing characteristics permit using back-pressure data from one test or from a series of tests to forecast future conditions of operation.

A series of curves expressing graphically the relationship between absolute open flow of a gas well expressed as a percent of basic absolute open flow and the absolute formation pressure in the sand expressed as a percent of basic absolute formation pressure is shown in figure 26. The decline of absolute open flow with decline in formation pressure is given for different values of exponent n. For example, assume that the results of a back-pressure test on a gas well gave a shut-in formation pressure of 800 pounds per square inch absolute and an absolute open-flow volume of 60,000,000 cubic feet of gas per 24 hours and that the exponent n of the flow equation is 0.9. If there is no change in the character of the sand or the character of gas flow through the sand and the same relationship between Q and $P_f^2-P_s^2$ is applicable the absolute open flow of the well will be 36,000,000 cubic feet of gas per 24 hours when the formation pressure has declined to 600 pounds per square inch absolute. The formation pressure of 600 pounds per square inch is 75 percent of the basic formation pressure of 800 pounds per square inch, which on the curve for an n of 0.9 (fig. 26) corresponds to an absolute open flow of 60 percent of the basic absolute open-flow volume of 60,000,000 cubic feet per 24 hours. The absolute open flow corresponding to a formation pressure of 600 pounds per square inch is therefore 36,000,000 cubic feet of gas per 24 hours.

The curves in figure 26 apply strictly to conditions where there is no change in the producing characteristic of a gas well as expressed by the formula, $Q=C(P_f^2-P_s^2)^n$ and this condition is not always found in gas wells. However, when the curves are used in

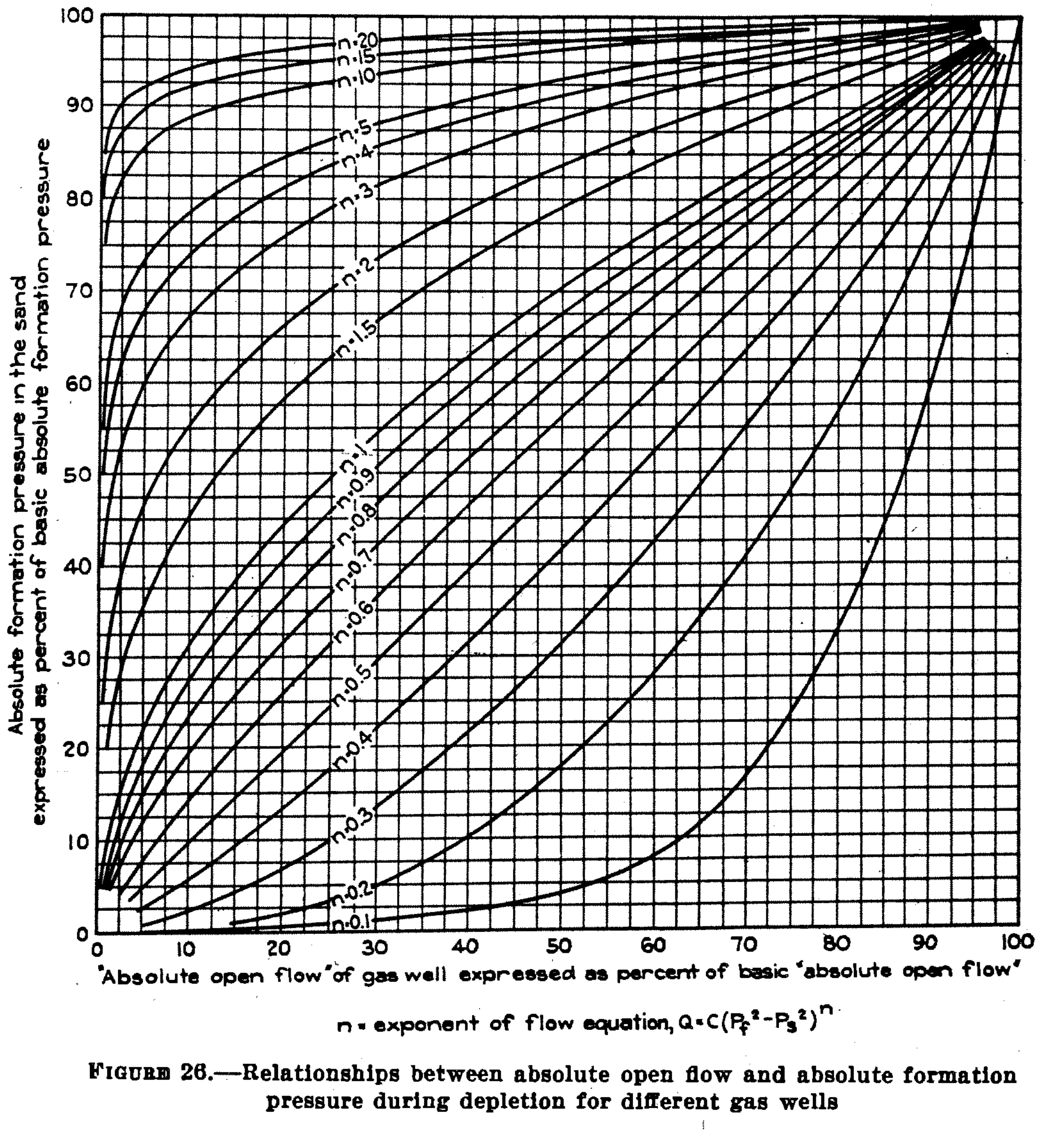


FIGURE 26.—Relationships between absolute open flow and absolute formation pressure during depletion for different gas wells

combination with results of a series of back-pressure tests and with the knowledge of the manner in which different factors influence certain gas wells they will be found helpful in solving many gas-production problems, such as forecasting drilling requirements, estimating future production rates, and planning compressor and pipeline installations. However, in using the data for such studies the back-pressure tests should be conducted under conditions representative of those under which gas wells operate. A measure of delivery capacities which includes the range of deliveries of gas that may be withdrawn from the well under peak load conditions and which is obtained after a period of relatively heavy withdrawals of gas from the well and during the continued abnormal withdrawal of gas from other wells producing from the common reservoir usually will give a much better basis for studying the well from an operating standpoint than will be obtained from back-pressure tests conducted under conditions beyond the commercial operating range of the well.

ACID TREATING OF GAS WELLS

Oil wells producing from formations composed largely of lime or chalk rock or containing calcareous materials have been treated successfully with acid to increase the rate of oil recovery in many areas. The use of acid to increase the delivery capacities of gas wells producing from calcareous formations has been less general and of more recent application. Enough data are not now available to permit the formulation of general conclusions regarding the use of acid and the effect of acid treatment on gas availability; however, the results obtained in the Monroe field, La., are of considerable interest.

During 1933 more than 100 wells in the Monroe field were treated with acid. The wells produce from a formation known as the Monroe gas rock, which is approximately 2,100 feet below the surface of the ground. This formation is composed largely of chalk or calcareous rock and generally was penetrated 25 to 40 feet by the various wells. Most of the wells treated with acid were relatively free from water entry and had not been subject to abnormal decline in delivery capacity. The casing (gas string) was landed not more than 50 feet above the producing formation in most of the wells and was cemented with 100 sacks of cement. Since the wells are equipped with perforated liners and strings of 1¼-inch tubing extending the full depth of the holes through which gas deliveries normally are made it was assumed that the well bores were relatively free from cavings or accumulated cuttings from the reservoir.

The wells were treated with charges of 1,000 gallons of solution containing approximately 16 percent by weight of hydrochloric acid. The solution also contained an inhibitor or agent which retarded the reaction of the acid with the steel tubing, liner, and casing. The equipment used for treating the wells with acid was mounted on two trucks and consisted essentially of a tank, a liquid pump, and a gas compressor.

The general procedure in treating a well with acid was as follows: The shut-in pressure and the open-flow delivery of the well were gaged, and after being open-flowed the well was shut in. Delivery of the charge of the solution to the well was begun after the discharge of the acid pump was connected to the tubing head. The solution was pumped into the tubing until the pressure due to the weight of the column of the solution in the tubing exceeded the well pressure. The pump then was by-passed, and the remainder of the charge of solution was siphoned into the well. Gas from the gathering system then was pumped into the tubing with the compressor. The injection of gas was continued until the pressure on the well was 30 or 40 pounds per square inch greater than the observed shut-in wellhead pressure. The well then was shut in and after remaining closed 4 days, it was "blown" through the tubing from time to time until the stream of gas being discharged to the atmosphere indicated that the residue resulting from the chemical reaction of the acid on the formation had been removed from the well, after which the shut-in pressure and open-flow volume were gaged.

Back-pressure tests were made on one well before and after it was treated with acid. The well was completed with 6-inch casing set 2,064 feet below the surface of the ground. The top of the producing stratum in the well was found to be 2,093 feet deep, and the well was completed at a total depth of 2,131 feet. Well equipment included 88 feet of blank and perforated 4½-inch liner and a string of 1¼-inch tubing, which was packed off at the wellhead. The specific gravity of the gas produced from the well during the period included by the tests was approximately 0.59 (air=1.00). The first back-pressure test was made on September 19, 1933, when the shut-in pressure at the wellhead was 659 pounds per square inch gage. The well was treated with acid on September 20, 1933. The second

TABLE 19.—*Results of back-pressure test on a gas well to show effect of acid treatment on delivery capacities*

Date of Test	P_f, lb. per sq. in. abs.	P_s, lb. per sq. in. abs.	$P_f^2 - P_s^2$, thousands	Rate of flow, M cu. ft. per 24 hours
Sept. 19, 1933.....	704	638	89	1,936
	..	583	156	3,166
	..	462	283	5,570
	..	335	384	7,120
	..	246	435	7,960
Oct. 7, 1933.......	704	664	55	2,006
	..	615	118	5,145
	..	534	211	8,640
	..	451	293	11,670
Mar. 1, 1934......	674	644	39.6	1,940
	..	616	74.8	3,315
	..	546	156.2	6,540
	..	465	238.1	9,590

test was made on October 7, 1933. The results of the tests are shown in table 19, and a graphic comparison of the delivery capacities of the well at the time of the two tests is shown in curves *A* and *B*, figure 27. The delivery capacity of the well throughout the range included by the tests was increased approximately 106 percent after the wells were treated with acid, and the change was reflected largely in factor *C* of the equation for flow, $Q=C(P_f^2-P_s^2)^n$ (curves *A* and *B*, fig. 27).

The permanence of changes in delivery capacities of gas wells due to treatment with acid has not been established definitely; a comparison of curve *B* (fig. 27), showing the results of a back-pressure test made just after the well was treated with acid, and curve *C*, based on the results of a test conducted 5 months later, shows virtually the same relationship between Q and $P_f^2-P_s^2$. During the time between the two tests a total of 105,836,000 cubic feet of gas was produced from the well, and the shut-in pressure declined from 659 to 630 pounds per square inch gage. The absolute open flow of the well was increased from 8,900,000 to 18,600,000 cubic feet of gas per 24 hours or 109 percent (curves *A* and *B*, fig. 27) after being treated with acid, and the absolute open flow of the well at the time of the third test was 17,300,000 cubic feet of gas per 24 hours, or 94 percent greater than that gaged just before the treatment. The decrease in absolute open-flow capacity during the period following treatment of the well with acid from 18,600,000 to 17,300,000 cubic feet per 24 hours was due entirely to decline in reservoir pressure.

The open-flow and shut-in pressure data for 25 of the gas wells in the Monroe field which were treated with acid shown in table 20 include pressures and open flows obtained at the time the wells were completed, just before the wells were treated with acid and just after acid treatment. Subsequent open-flow and shut-in pressure data were obtained for 9 of the wells for studying the permanence

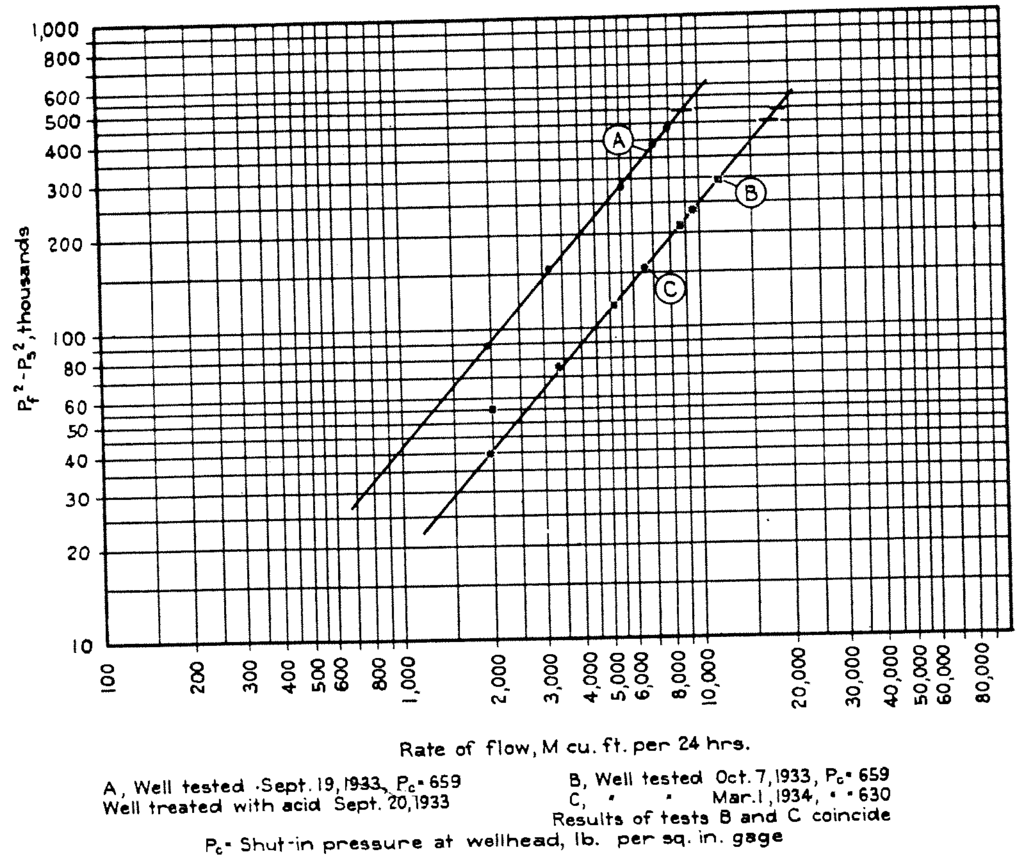


FIGURE 27.—Effect of acid treating on delivery capacities of a gas well

of changes in delivery capacities caused by the acid. Immediate changes in open flows after treating the wells with acid (table 20) range from a loss of approximately 18 percent for well 22 to a gain of approximately 254 percent for well 23, and the total open-flow volume of the 25 wells increased from 125,350,000 to 274,540,000 cubic feet of gas per 24 hours (approximately 119 percent) due to treating the wells with acid. The group of 9 wells which were gaged a third time after having been operated for several months following acid treatment had a total open flow before treatment of 55,470,000 cubic feet of gas per 24 hours compared with 118,600,000 and 104,440,000 cubic feet per 24 hours shortly after acid treatment and several months after acid treatment, respectively. Expressed as percent, these data show an immediate increase in open-flow volume

TABLE 20.—*Results of acid treatment of gas wells in the Monroe field, La.*

Well no.	Open-flow and pressure data at completion of well			Open-flow and pressure data when well was treated with acid				Later open-flow and pressure data			Gas produced between tests after treating wells, M cu. ft.
	Date of completion	Shut-in pressure at wellhead, lb. per sq. in. gage	Open flow, M cu. ft. per 24 hours	Date treated with acid	Shut-in pressure at wellhead, lb. per sq. in. gage	Open flow, M cu. ft. per 24 hours: Before treating	Open flow, M cu. ft. per 24 hours: After treating	Date of test	Shut-in pressure at wellhead, lb. per sq. in. gage	Open flow, M cu. ft. per 24 hours	
1	2/17/18	1,000	14,000	7/15/33	580	7,480	15,970	3/3/34	515	12,740	159,466
2	12/29/29	1,010	31,430	9/16/33	605	5,400	12,640	3/3/34	550	12,940	143,180
3	6/30/33	950	6,000	7/11/33	940	7,650	25,960	3/3/34	815	19,570	534,709
4	6/19/29	1,000	6,350	7/22/33	925	9,400	8,600	3/2/34	885	8,440	53,433
5	12/13/30	985	1,130	7/23/33	840	1,060	1,800	3/2/34	700	1,510	80,234
6	8/15/33	920	3,360	8/21/33	920	3,690	11,610	3/2/34	860	9,940	129,000
7	7/ 5/33	920	1,840	7/14/33	920	1,940	5,620	3/2/34	870	5,870	61,229
8	9/22/28	865	6,310	5/ 1/33	555	3,820	8,110	3/3/34	500	6,840	262,299
9	6/30/33	655	17,740	5/ 3/33	535	15,030	[1]28,290	3/3/34	475	26,590	427,536
10	3/29/29	1,000	7,170	7/17/33	930	6,660	13,140	..	..		..
11	6/21/20	1,050	12,320	6/26/33	665	4,970	11,800	..	..		..
12	8/26/24	1,015	7,340	7/28/33	880	5,620	13,320	..	..		..
13	9/25/30	1,000	2,240	8/28/33	875	1,630	5,390	..	..	..	..
14	3/30/23	900	5,000	9/ 5/33	525	1,440	2,480	..	..	..	..
15	12/23/28	975	10,010	9/ 1/33	900	7,340	21,460	..	..	..	..
16	12/ 9/29	1,030	3,200	8/19/33	980	3,010	7,330	..	..	..	..
17	9/19/25	877	16,690	8/29/33	575	8,600	20,520	..	..	..	..
18	9/19/32	495	2,060	8/ 8/33	460	2,480	6,840	..	..	..	..
19	11/27/26	600	1,010	12/13/33	205	270	890	..	..	..	..
20	10/25/30	975	9,870	11/18/33	920	10,860	23,940	..	..	..	..
21	1/28/23	1,010	2,240	11/25/33	810	2,190	5,620	..	..	..	..
22	4/23/28	975	4,100	8/20/33	925	5,450	4,500	..	..	..	..
23	7/25/30	970	2,470	11/12/33	750	1,120	3,970	..	..	..	..
24	11/24/19	930	16,370	12/ 4/33	475	7,180	11,610	..	..	..	..
25	7/ 6/30	1,020	1,504	11/28/33	780	1,060	3,130	..	..	..	..
						125,350	274,540			104,440	

[1] Obtained from Louisiana Dept. of Conservation records. Remainder of data obtained from operators' records.

of approximately 113 percent after acid treatment and a sustained increase of approximately 87 percent at the termination of an operating period during which the average of the shut-in pressures on the wells decreased from 758 to 686 pounds per square inch (approximately 10 percent). The data also show that if the effect of pressure depletion is considered the increased open-flow capacity was maintained over an operating period of several months duration.

Comparison of the open flows gaged when the wells were completed with the open flows gaged after they were treated with acid shows that in some of the wells the open-flow volumes after acid treatment were greater than those gaged when the wells were new. For example, well 6 (table 20) was treated with acid 6 days after it was completed, and the initial open flow of approximately 3,700,000 cubic feet was increased to approximately 11,600,000 cubic feet of gas per 24 hours. Well 12 (table 20) was treated with acid approximately 9 years after it was completed, during which period the open flow decreased from approximately 7,300,000 to 5,600,000 cubic feet of gas per 24 hours and shut-in wellhead pressure decreased from 1,015 to 880 pounds per square inch gage. The open-flow delivery gaged after acid treatment was approximately 13,300,000 cubic feet of gas per 24 hours.

The treatment of gas wells with acid to increase the rate of availability of gas reserves is very economical compared with the drilling of new wells, since the cost per well for acid treating is less than the cost of material and labor required for connecting most new wells in the gathering system. Due to the relatively low cost of treating gas wells with acid, if an increase in delivery capacity is not maintained satisfactorily or if the increase in delivery capacity is not large enough, a series of acid treatments might prove to be of economic advantage. For example, the open-flow capacity of a well treated initially on May 12, 1933, was increased from 640,000 to 1,200,000 cubic feet of gas per 24 hours. A second charge of acid solution was delivered into the well on July 23, 1933, and the open-flow capacity of 1,060,000 cubic feet gaged before the acid treatment was increased to 1,800,000 cubic feet of gas per 24 hours. Generally, however, if delivery capacities are not increased by treating gas wells with 1 or 2 charges of acid solution additional treating probably would not be successful.

SHOOTING OF GAS WELLS

Shooting consists of exploding a charge of nitroglycerin or other explosive in the well to fracture the gas-bearing stratum and open channels through the reservoir rock to stimulate the flow of gas to the well. Generally, the shooting of a charge of explosives in the well increases its diameter at the producing sand and results in the formation of a cavity in the producing stratum around the well, with fractures extending in various directions. Meals [37] mentions several special reasons for shooting particular kinds of gas wells in the old eastern gas fields where wells are subject to salt-water encroachment. Crystallization of salt on the face of the sand causes considerable trouble in producing the gas, and although fresh water

[37] Meals, S. W., Production of Natural Gas in the Eastern Fields: Natural Gas, September 1931, p. 6.

will dissolve the salt or a small string of "cleaning-out" tools will clean the clogged sand face and remedy the "salting" at least temporarily, the sand sometimes becomes "clogged" so seriously that new drainage lines have to be established in the producing formation by shooting. Meals also describes freezing that occurs in the sand of some wells producing small volumes of gas under conditions of high pressure and mentions that wells in which freezing has occurred have been abandoned because it was assumed that the gas was exhausted. Production of gas from such wells often can be stimulated by shooting if shutting the wells in for a short time to build up the formation pressure or cleaning the sand face with "cleaning-out" tools does not cause gas to flow into the well bore.

Gas wells are shot primarily to stimulate the flow of gas to the well, and the practice of shooting generally is limited to wells where only a small volume of gas is produced and where such factors as clogging and salting of the sand, freezing, or inability to sustain desired flow rates through sands of low permeability can be remedied by the use of explosives. In many wells, the beneficial results of shooting are temporary; that is, the delivery rates corresponding to definite pressure conditions often are greater after wells have been shot, but frequently the wells gradually revert to their original producing conditions. Back-pressure tests on wells before and after shooting can be used to determine the magnitude of the increases in delivery capacity and to gain an idea of the permanence of such increases.

Only a few back-pressure tests were conducted during the study of gaging gas-well deliveries in the attempt to establish definitely the effect of shooting on the delivery capacities of gas wells. The results of back-pressure tests on shot wells in two gas-producing areas are given in figure 28. The results of tests on a well in Osage County, Okla., are shown in example I. The well produced gas from the Bartlesville sand, and at the time of the first back-pressure test on January 4, 1926, the shut-in formation pressure was approximately 194 pounds per square inch absolute and the absolute open flow based on the plotted relationship about 4,500,000 cubic feet of gas per 24 hours. Deliveries of gas from the well under conditions of high back pressure were inconsistent, as shown by the scattered plotted points. The well was "shot" on January 20, 1928, and allowed to produce gas until January 31, 1928, when a second back-pressure test was made. Shooting of the well evidently changed the effective permeability of the sand, and the gas flowed through the sand to the well at a more rapid rate under conditions of high back pressure than before the well was shot. The increased rate of flow of gas to the well was not entirely sustained, as was indicated by the results of the third test on August 12, 1929, when the shut-in formation pressure was approximately 104 pounds per square inch absolute and the absolute open flow approximately 2,500,000 cubic feet of gas per 24 hours. However, if the pressure-flow relationship established by the first test had not changed the absolute open flow would have been less than 1,000,000 cubic feet of gas per 24 hours, corresponding to a shut-in formation pressure of 104 pounds per square inch absolute (based on curve *A*, example I). A fourth test was conducted on May 6, 1930, at which time the formation pressure was 87 pounds per square inch absolute, and it was found that there was only a comparatively small variation between the pressure-flow relationships established by the third and fourth tests.

The results of back-pressure tests on two gas wells producing from the Layton sand [38] in the Oklahoma City field, Oklahoma, are shown in example II (fig. 28). The results of a back-pressure test on a well which was not shot is shown by curve *A*. The absolute open-flow volume based on the plotted pressure-flow relationship

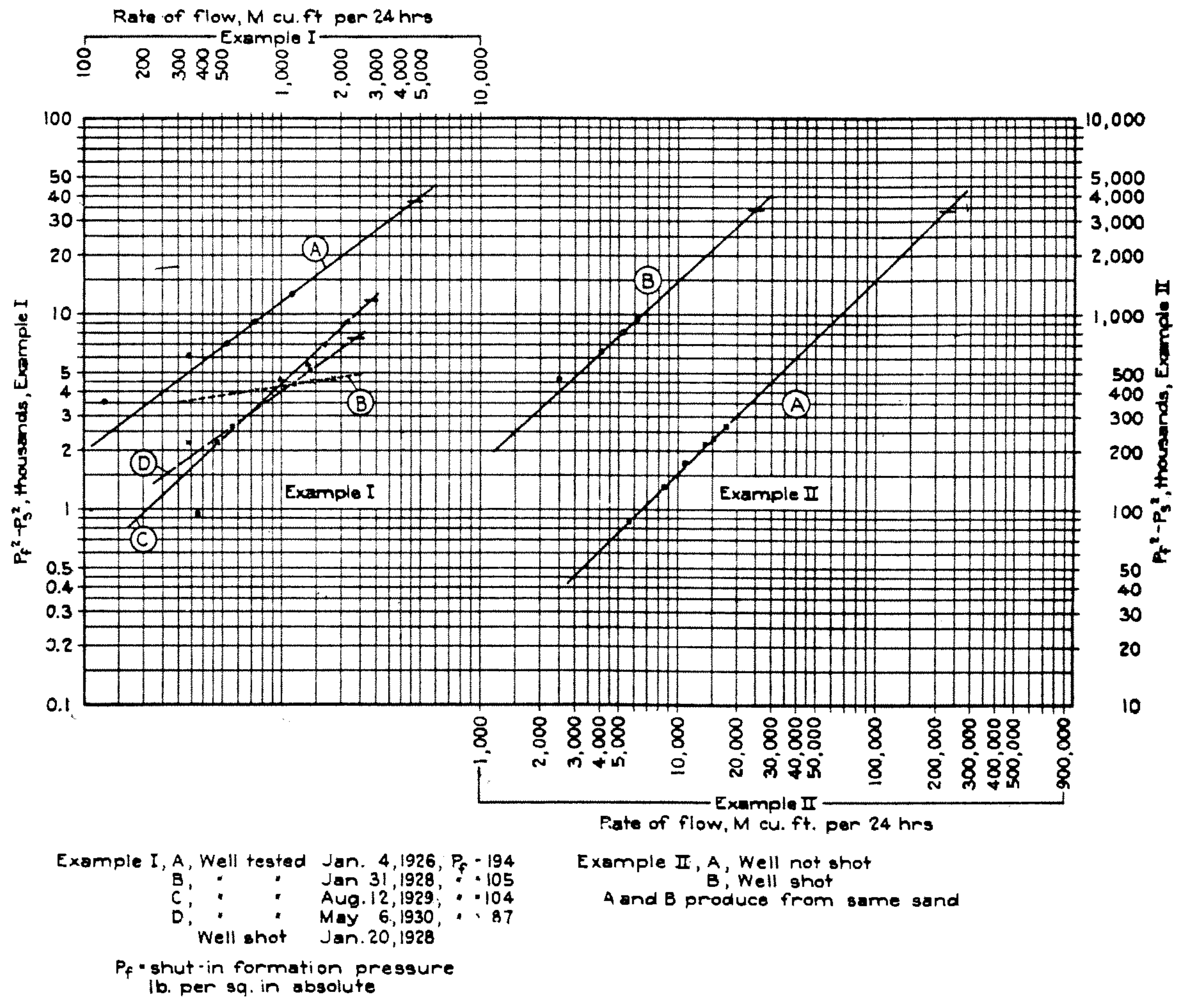


FIGURE 28.—Effect of shooting on delivery capacities of gas wells

was approximately 230,000,000 cubic feet of gas per 24 hours. The results of a back-pressure test on a well that was plugged back from a lower horizon to the Layton sand and the casing opened at this sand by shooting with a charge of 40 quarts of nitroglycerin is shown by curve *B*. The absolute open-flow volume of the well was approximately 22,000,000 cubic feet of gas per 24 hours. Although there is considerable difference in the values of the coefficients obtained from the flow equations of the two Layton-sand wells, which may or may not be due to the different completion methods of

[38] Hill, H. B., and Rawlins, E. L., Estimate of the Gas Reserves of the Oklahoma City Oil Field, Oklahoma County, Oklahoma: Rept. of Investigations 3217, Bureau of Mines, 1933, p. 15.

the two wells, it is interesting to note that the slopes of the two straight lines are virtually the same so the values of n in the flow equations for the two wells are approximately equal.

USE OF PERFORATED LINER OR SCREEN IN GAS WELLS

In completing gas wells where the producing formations are "loose" and there is danger of sand being produced with the gas it is "the usual practice to equip the wells with a perforated liner or screen to prevent the caving of the hole below the seat of the producing string and to hold back sand from loose formations which is dangerous if allowed to reach the inside of the casing." [39] Back-pressure tests were made on several wells equipped with perforated liners and screens. The results of the tests, particularly on wells in the Refugio and Agua Dulce fields in southwest Texas, did not indicate any particular features to distinguish them from the results of tests on gas wells which were not equipped with perforated liners or screens.

The effect of the kind of equipment in a well at or near the producing horizon, the diameter of the well bore, and the depth of penetration into the producing sand can be determined definitely only after special investigations to supplement the results of the experimental work on flow of gas through porous media discussed in appendix 9.

STORAGE OF NATURAL GAS IN DEPLETED FORMATIONS

The feasibility and economic importance of storing natural gas in underground reservoirs to aid in conserving the gas and simplifying producing and distributing operations have been discussed by different authors.[40] Natural gas has been stored in underground reservoirs in California, Kentucky, Kansas, New York, and Texas, and some consideration has been given to such storage in the Burbank field, Oklahoma. One large company operating in the Mid-Continent area stores gas in a depleted gas field near principal markets during the summer months when the demand for gas is a minimum and withdraws stored gas during the winter. The storing

[39] Nowery, B. M., Drilling in the Mid-Continent Area: Natural Gas, June 1931, p. 12.

[40] Beecher, C. E., Repressuring in Early Development: Oil and Gas Jour., Oct. 18, 1928, p. 166.

Bignell, L. G. E., Recharging Old Canadian Gas Field: Oil and Gas Jour., Sept. 25, 1930, p. 41.

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Lake, F. W., Storage and Repressuring in Olinda: Oil and Gas Jour., Oct. 18, 1928, p. 187.

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Meals, S. W., Storing Gas in Natural Reservoirs: Oil and Gas Jour., Apr. 10, 1930, p. 175; The Underground Storage of Gas: Natural Gas, October 1929, p. 8; Storing and Measuring Large Quantities of Gas: Am. Gas. Assoc. Monthly, March 1929, p. 171.

Nickerson, C. M., Repressuring in Depleted Oil Zones: Oil and Gas Jour., Oct. 3, 1929, p. 184.

Pence, R. H., Storage of Waste Gases in the Ground: Oil and Gas Jour., Jan. 23, 1930, p. 138.

Weymouth, T. R., Economic Aspect of Natural-Gas Projects: Am. Gas Assoc. Monthly, December 1929, p. 747.

of surplus gas produced with oil in underground reservoirs until the time when the gas can be utilized has reached a high state of perfection in California and is being considered seriously in many other producing areas. Although this report does not propose to discuss technical and economic features of natural-gas storage it is believed that the principles evolved during the study of gaging gas-well deliveries can be used advantageously to furnish basic data upon which to plan gas-storage projects. For example, the gas-delivery capacities of a well or group of wells in an area that is being considered for a gas-storage project can be determined from back-pressure tests. It then is possible to obtain similar pressure and flow data as gas is being put into the producing formation. Interpretation of such data can be used as a basis for estimating the number of wells that should be operated and the compressor capacities required to make the project an economic success. It was not possible during the study of gaging gas-well deliveries to make a detailed investigation of the applicability of back-pressure data to gas-storage projects, but a few tests were made which indicate that such application will be useful and practical.

STUDY OF NATURAL-GAS FIELDS

The influence of an unstable industrial market for gas and the seasonal variation in domestic consumption seriously affect conservative reservoir drainage. Efficient drainage of reservoir sands and the economic production of gas necessarily are influenced also by the diversity of ownership of many oil- and gas-bearing areas. The maximum rate at which gas can be produced often is considered by many operators as more important than the recovery of the maximum amount of gas from the reservoir sands, but fortunately there is now within the natural-gas industry a trend toward greater economy in development of natural-gas reserves and more efficient recovery of the gas from the reserves than there has been in the past. Consideration is being given to protection of the earning power of the millions of dollars that were invested in the combination of transportation and marketing systems during the recent expansion of the natural-gas industry and to means of insuring fulfilment of the industry's moral obligations to the public. Gas production, transportation, and marketing facilities in reality are closely interrelated, and this fact should be considered when production programs are planned for particular gas reserves.

The extent and nature of a gas reservoir usually cannot be determined until wells have been drilled over a considerable portion of the area overlying the reservoir. The rapidity of development and operation of a gas reserve are, in turn, governed primarily by market demand. Studies of the capacities of reservoirs to deliver gas, the producing characteristics of individual gas wells, and factors that influence deliveries from individual wells during the development of the field and throughout the productive life of gas reserves give information that can be used to develop gas fields economically and to operate wells efficiently.

WELL SPACING

The spacing of gas wells depends primarily upon lease requirements, the maximum seasonal and daily demand for gas, the permeability of the producing formation, the depth of the wells, the cost of drilling wells, and the liquid conditions in the sand. Gas reserves near markets and used mainly during emergencies, such as peak demands or when pipe lines from more distant fields are taken out of service temporarily, may be drilled more intensively (fewer acres per well) than distant reserves which must support the normal demand of a pipe-line system that represents a large monetary investment. The permeabilities of the gas-producing strata of liquid-free reservoirs may have considerable influence on spacing of gas wells to obtain definite delivery capacities from the reservoirs, since both delivery rate and operating pressure may determine the profitable operating life of individual wells. The permeabilities of gas-producing strata and the spacing of gas wells also determine to some extent the abandonment pressure or the percentage of initial reserve of gas which may be recovered. For example, consider that the drilling of 15 wells with an average delivery capacity under open-flow conditions of 20,000,000 cubic feet of gas per 24 hours completed the development of a gas reserve in which the formation pressure was 1,100 pounds per square inch absolute. Consider also that the gas reserve could not be operated profitably if the total delivery from 15 wells, corresponding to an operating pressure at the face of the sand of 50 pounds per square inch absolute, were less than approximately 3,750,000 cubic feet of gas per 24 hours. If factors C and n of the flow equation remain constant throughout the productive life of the wells, the shut-in pressure on the reservoir at the time of abandonment would be 58 pounds per square inch absolute for an n of 0.6 or 134 pounds per square inch absolute for an n of 1.0. If gas were produced from a formation characterized by an n of 1.0 in the pressure-flow relationship until the pressure on the reservoir was 58 instead of 134 pounds per square inch absolute the delivery rate from the group of 15 wells would be decreased from 3,750,000 to 210,000 cubic feet of gas per 24 hours. It would be necessary therefore to drill at least 253 additional wells of the same average production as the original 15 wells to obtain the rate of delivery of 3,750,000 cubic feet of gas per 24 hours.

The increased cost of developing deep gas reserves over that of shallow reservoirs normally is offset partly by the higher gas pressures found in deep reservoirs and by the corresponding larger quantities of gas available from them, and often the recovery cost may not be excessive if the same well spacing is used in developing deep horizons as in developing shallow reserves.

Well spacing also may affect the efficiency of gas recovery from reservoirs which contain "bottom" water or in which "water spread" becomes general as the natural-gas reserve is depleted.

UTILIZATION OF FORMATION PRESSURE IN OPERATION OF GAS WELLS

The conservation and utilization of the formation pressure often are neglected in operating natural-gas wells. Normally, natural-gas pipe-line systems rarely demand an intake pressure greater than

450 pounds per square inch. If the pressure in the delivery lines from the wells is less than that at the intake of the pipe-line system the cost of the initial "boost" in the pressure of the gas at the junction of the gathering system and the main transportation line must be considered. Conservation of gas pressure that may exceed the maximum operating pressure for which the gathering system is designed or will withstand is beyond the control of the operator of the wells, but consideration of the lack of pressure uniformity throughout the area of a single reservoir or of several superimposed or adjacent reservoirs which may supply a common gathering system is important and can be controlled somewhat by the operators. Frequently low-pressure wells should be shut in until the shut-in pressure of all of the wells in the area becomes virtually the same. The character of gas flow from the formation into gas wells also affects pressure conditions in gas-producing areas if open flow instead of commercial delivery capacity is used as the basis for proration of delivery. For example, 30 gas wells having an average absolute open flow of 25,000,000 cubic feet of gas per 24 hours are producing from a reservoir in which there is a uniform pressure of 500 pounds per square inch, and the value of n of the plotted flow characteristic for 20 of the wells is 0.60 and for 10 of the wells 0.90. On that basis the sand-face and wellhead pressure corresponding to delivery rates equivalent to 20 percent of the open-flow capacity of the wells would be as follows:

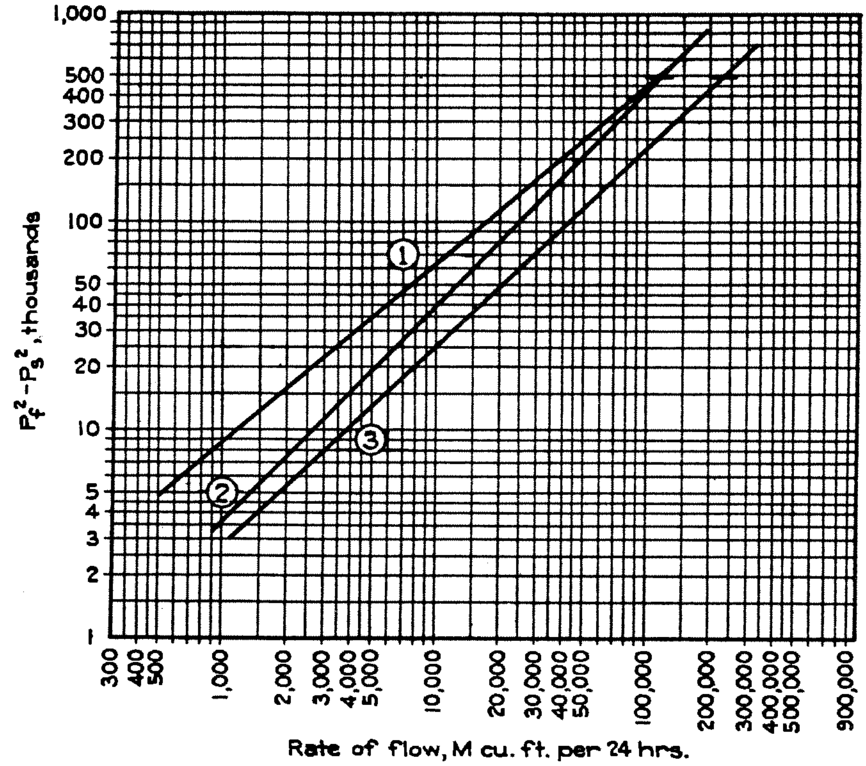
n	Shut-in formation pressure, lb. per sq. in. absolute, P_f	Absolute open flow, M cu. ft. per 24 hours	Depth of well, ft.	Specific gravity of gas (air = 1.00)	Size of flow string, in.	Pressure at sand face,[1] lb. per sq. in. absolute, P_s	Pressure at wellhead,[1] lb. per sq. in. absolute, P_w
0.60	500	25,000	3,000	0.6	6	483	451
.90	500	25,000	3,000	.6	6	457	427

[1] For delivery of 20 percent of absolute open flow = 5,000 M cu. ft. per 24 hours.

If gas is produced from these wells at a rate equivalent to 20 percent of their absolute open-flow capacities the controls on the wells characterized by the n of 0.60 must be regulated so a pressure of 24 pounds per square inch is dissipated at their wellheads.

DELIVERY CAPACITIES OF GAS WELLS IN A SPECIFIC GAS-PRODUCING AREA

An estimate of gas reserves gives information concerning only the volume of gas that can be recovered from the sand and fails to give an idea of the rate of gas availability in the later productive life of a field. Data needed for many engineering problems connected with a study of the gas-delivery capacity of reservoirs are not obtainable from estimates of the amount of gas in reserves. For example, if the average formation pressure in a gas field is 700 pounds per square inch and the amount of gas that can be delivered from the field under peak-load conditions is 50,000,000 cubic feet per 24 hours when the back pressure held on the wells is approximately 95 percent of the formation pressure (665 pounds per square inch) some of the questions which naturally arise with reference to the field are: At what back pressure will the wells have to operate to produce this same peak load after the average formation pressure in the field has declined to 500 pounds per square inch? When will compressors have to be installed and what compressor facilities will be needed? What drilling program should be planned to maintain a desired gas-delivery capacity corresponding to a certain high back pressure? What is the economic relation with regard to the productive life of the field between the number of wells that should be drilled and the installation of pumping facilities in the later life of the field? What factors influence the producing characteristics of individual wells in their later productive life, and how can these



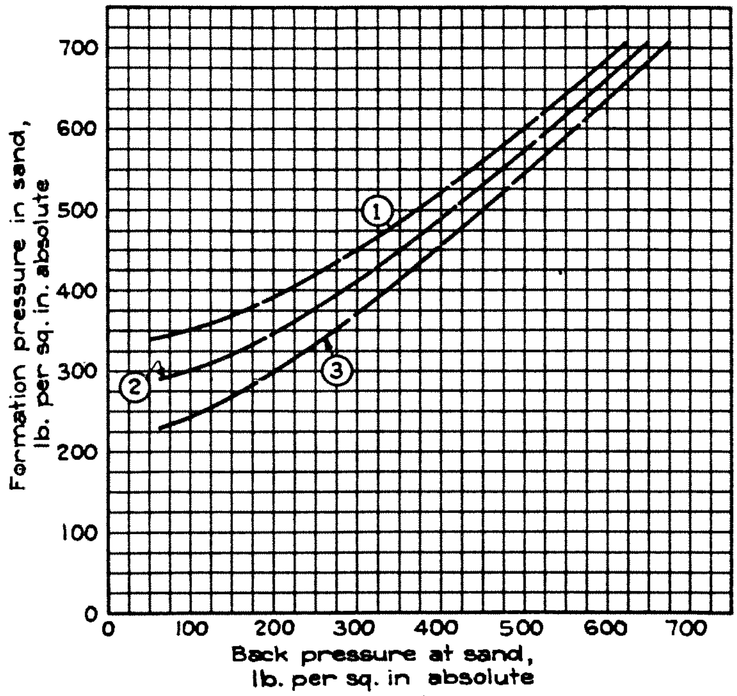
1 and 2, Results of back-pressure tests on individual wells; 3, Combined delivery capacities of 1 and 2

FIGURE 29.—Application of back-pressure data to determine combined delivery capacities of two gas wells in same field

influences be detected and remedied? Axiomatically, if the factors and their influences are known for the individual wells of the field, many of the problems relating to the field as a whole may be solved.

The results of back-pressure tests on gas wells, expressed by a definite relationship between delivery rates and pressure conditions, reveal the delivery capacities of the wells under different pressure conditions. In general, there are changes in the pressure-flow relationship at different times in the productive life of gas wells due to natural causes, but if no changes occur in the well, in the sand, or in the character of the gas produced the relationship between the delivery rates and pressures should be applicable for the productive life of a specific well. In the following discussions the assumption is made that there has been no change in the production-pressure relationships, and it should be understood that interpretations based upon such assumptions must be supplemented with specific and general knowledge of the individual wells and of the field in which they are located.

That wells producing from the same sand in a field can have different flow characteristics is shown by the relationships (curves *1* and *2*, fig. 29) between the delivery rates and the pressure factors, $P_f^2 - P_s^2$, for two wells in which the shut-in formation pressure was virtually the same. The pressure-flow relationship applicable to the combination of the two wells is shown in curve *3* (fig. 29), this relationship having been obtained by adding the gas volumes correspond-



1 and 2, Relationships for individual wells
3, Relationships for combined delivery capacities from 1 and 2

FIGURE 30.—Relationship between formation pressure and back pressure at the face of the sand for delivery of gas at definite rate from gas wells illustrated in figure 29

ing to any particular pressure conditions from curves *1* and *2* and plotting the volumes against the respective pressure conditions.

The relationships shown in figure 29 give some interesting information regarding the delivery capacities of the combination of the two wells. If, for example, a total peak rate of 20,000,000 cubic feet of gas per 24 hours is required from the wells for a period of time the relationships (fig. 29) show that the well represented by curve *1* can produce gas at the peak delivery rate when the difference of the squares of the formation and back pressures is 111,000; the well represented by curve *2* can produce the gas when the difference in the squares of the pressures is 80,000; and the two wells together, when the difference of the squares of the pressures is 49,000. The deduction for the two wells together is made on the

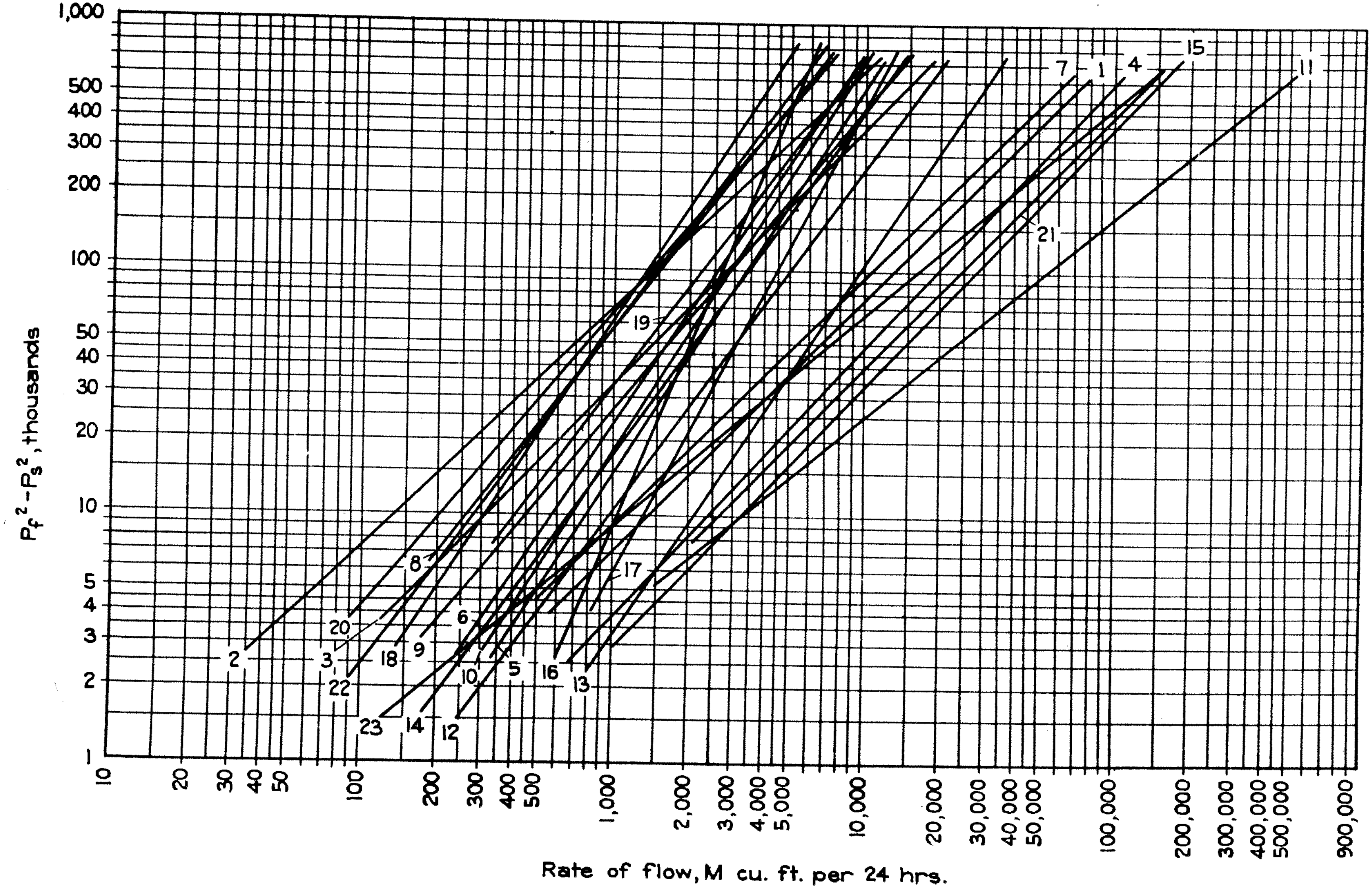


FIGURE 31.—Results of back-pressure tests on 23 gas wells in one field

assumption that the delivery of gas from either well has no effect on the interpretation of back-pressure data relating to the other. The relationship between the back pressure at the sand and the formation pressure for a delivery of 20,000,000 cubic feet of gas per 24 hours is shown in figure 30, where it may be seen that when the formation pressure in the sand has decreased to 400 pounds per square inch the back pressure on the well of curve *1* will have to be decreased to 217 pounds per square inch, on the well of curve *2* to 282 pounds per square inch, and if the two wells are produced together to 333 pounds per square inch.

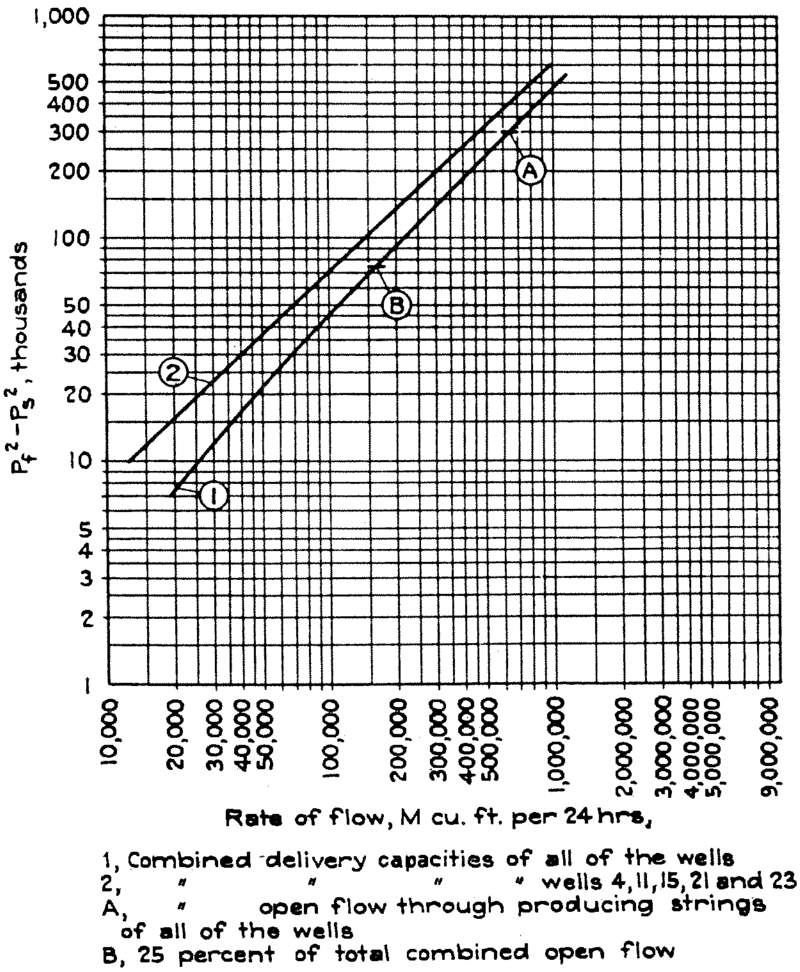
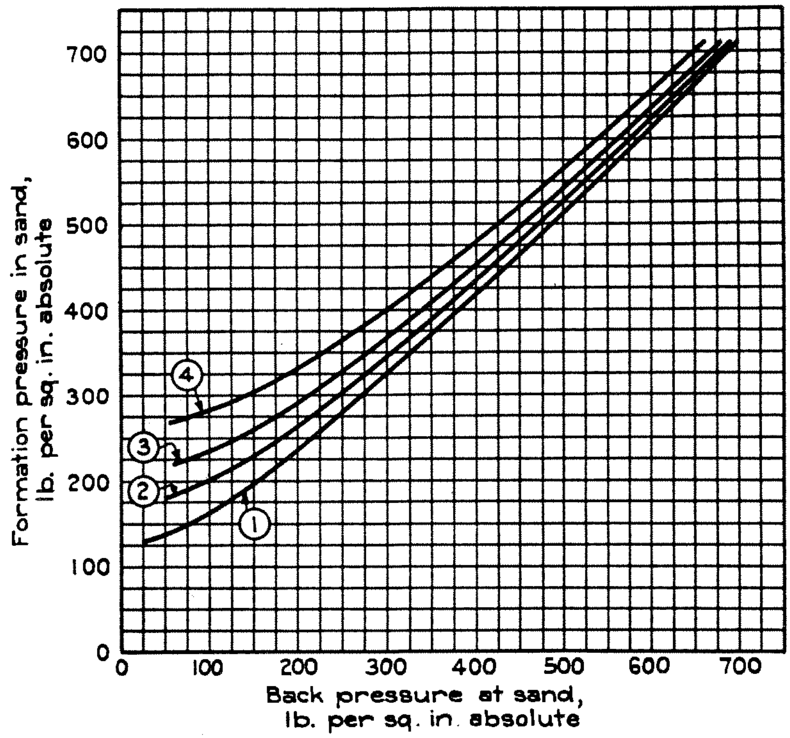


FIGURE 32.—Combined delivery capacities of gas wells illustrated in figure 31

The same sort of reasoning can be applied to an entire field for the general purpose of estimating gas deliveries. The relative back pressures plotted for 23 individual wells in a particular field (fig. 31) show that there is wide variation in delivery rates under the same pressure conditions for different wells, although the shut-in formation pressure in all of the wells was approximately the same. The first glance at figure 31 indicates only a conglomeration of straight lines, but on closer inspection some interesting deductions of delivery capacities of the wells in the field may be made. For example, the relationship between delivery rate and pressures for gas production from all of the wells in the field (based on fig. 31) is shown in curve *1* (fig. 32). As shown, the 23 wells have the capacity to deliver 1,100,000,000 cubic feet of gas per 24 hours when the formation pressure is 710 pounds per square inch, provided that no back pressure is imposed on the face of the sand in the well. Although several wells capable of producing gas at a high delivery rate are included in the 23 wells the back pressure on the formation imposed by the producing strings limits the actual total open flow to 650,000,000 cubic feet of gas per 24 hours, as designated by *A*, curve *1* (fig. 32). Twenty-five percent of the open flow is



1, Combined delivery capacity from all of the wells of 40,000 M cu. ft per 24 hrs.
2, Combined delivery capacity from wells 4, 11, 15, 21, and 23 of 40,000 M cu. ft. per 24 hrs.
3, Combined delivery capacity from all of the wells of 100,000 M cu. ft. per 24 hrs.
4, Combined delivery capacity from wells 4, 11, 15, 21, and 23 of 100,000 M cu. ft per 24 hrs.

FIGURE 33.—Relationships beween formation pressure and back pressure at the face of the sand for definite delivery rates from gas wells illustrated in figure 31

approximately 160,000,000 cubic feet of gas per 24 hours as designated by *B*, curve *1*, and that volume of gas can be produced from the formation when the pressure is 710 pounds per square inch and the back pressure 656 pounds per square inch (92.4 percent of the formation pressure).

The relationship between delivery rate and pressure conditions for five of the large wells selected from figure 31 (wells represented by curves *4*, *11*, *15*, *21*, and *23*) is shown in curve *2* (fig. 32). A comparison of the back pressures required for corresponding formation pressures to produce peak flows of 40,000,000 and 100,000,000 cubic feet of gas per 24 hours from all of the wells in the field and from the five wells is shown in figure 33. Curve *1* illustrates the relationship between the back pressure at the sand and the formation pressure for a delivery of 40,000,000 cubic feet of gas per 24 hours for the entire field; curve *2*, for a delivery of 40,000,000 cubic feet per 24 hours from the five wells; curve *3*, for a delivery of 100,000,000 cubic feet of gas per 24 hours from the entire field; and curve *4*, for a delivery of 100,000,000 cubic feet of gas per 24 hours from the five wells. When the formation pressure has decreased to 400 pounds per square inch a back pressure at the sand of 380 pounds per square inch is required to produce 40,000,000 cubic feet of gas per 24 hours from the entire field, and of 360 pounds per square inch if the gas is produced from the five large wells. If the peak-production demand is 100,000,000 cubic feet of gas per 24 hours when the formation pressure is 400 pounds per square inch the back pressure to be held at the sand is 340 pounds per square inch, and if the gas is produced from the five large wells the back pressure will be 300 pounds per square inch. Similar deductions can be made for any desired conditions of operation of the wells.

A gas field should be operated with the highest back pressure that can be held economically on the sand. The back pressure on the sand is greater than the pressure at the inlet of the gathering line by the pressure due to the weight of the column of gas and the friction drop between the sand and the inlet to the pipe line. The capacity of a section of the pipe line, in turn, is approximately proportional to the inlet pressure, provided the outlet pressure is less than half the inlet pressure. Therefore, operation of gas wells at high back pressure increases the capacities of the pipe lines under peak-load conditions, especially where the lines carry gas to distant markets. There is, however, an economic balance between the amount of drilling that may be done in a gas field to maintain a large reserve availability of gas at high pressure and the installation of pumping facilities to increase the pipe-line capacities while gas is actually being taken from the field at lower pressure.

The fluctuations in the quantities of gas transmitted through pipeline systems are of course related to the quantity of gas being produced from gas fields. When compressors on the pipe lines are increasing the quantity of gas flowing through the pipe lines more gas necessarily is being produced from the gas fields, and if no additional gas wells are used to supply the added demand for gas the average inlet pressure to the transmission system is decreased. For practical purposes the capacities of pipe lines directly connected with the gas fields are approximately proportional to the inlet pressure to the lines, provided the discharge pressure on the pipe lines before they connect with other parts of a gas-transmission system is less than half the inlet pressure. Therefore, if the demand on a transmission system increases suddenly and an attempt is made to take the additional gas required to meet the temporary demand from one field without using any additional gas wells the back pressure on the wells may decrease as much as 20 percent, resulting in a decrease of 20 percent in the capacity of the line from the field which actually should be carrying more gas to meet the peak demand. Three methods then are used to get the required volume of gas to the market: (1) More compressors are operated on the transmission system; (2) more wells are tied into the system to increase the back pressure that is being held on the field and increase the inlet pressure to the pipe line, which in turn requires fewer compressors on the pipe line than in (1); and (3) the pressure of the gas at the inlet end of the pipe line is increased by pumping the gas between the fields and the pipe line. There are times, of course, when either one, a combination of two, or all three methods have to be used.

Since knowledge of the availability of gas from various wells in different gas fields influences the operation of gas-transmission systems a complete record of the pressure and other flow data of the gas wells is essential for efficient operation of gas-transmission systems. If the records are supplemented by results of specially conducted back-pressure tests it is possible to solve many of the problems that arise during the productive life of wells and gas fields and to operate the wells and gas-transmission systems efficiently and economically to meet every demand that may arise.

SUMMARY OF RESULTS OF STUDY OF BACK-PRESSURE DATA ON NATURAL-GAS WELLS AND THEIR APPLICATION TO PRODUCTION PRACTICES

The capacity of a natural-gas well to produce gas usually is determined by measuring the open-flow delivery of the well and the shut-in pressure at the wellhead. The open-flow delivery is measured with a Pitot tube while the well is flowing "wide open," and there necessarily is a loss of a large volume of gas to the atmosphere, especially for those wells where the rate of stabilization of the impact pressure as indicated by the Pitot tube is slow and a long "blowing" period is required to obtain equilibrium conditions. Furthermore, subjecting gas wells to extreme conditions of flow, such as occur when open-flow tests are made, causes sand and lime formations in the well to cave, aggravates water "coning," and increases the possibility of trapping gas permanently by water in the underground reservoir. Also, under such conditions of flow as obtain when wells are gaged by the open-flow method abrasive materials often are carried with the gas from the well at high velocity, damaging well equipment and creating an operating hazard.

Pressure and flow data obtained on gas wells under open-flow conditions only do not indicate the delivery capacity of the wells under normal operating conditions, are not a reliable basis for controlling production, and are not adequate for studying the gas-production problems created by the presence of liquids in the sand, sand caving, shooting, clogging of sand face, and unsuccessful completion jobs.

Analyses of data obtained while the producing characteristics of 582 gas wells in the principal gas-producing areas of the United States were being studied have shown that there is a consistent relationship between the rate of delivery of gas and corresponding pressure differentials between the formation pressure and the pressure at the sand face in the well bore throughout the producing range of a gas well. When rates of delivery of gas are plotted on logarithmic paper against $P_f^2 - P_s^2$—the respective differences of the squares of the formation pressure P_f, and the pressure at the sand face P_s—the relationship is represented by a straight line which may be expressed mathematically by the formula

$$Q = C(P_f^2 - P_s^2)^n,$$

where Q = rate of flow, cubic feet per 24 hours;
C = coefficient;
P_f = shut-in formation pressure, pounds per square inch absolute;
P_s = back pressure at the face of the sand in the well bore, pounds per square inch absolute;
n = exponent, corresponding to the slope of the straight-line relationship between Q and $P_f^2 - P_s^2$ plotted on logarithmic paper.

Rates of delivery of gas corresponding to various back pressures can be ascertained from the plotted relationship established from a limited range of pressure-flow data obtained under relatively high operating pressures and the straight line can be extended to the pressure factor $P_f^2 - P_s^2$ that would exist under open-flow conditions and the open-flow delivery of gas read directly from the plotted relationship.

Obtaining pressure and flow data on gas wells when the back pressures are relatively high for determining the relationship between Q and $P_f^2 - P_s^2$ is called the back-pressure method of gaging gas-well deliveries. In contrast to the open-flow method of gaging gas-well capacities gas wastage is kept at a minimum, accurate measurement of delivery rates usually can be obtained, chances of water encroachment are decreased, and the data not only furnish a method for calculating the open-flow volume of a well but indicate the delivery capacity of the well under normal operating conditions, provide a reliable basis for controlling production, and are more adequate for studying gas-production problems caused by the presence of liquids in the sand, sand caving, shooting, clogging of sand face, and unsuccessful completion jobs.

It is common practice in the gas fields to measure pressure at the wellhead, and under normal conditions shut-in formation pressures and back pressures at the face of the sand can be calculated from the wellhead data, provided the specific gravity of the gas, the depth of the producing stratum, and the diameter of the producing string in the well are known. A bottom-hole pressure gage can be used to measure reservoir pressure in gas wells when it is not possible to calculate correctly the shut-in formation pressure or back pressure at the face of the sand due to liquid conditions in the well.

In gaging the delivery capacity of normal gas wells by the back-pressure method the well to be tested first is shut in at the wellhead, and after the pressure in the well and reservoir sand becomes stabilized the shut-in wellhead pressure is observed. The well then is allowed to produce gas at a high back pressure, and after flow conditions become stabilized again observations are made of the pressure at the wellhead and the rate of delivery of gas from the well. The back pressure then is decreased, and another set of observations of the pressure at the wellhead and the rate of delivery of gas from the well is made. Four sets of observations for back pressures ranging from about 95 or 96 percent to 70 or 75 percent of the shut-in pressure usually furnish enough data to establish the relationship between Q and $P_f^2 - P_s^2$ and determine rates of delivery of gas at lower back pressures, including the absolute open flow of the well (rate of flow of gas that would be obtained if the absolute back pressure at the face of the sand were atmospheric pressure).

Abnormal conditions in some gas wells are reflected by apparent inconsistencies when Q is plotted against $P_f^2 - P_s^2$ on logarithmic paper. Often the relationship cannot be represented by a straight line, and sometimes the plotted points are spaced too irregularly to permit a curve to be drawn through them. The back-pressure data then must be supplemented by extending the range of pressure and gas-delivery rates of the test, by obtaining two or more series of back-pressure data by alternating the sequence of pressure and flow observations in different series of back-pressure data, by observing the behavior of the wellhead pressure following adjustment in the gas-delivery rate and pressure, and by observing the stabilized shut-in pressure on the well before and after back-pressure tests.

The degree of accuracy of the wellhead pressure determination is an important factor in a back-pressure test of a gas well. Error in wellhead pressure is reflected directly in the calculated values of pressure in the reservoir, and a small error in one of the pressures in the factor $P_f^2 - P_s^2$ is reflected as a large-percentage error in the difference of the squares of the two pressures, particularly when the difference between the values of P_f and P_s is small.

Pressure can be measured with dead-weight gages or with spring gages if there is no appreciable lost motion in the mechanism of the gages and negligible variations in observed pressures during consecutive tests when checked against a dead-weight gage tester.

An orifice meter usually is provided in the gathering line from a gas well and can be used to measure the rate of delivery of gas during a back-pressure test if the relation of the pressure on the well to the pressure on the gathering system and of the delivery capacity of the well to the capacity of the gathering system is such that the desired range of back-presure data can be obtained and the gas produced from the well during the back-pressure test can be delivered into the pipe line. The range of pressure-flow data obtainable if the orifice in the orifice meter is not changed and the static pressure on the meter remains approximately constant is limited by the differential pressure range of the meter. If the back pressure on the well is high compared with the pressure on the orifice meter the range of pressure-flow data may be increased by controlling the pressure on the meter. The range of pressure-flow data obtainable also can be increased by changing the size of orifice in the orifice meter.

At some wells it is not practicable to deliver the gas into the pipe-line system while a back-pressure test is being made and it is necessary to vent the gas delivered during the back-pressure test to the atmosphere. However, the gas is delivered at relatively high back pressures, and the rates of delivery are low compared to rates that occur when the well is wide open to the atmosphere (open flow of well). The relatively high back pressures maintained during a back-pressure test eliminate many underground losses of gas and reduce water hazards considerably compared with conditions of open-flow delivery rates. A critical-flow prover generally is better adapted for measuring the delivery of gas vented to the atmosphere from a gas well under relatively high back pressure than a choke nipple or Pitot tube. However, choke nipples can be used advantageously for measuring gas delivery during a back-pressure test on a gas well if the gas stream carries sand or abrasive materials, or for conducting back-pressure tests on wells where the pressure is so high that a critical-flow prover of adequate strength would be heavy and cumbersome. The delivery of gas during a back-pressure test on a low-pressure well can be measured with an orifice well tester or a funnel meter.

Computations of the results of a back-pressure test of a natural-gas involve the following steps:

1. Computing pressures at the sand based on pressure and volume observations made at the wellhead.
2. Determining the value of pressure factor $P_f^2 - P_s^2$ (absolute shut-in formation pressure squared minus back pressure at the sand face squared) and the rate of delivery corresponding to these pressure factors.
3. Plotting on logarithmic coordinate paper values of Q (rate of delivery) against corresponding values of the pressure factor $P_f^2 - P_s^2$.
4. Determining either the absolute open flow or the rate of delivery from the well under any desired pressure condition from the plotted relationship.
5. Comparing the absolute open flow with maximum delivery that could be produced through different sizes of producing strings (for special interpretations).
6. Determining the values of exponent n and coefficient C of the flow equation, $Q = C(P_f^2 - P_s^2)^n$ (for special interpretations).

The absolute formation pressure P_f in a well is determined under static conditions and equals the observed absolute pressure P_c at the wellhead plus the pressure due to the weight of the column of gas in the well. The absolute back pressure P_s at the face of the sand is determined under flow conditions and is equal to the observed absolute pressure P_w at the wellhead plus the pressure drop due to flow through the producing string, plus the pressure due to the weight of the column of gas in the well. If a well is equipped with tubing carrying no perforations above the level of the producing stratum and is packed off at the wellhead so the gas can be produced through the tubing or the annular space between the tubing and casing the pressure may be gaged on the string through which there is no flow, and P_s equals the observed absolute pressure on this string at the wellhead plus the pressure due to the weight of the static column of gas.

Six tables have been prepared by the authors which are readily adaptable for routine computation of the results of back-pressure tests of gas wells (appendix 5).

Back-pressure data generally include the range of pressure and flow conditions under which the well operates, and if correct assumptions are used in computing pressure at the sand from pressure indications at the wellhead results are indicative of the ability of the well to produce gas under its operating pressure and flow conditions. The results of back-pressure tests therefore show whether a more thorough study of a well and more data to analyze the producing characteristics of the well throughout a wide range of pressure and flow conditions are needed. The information gained from back-pressure tests can be applied to the solution of such natural-gas production problems as the effect on delivery capacities of liquid in the well bore and in the producing formation, the rate at which gas should be produced, the variation in gas availability due to the variation in rate of flow stabilization, the effect of treating gas wells with acid, the possible effect of shooting, the accumulation of cavings in the well bore, the changes in producing characteristics of a well during its producing life, and the storage of natural gas in depleted reservoirs. In fact, the application of back-pressure data to the solution of natural-gas production problems and to the interpretation of operating pressure, flow, and reservoir conditions of gas wells is the main field of usefulness of the back-pressure method of gaging gas-well deliveries.

The results of back-pressure tests on gas wells affected by liquid show the advisability of obtaining as many data as possible during a series of back-pressure tests. Obtaining flow and pressure data for different liquid conditions in the well, frequent observations of shut-in pressures, observations of the wellhead pressures during periods of stabilization, changing the sequence of pressure-flow conditions to which wells are subjected during back-pressure tests, and taking more observations than usually are made on back-pressure tests on normal gas wells are necessary for complete study of the behavior of a gas well with liquid in the well bore and the adjacent producing formation, and the data can be used to determine the operating condition of the well where the gas-delivery capacity is least affected by the accumulation of liquid in the well bore or by liquid in the producing formation. For example, the information gained from back-pressure tests shows that tubing and siphon installations are not always the best and most economical remedial measures for solving operating problems due to liquid in gas wells and that liquid conditions often can be controlled and regulated better by producing the gas under proper pressure control.

Many operators use a string of tubing in gas wells to facilitate removal of water. However, wellhead pressures corresponding to the same delivery rates through tubing and casing differ widely because of the greater velocity and pressure drop due to friction for flow through tubing compared with flow through casing. The pressures that can be maintained at the wellhead for different rates of gas delivery into a pipe-line system are important operating considerations and therefore should be considered in designing tubing installations and planning programs for future operation of wells. The results of back-pressure tests can be interpreted to give pressures corresponding to required delivery rates that would be obtained at the wellhead with gas delivery through tubing of different sizes. Comparative back-pressure data obtained before and after the installation of tubing also are exceedingly helpful in studying the producing characteristics of the well and in determining the effect on delivery capacity and operating efficiency of the tubing installation. In general, the results of back-pressure tests on gas wells with liquid in the well show that the bottom-hole data calculated from observations at the wellhead of tubed wells are more reliable than those computed for wells that are not tubed and that tubing facilitates the removal of water, permits more efficient operation and, in some wells, actually leads to an increase in the delivery capacity.

The delivery capacities of gas wells in which beds of shale and lenticular limestone strata are included in the open hole often are affected by the formation of hardened cores in the well bore. Back-pressure data are particularly valuable in studying the problem of accumulation of cavings in the well bore since the effect of cavings on the delivery capacity of a well is much more pronounced, before the cavings become a hardened core, throughout a high back-pressure range of operating conditions than during gas deliveries under open-flow conditions. Often the practical limits of pressure and flow conditions under which wells producing from friable or unbonded formations should be operated can be established by means of back-pressure tests. The results of the interpretation of back-pressure data from wells subject to the accumulation of cavings in the well bore show that in many gas wells cavings affect the delivery capacities of the wells by decreasing the rate of flow of gas throughout the range of pressure conditions to which the well can be subjected and by causing abrupt changes in the delivery capacities under certain conditions of pressure. Also the cavings may be of such a nature that there is no appreciable effect on the delivery capacity of the gas well. Liners often are used to protect gas wells subject to cavings in the well bore, and back-pressure tests can be used as a means for determining the need for and the benefit of the liners.

Back-pressure tests of gas wells characterized by slow stabilization of pressure-flow conditions are affected in two ways: (1) The time required for an accurate back-pressure test often is excessively long, and (2) unless conditions of slow stabilization are recognized calculations based on observations taken under conditions of unstabilized flow may cause erroneous interpretations of gas-delivery capacity. Relationships between delivery rates and pressure factors, $P_f^2-P_s^2$, obtained on wells from such erroneous calculations often are inconsistent with relationships obtained on normal gas wells; and even if the relationships apparently are consistent, results of calculations based on unstabilized flows may indicate an erroneous n of the flow equation, $Q=C(P_f^2-P_s^2)^n$. The conditions of slow stabilization of pressure flow which were experienced during some back-pressure tests also prevail during normal operation of many gas wells in delivering gas into pipe-line systems. Slow stabilization of pressure-flow conditions also has been noticed when open flows of gas wells are gaged with Pitot tubes, and the deliveries of gas calculated from observed impact pressures on Pitot tubes were found to be greater for unstabilized than for stabilized flows.

Where gas wells are subject to very slow rates of stabilization of pressure-flow conditions after adjustment of the delivery rate it is not always possible to wait for absolute stabilization of conditions in the well while a back-pressure test is being conducted. Approximate interpretations of the delivery capacities of such wells can be made, however, from observations after limited periods of flow stabilization if the sequences of delivery rate and pressure observed during the back-pressure tests allow comparisons to be made between the results computed for increasing the rate of flow during a series of readings and those obtained for decreasing the rate of flow during a series of readings. The average relationship between Q and $P_f^2-P_s^2$ is based on the fact that for stabilized pressure-flow conditions computed values of Q corresponding to values of $P_f^2-P_s^2$

will fall on a straight line when plotted on logarithmic paper, regardless of the sequence in which observations are obtained in the test series. An approximate analysis of the delivery capacity of a well under stabilized pressure-flow conditions can be made from data obtained when pressure-flow conditions are not stabilized by (1) determining graphically an average relationship between Q and $P_f^2-P_s^2$ (representing stabilized pressure-flow conditions) from several relationships established when pressure-flow conditions are not stabilized and when the observations are made for different sequences of delivery rates and pressures or (2) observing the behavior of wellhead pressures during stabilization of pressure-flow conditions and determining the stabilized pressures by extending the curves obtained when pressure is plotted against time on coordinate paper.

There are many natural and common factors that tend to change the delivery capacities of gas wells at different times in their productive life which must be considered in interpreting results of back-pressure tests. Back-pressure tests at different times in the productive life of some gas wells have indicated negligible variations in the producing characteristics of the wells; that is, the relationships between flow rates Q and pressure factors $P_f^2-P_s^2$ remained practically the same. When this is true, results of early tests can be used as a basis for determining probable deliveries at later dates, but nevertheless occasional back-pressure tests should be made on all gas wells. Because back-pressure tests conducted at different times in the productive life of some gas wells indicate the same relationships between Q and $P_f^2-P_s^2$ it should not be taken for granted that the relationships will be the same at all times—tests conducted when conditions are different may result in widely varying relationships between Q and $P_f^2-P_s^2$.

The delivery capacities of gas wells indicated by the results of back-pressure tests conducted at different times in the productive life of the wells generally change as the reservoir sands are depleted of gas. Decrease in delivery capacity is caused by liquid or cavings in the well, and there may be other influences on delivery capacity of gas wells that were not apparent from the studies made while the survey upon which this report is based was conducted. However, back-pressure tests frequently suggest remedial measures that should be adopted, and in any event results of back-pressure tests always can be used as a guide for a study and interpretation of conditions in gas wells where the changes during the productive life of the wells are appreciable and seriously affect normal producing operations. Remedial measures tending to increase the operating efficiency of gas wells often involve a "cut-and-try" procedure, at which time the results of back-pressure tests will reveal the effects of the remedial measures.

One operating condition of major importance that affects the delivery capacities of gas wells as interpreted from results of back-pressure tests is the "pull" that has been made on the well just before the back-pressure test; in other words, it must be ascertained whether the well has been delivering gas at an appreciable rate into a pipe-line system, delivering gas at a fairly low rate, or shut in for some time. The operating conditions of wells in the vicinity of the one being studied both at the time of and before the test also affect the delivery capacity. In general, back-pressure tests should be conducted under conditions that will reveal the operating delivery capacities of gas wells.

Although a definite relationship between the delivery rate Q and pressure factor $P_f^2-P_s^2$ which can be made to apply rigidly for interpretation of future operations of gas wells under all operating conditions cannot be established from one back-pressure test thorough understanding of the characteristics of an individual gas well and the conditions under which it is operated often permits interpretation of back-pressure data from which relationships can be established that will be applicable to most efficient operating conditions. Such interpretation of back-pressure data and consideration of the possibilities of factors that can change producing characteristics permit using back-pressure data from one test or from a series of tests to forecast future conditions of operation. Curves expressing graphically the relationship between absolute open flow of a gas well expressed as a percentage of basic absolute open flow and the absolute formation pressure in the sand expressed as a percentage of basic absolute formation pressure are included in this report (fig. 26). The curves apply strictly to conditions of no change in the producing characteristics of a gas well as expressed by the formula $Q=C(P_f^2-P_s^2)^n$, and usually this condition is not found in most gas wells. However, if the curves are used in combination with results of a series of back-pressure tests and with knowledge of the manner in which different factors influence certain gas wells they will be found helpful in solving many gas-production problems, such as forecasting drilling requirements, estimating future production rates, and planning compressor and pipe-line installations. However, in using the data for such studies the back-pressure tests should be conducted under conditions representative of those under which gas wells operate.

The producing formations of gas wells are treated with acid and gas wells are shot to stimulate the flow of gas through the formation to the wells and to increase the delivery capacities of gas wells. Back pressure data can be used advantageously to determine the effect of acid treating and shooting on the delivery capacities of gas wells and on the ultimate recovery of gas from underground reservoirs.

It is believed that the principles evolved during the study of gaging gas-well deliveries can be used advantageously to furnish basic data upon which to plan gas-storage projects. For example, the gas-delivery capacity of a well or group of wells in an area that is being considered for a gas-storage project can be determined from back-pressure tests. It then is possible to obtain basic pressure and flow data when gas is put into the producing formation. Interpretation of such data can be used as a basis for estimating the number of wells that should be operated and the compressor capacity required to make the project an economic success.

Results of back-pressure tests on gas wells not only can be interpreted to give the open-flow delivery and gas-delivery capacity of individual wells but can be applied to a group of wells in a gas field for the formulation of development programs to determine the rate of availability of gas at different operating pressures for pipe-line requirements; also for determining the shut-in formation pressure corresponding to the minimum wellhead pressure and rate of delivery at which a number of wells can be operated economically. The data from back-pressure tests of gas wells also provide a basis for the study of problems involving the efficiency of natural-pressure utilization in the operation of gathering and transportation systems. For example, gas-operating companies usually conduct careful annual surveys of their gas systems to determine the economic balance between the gas-delivery capacities from their gas reserves, the capacities of their gathering and transmission systems to deliver the gas from the gas fields to the markets, and their market requirements; back-pressure data obtained from the gas wells can be made an important source of information in deciding how the gas wells should be operated, how the natural pressure can best be utilized, whether additional gas-compressing facilities are needed, whether additions should be made to gathering and transmission pipe-line facilities, and whether additional gas wells should be drilled.

APPENDIX 1. MEASUREMENT OF DELIVERY RATES WITH ORIFICE METERS DURING BACK-PRESSURE TESTS OF GAS WELLS

The following example illustrates certain factors that must be considered in measuring delivery rates of gas with an orifice meter during back-pressure tests of gas wells when there is a constant

TABLE 21.—*Description of gas wells and measuring facilities illustrating use of orifice meters under constant static pressure conditions during back-pressure tests of gas wells*

Descriptive items	Well I	Well II
Shut-in formation pressure........lb. per sq. in. absolute	1,000	1,000
Absolute open flow........M cu. ft. per 24 hours	30,000	30,000
Depth of well........feet	3,000	3,000
Nominal diameter of flow string........inches	6	6
Specific gravity of gas (air = 1.00)........	0.6	0.6
Value of exponent n[1]........	.55	.90
Diameter of meter run........inches	6	6
Type of connection on meter........	Pipe[2]	Pipe[2]
Size of orifice plate in meter........inches	6 × 2[3] 6 × 3¼	6 × 2[3] 6 × 3¼
Static pressure range of orifice meter........lb. per sq. in.	0 to 500	0 to 500
Differential pressure range of orifice meter........inches of water	0 to 50 0 to 100	0 to 50 0 to 100

[1] From pressure-flow relationship, $Q = (P_f^2 - P_s^2)^n$.
[2] Pressure connections at distance of 2½-pipe diameters upstream and 8 pipe diameters downstream from orifice plate.
[3] Diameter of meter run, 6 inches; diameter of orifice, 2 inches.

pressure on the meters. Assume that back-pressure tests are to be made on two gas wells from which gas is being delivered into gathering systems operating at a constant pressure of 475 pounds per square inch absolute and that delivery rates are to be measured with orifice meters rated to operate at a maximum working pressure not to exceed 500 pounds per square inch absolute. Descriptions of the wells and measuring facilities are shown in table 21.

The range of delivery rates Q and the corresponding back pressure at the sand P_s, for a range of differential pressure from 5 to 45 and from 10 to 90 inches of water, that can be measured with a 2-inch orifice in the 6-inch meter run are described in table 22 and illustrated in figure 34. The delivery rate from well I ($n=0.55$) ranges from 1,367,000 to 4,100,000 cubic feet of gas per 24 hours, corresponding to a differential pressure range on the orifice meter of 5 to 45 inches of water, with a 2-inch orifice in the meter "run." The corresponding pressure at the sand P_s, ranges from 998 to 986 pounds per square inch absolute as illustrated by C, well I (fig. 34). With the same size of orifice in the meter run, the delivery rate from the well ranges from 1,930,000 to 5,780,000 cubic feet of gas per 24 hours, corresponding to a differential-pressure range on the orifice meter of 10 to 90 inches of water, as illustrated by A, well I (fig. 34). The corresponding pressure at the sand P_s, ranges from 996 to 974 pounds per square inch absolute. In comparison, the delivery rate from well II ($n=0.90$) ranges from 1,367,000 to 4,100,000 cubic feet of gas per 24 hours corresponding to a differential-pressure range of 5 to 45 inches of water, while the

TABLE 22.—*Range of back-pressure data for gas deliveries from gas wells against constant pipe-line pressures*[1]

[2-inch orifice in 6-inch line]

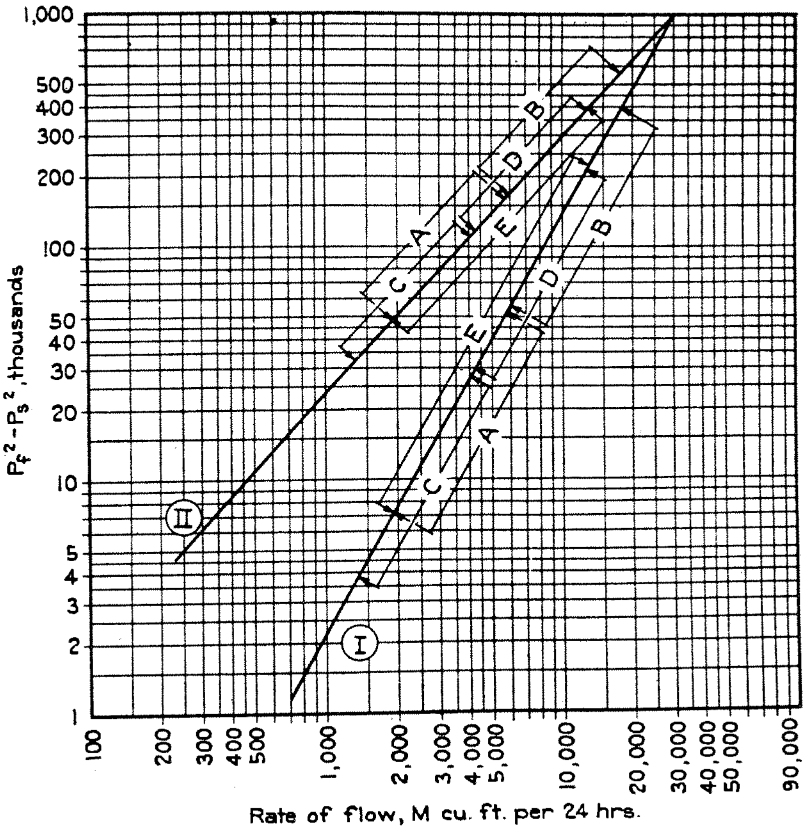
Data	Range of differential pressures on orifice meter			
	0 to 50 inches of water[2]		0 to 100 inches of water[3]	
	Differential pressure of 5 inches of water	Differential pressure of 45 inches of water	Differential pressure of 10 inches of water	Differential pressure of 90 inches of water
Well I, $n = 0.55$				
Rate of flow Q .... M cu. ft. per 24 hours	1,367	4,100	1,930	5,760
Corresponding back pressure at sand P_s .. lb. per sq. in. absolute	998	986	996	974
Well II, $n = 0.90$				
Rate of flow Q .... M cu. ft. per 24 hours	1,367	4,100	1,930	5,780
Corresponding back pressure at sand P_s .. lb. per sq. in. absolute	983	943	975	916

[1] Description of gas wells and measuring facilities is given in table 21.
[2] Designated by C (fig. 34), on respective wells.
[3] Designated by A (fig. 34), on respective wells.

back pressure at the sand P_s, ranges from 983 to 943 pounds per square inch absolute, as illustrated by C, well II (fig. 34). The delivery rate from well II ranges from 1,930,000 to 5,780,000 cubic feet of gas per 24 hours, corresponding to a differential pressure range on the meter of 10 to 90 inches of water, while back pressure at the sand ranges from 975 to 916 pounds per square inch absolute, as illustrated by A, well II (fig. 34). The above illustration emphasizes that the character of flow from gas wells as defined by the relationship between delivery rate Q and pressure factor $P_f^2-P_s^2$ is an important consideration in back-pressure tests of gas wells.

If the 2-inch orifice in the 6-inch meter run is replaced with a 3¼-inch orifice the additional back-pressure data shown in table 23 can be obtained.

The variation in pressure-flow data that can be obtained in back-pressure tests of gas wells where there is a controllable static pressure on the orifice meter is illustrated by the following example: Assume that back-pressure tests are to be made on the same two gas wells described in table 21, except that the gas normally is de-



I - n of $Q = C(P_f^2 - P_s^2)^n = 0.55$ II - n = 0.90

Designation	A	B	C	D	E
Size of orifice, inches	2	3¼	2	3¼	3¼
Static pressure on meter, lb. per sq. in. absolute	475	475	475	475	100 to 500
Differential pressure, inches of water	10 to 90	10 to 90	5 to 45	5 to 45	5 to 45
Meter run of 6-inch pipe					

FIGURE 34.—Range of delivery rates measurable with an orifice meter in back-pressure tests of gas wells

TABLE 23.—*Range of back-pressure data for gas deliveries from gas wells against constant pipe-line pressures*[1]

[3¼-inch orifice in 6-inch line]

Data	Range of differential pressure on orifice meter			
	0 to 50 inches of water[2]		0 to 100 inches of water[3]	
	Differential pressure of 5 inches of water	Differential pressure of 45 inches of water	Differential pressure of 10 inches of water	Differential pressure of 90 inches of water
Well I, n = 0.55				
Rate of flow Q........................M cu. ft. per 24 hours	4,250	12,750	5,990	17,980
Corresponding back pressure at sand P_s..lb. per sq. in. absolute	985	887	973	778
Well II, n = 0.90				
Rate of flow Q........................M cu. ft. per 24 hours	4,250	12,750	5,990	17,980
Corresponding back pressure at sand P_s..lb. per sq. in. absolute	940	781	918	661

[1] Description of gas wells and measuring facilities is given in table 21.
[2] Designated by *D* (fig. 34) on respective wells.
[3] Designated by *B* (fig. 34) on respective wells.

livered into a gathering system against a pressure of 100 pounds per square inch absolute. If the capacity of the pipe-line system can absorb the increased delivery rates the range of pressure and flow data given in table 24 and illustrated in figure 34 can be obtained with a 3¼-inch orifice in the 6-inch line.

As shown in table 24, a delivery rate ranging from 1,944,000 to 13,040,000 cubic feet of gas per 24 hours, corresponding to a differential-pressure range of 5 to 45 inches of water, can be obtained on well I if the 3¼-inch orifice is used under the assumed conditions of flow. The corresponding back pressures at the sand P_s range from 996 to 878 pounds per square inch (see E, well I, fig. 34). Also delivery rates ranging from 1,944,000 to 13,040,000 cubic feet of gas per 24 hours corresponding to a differential-pressure range of 5 to 45 inches of water, can be obtained on well II if the 3¼-inch orifice is used under the assumed conditions of flow, and the corresponding pressures at the sand P_s will range from 975 to 775 pounds per square inch absolute. The advantage of using orifice meters under conditions of controllable static pressure in back-pressure

TABLE 24.—*Range of back-pressure data for gas deliveries from gas wells against controllable pipe-line pressures*[1]

[3¼-inch orifice in 6-inch line]

Well no.	Static pressure on orifice meter, lb. per sq. in. absolute	Differential pressure on orifice meter, inches of water	Rate of flow, M cu. ft. per 24 hours[2]	Back pressure at sand P_s, lb. per sq. in. absolute[2]
I—n = 0.55	100	5	1,944	996
	500	45	13,040	878
II—n = 0.90	100	5	1,944	975
	500	45	13,040	775

[1] Description of gas wells and measuring facilities is given in table 21.
[2] Designated by E (fig. 34) on respective wells.

tests of gas wells is that desired ranges of data can be obtained without frequent changes in the size of orifice plates used for measuring the rates of gas delivery.

Charts similar to that illustrated in figure 34 can be constructed for other types of wells and other conditions of flow, and used to facilitate the planning of back-pressure testing programs.

APPENDIX 2. DESIGN AND USE OF CRITICAL-FLOW PROVERS TO MEASURE DELIVERY RATES OF NATURAL GAS

The essential features of 2-inch and 4-inch internal-diameter provers are shown in detail in figures 35 and 36.

The 2-inch prover (fig. 35) consists essentially of a cylindrical steel bar 12 inches long with a 2-inch-diameter bore. The upstream end of the bar is threaded on the outside with a standard pipe thread and the downstream end with a special thread. A ⅛-inch recess 2⅝ inches in diameter at the downstream end of the bar accommodates an orifice plate. A gasket is placed between the orifice plate and the face of the recess, and the orifice plate is held in the recess by the cap on the head (downstream end) of the prover. A spanner wrench is used to tighten the cap against the face of the prover and thus prevent leakage of gas. The connection for measuring the pres-

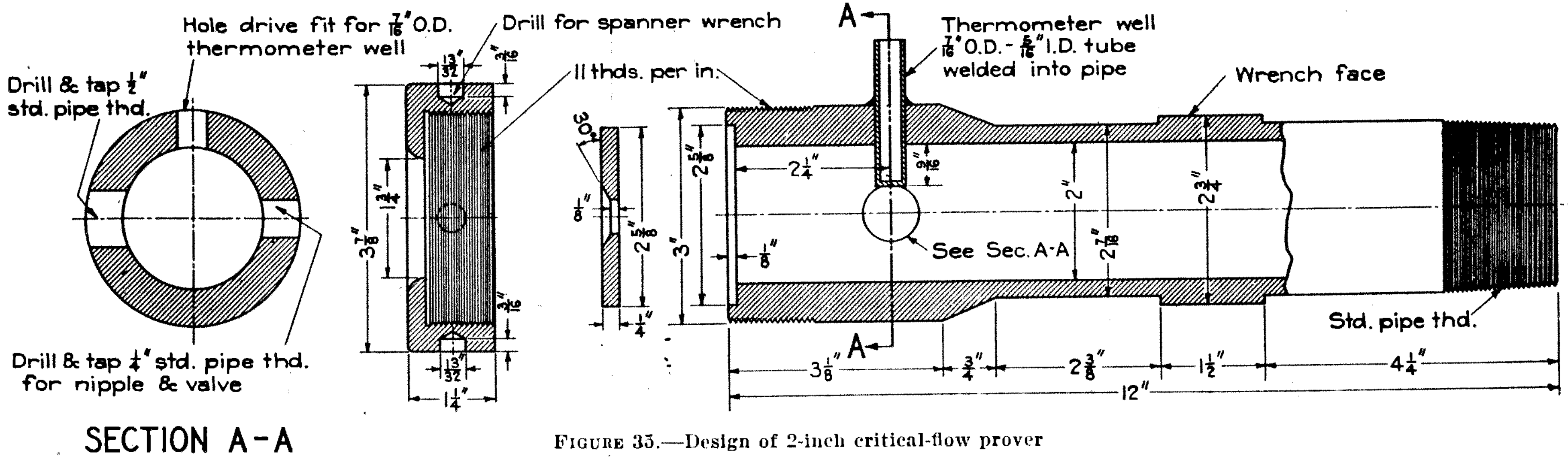


FIGURE 35.—Design of 2-inch critical-flow prover

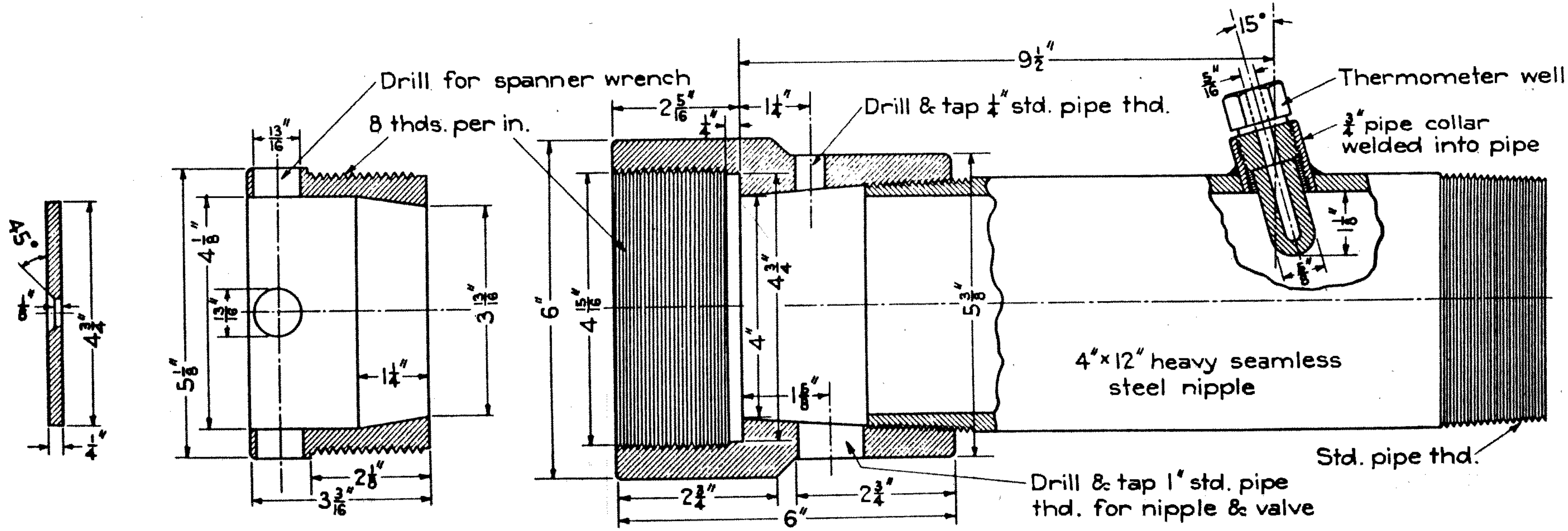


FIGURE 36.—Design of 4-inch critical-flow prover

sure in the prover is made by drilling a hole in its head, tapping the hole for a ¼-inch pipe thread, and using a ¼-inch nipple and gate valve. The temperature of the gas passing through the prover is found by reading a thermometer inserted in a thermometer well welded into the pipe. An additional connection to relieve pressures that might accumulate when orifice plates are changed due to leakage of gas through the valves on wellhead connections is made by drilling and tapping a ½-inch standard pipe-thread hole in the prover into which a ½-inch nipple fitted with a ½-inch valve is screwed. The ½-inch valve is closed when pressure and temperature observations are made. This construction feature (see *B*, fig. 2) is especially helpful when small orifices are used in the prover.

The 4-inch prover illustrated in figure 36 consists essentially of a heavy, seamless steel nipple 12 inches long, with an inside diameter of approximately 4 inches. The upstream end is threaded outside with a standard pipe thread; the other end is tapered and threaded on the outside for a specially constructed steel head, which is recessed and faced so that an orifice plate 4¾ inches in outside diameter can be fitted in the recess. A gasket is placed between the orifice plate and the face of the recess, and the orifice plate is held in position securely by a cap threaded on the outside to fit the threads inside the prover head. Special holes are drilled in the cap so that a spanner wrench can be used to tighten the cap in the prover head. The upstream pressure on the orifice is obtained at the ¼-inch pressure connection, and the up-stream temperature is observed with a mercurial thermometer inserted in the thermometer well which is screwed into a ¾-inch pipe collar welded into the pipe at an angle of 15° from the horizontal. A pressure release—a 1-inch hole drilled and tapped for a 1-inch nipple fitted with a 1-inch valve—is provided to facilitate changing of orifice plates.

Measurement of the rate of delivering natural gas through critical-flow provers is based upon the fundamentals of gas flow through orifices under critical conditions.[41] Delivery rates are governed by the upstream pressure on the orifice and are not affected by the downstream pressure throughout a definite range of pressure conditions. Under the conditions the flow is "critical"; that is, the velocity has reached a maximum and remains constant, and the delivery rate is governed by the density of the gas. Therefore the rate of flow is directly proportional to the absolute upstream pressure and does not change so long as the upstream pressure remains constant, regardless of any change in the downstream pressure.

Theoretically the flow of air through an orifice under conditions of adiabatic and frictionless flow is critical when the ratio between the downstream and upstream pressures is less than 0.528 (where ratio of specific heats is 1.4 and ratio of orifice to pipe diameter approaches zero). However the flow of natural gas through small straight-edge orifices with diameters less than 0.6 pipe diameter is critical for ratios of absolute downstream pressure to absolute upstream pressure less than values varying with conditions from approximately 0.56 to 0.58. Therefore, if the pressure of the gas on the upstream side of an orifice is 500 and on the downstream

[41] Rawlins, E. L. (Bureau of Mines), Flow of Air and Gas Through Small Orifices: Oil and Gas Jour., May 10, 1928, p. 111.

side 200 pounds per square inch absolute the ratio of the downstream to upstream pressure is 0.40. The flow is then critical, and as long as the pressure on the upstream side of the orifice remains 500 pounds per square inch the downstream pressure can range from 15 to 280 pounds per square inch without affecting the upstream pressure or changing the rate of flow of gas. The formula used for computing rates of flow of gas through an orifice under conditions of critical flow is:

$$Q=\frac{CP}{\sqrt{GT}},$$

where Q=rate of flow, M cubic feet per 24 hours at a pressure of 14.4 pounds per square inch and a temperature base of 60° F.;
C=coefficient;
P=upstream pressure, pounds per square inch absolute;
G=specific gravity of the gas (air=1.00);
T=temperature of flowing gas, °F. absolute.

The above formula does not take account of the effect of deviation of the gas from Boyle's law.

CALIBRATION OF ORIFICES FOR 4-INCH CRITICAL-FLOW PROVER

Four sets of orifices to use with the 4-inch prover were made at the Petroleum Experiment Station of the Bureau of Mines, Bartlesville, Okla. The orifices were machined carefully, but no special precautions were taken to make each set conform exactly to the others. Coefficients then were determined by calibrating the orifices to determine the average variation in coefficients for the same size of orifices due to small variations in the diameter and conditions of the upstream edges. The orifices for each set had the following diameters: $\frac{1}{4}$, $\frac{3}{8}$, $\frac{1}{2}$, $\frac{5}{8}$, $\frac{3}{4}$, $\frac{7}{8}$, 1, $1\frac{1}{8}$, $1\frac{1}{4}$, $1\frac{3}{8}$, $1\frac{1}{2}$, $1\frac{3}{4}$, 2, $2\frac{1}{4}$, $2\frac{1}{2}$, $2\frac{3}{4}$, and 3 inches.

The gas used for the calibration tests was taken from a gas well having a shut-in wellhead pressure of approximately 420 pounds per square inch gage and an open-flow volume of approximately 80,000,000 cubic feet of gas per 24 hours. The delivery capacities of the well at high back pressures were large enough to obtain steady conditions of flow, even for the delivery rates required for the calibration of the larger sizes of orifices. The gas was measured through two parallel 6-inch orifice-meter settings with a header at each end of the meter settings. The distance from the upstream header to the orifice meters was approximately 60 feet, equivalent to 120 pipe diameters, and that from the orifice meters to the downstream header approximately 40 feet (80 pipe diameters). The 4-inch prover was connected to the end of a joint of 4-inch pipe leading from the downstream header.

Examples of the data (table 25) obtained during the tests on different sizes of the orifices show a variation of only a fraction of 1 percent in the coefficient of the critical-flow formula for each orifice throughout an appreciable range in absolute upstream pressures on the orifice. The data also give information on the effect of the deviation of natural gas from Boyle's law on calculations of delivery rates through orifices under critical-flow conditions. Practically the same pressures were observed on the orifice meter and on the critical-flow prover for each test, and the deviation of natural gas from

Boyle's law was not considered in the orifice-meter formula or included in the formula written for the flow through the prover orifices under critical-flow conditions. The coefficients of the prover orifices were obtained by equating the orifice-meter formula to critical-flow formula. Therefore, the correction for deviation of natural gas from Boyle's law should be made in the critical-flow formula in the same manner as in the orifice-meter formula [42]; that is the rate of flow before correcting for deviation of natural gas from Boyle's law should be multiplied by the factor $\sqrt{1+\frac{N}{100}}$, where N is the percent deviation [43] of natural gas from Boyle's law.

TABLE 25.—*Examples of data obtained in calibrating orifices under critical-flow conditions*

Size of orifice in prover	Static pressure on orifice meter, lb. per sq. in. abs.	Upstream pressure on critical-flow prover, lb. per sq. in. abs.	Coefficient in critical-flow formula, (calculated)[1]	Maximum variation of coefficient, percent
7/8-inch No. 4	169.07	168.87	305.1	
	117.37	117.17	304.2	0.33
	83.87	83.87	304.1	
3/4-inch No. 3	279.1	278.8	223.5	
	188.6	188.6	223.3	.13
	140.4	140.3	223.6	
5/8-inch No. 4	326.9	326.6	156.8	
	257.6	257.5	156.5	.38
	208.7	208.7	156.2	
1 1/8-inch No. 2	209.0	208.1	499.6	
	156.7	156.2	499.8	.04
	125.1	124.6	499.6	
1 3/8-inch No. 4	192.5	190.5	741.0	
	155.1	153.5	741.6	.08
	127.6	126.3	741.6	
1 1/2-inch No. 4	130.1	128.2	885.9	
	110.6	109.1	885.4	.35
	95.0	93.7	882.8	
1 3/4-inch No. 2	137.1	135.0	1,209	
	119.2	117.4	1,208	.08
	99.7	98.2	1,208	
2-inch No. 3	194.6	189.1	1,596	
	169.8	165.0	1,593	.19
	148.6	144.3	1,596	
5/8-inch No. 1	295.0	295.0	157.0	
	216.9	216.8	156.9	.19
	140.1	140.2	156.7	
1/2-inch No. 4	284.4	284.2	99.74	
	256.0	255.9	99.64	.10
	213.3	213.2	99.69	

[1] Deviation of natural gas from Boyle's law not considered.

Coefficients for all of the orifices made for the 4-inch critical-flow prover are shown in table 26, together with their maximum variation for the four different orifices of each size and the average coefficient for each size of orifice. The variation in the coefficient is comparatively small for orifices having a diameter of ½ inch or more; it is believed that such orifices can be machined carefully to size, and the average coefficients shown in table 26 can be used for routine computations, thereby obviating the necessity of calibrating each particular orifice used in conducting back-pressure tests on

[42] American Gas Association, Natural Gas Department: Gas Measurement Committee Rept. 1, p. 12.

[43] Johnson, T. W., and Berwald, W. B., Deviation of Natural Gas from Boyle's Law: Tech. Paper 539, Bureau of Mines, 1932, pp. 25-26. Johnson and Berwald use symbol n to denote percent deviation from Boyle's law at a given pressure, P. In this report the symbol N is used instead, to avoid confusion with the exponent n of equation $Q = C(P_f^2 - P_s^2)^n$. This use of N to designate percent deviation conforms to the notation in Gas-Measurement Committee Report 1, Natural-Gas Department, American Gas Association.

gas wells. There is some question as to whether coefficients should be established by actual calibration for the ½-inch and smaller sizes of orifices or whether duplicate orifices can be machined and the average coefficients shown in table 26 used for routine computations. For accurate measurements, the best practice doubtless would require the establishment of a coefficient by actual calibration for each orifice with a diameter of less than ½ inch.

CALIBRATION OF ORIFICES FOR 2-INCH CRITICAL-FLOW PROVER

Calibration tests were made on four sets of orifices for the 2-inch prover. The sizes of orifices for which coefficients were established are $\frac{1}{16}$, $\frac{3}{32}$, $\frac{1}{8}$, $\frac{3}{16}$, $\frac{7}{32}$, $\frac{1}{4}$, $\frac{5}{16}$, $\frac{3}{8}$, $\frac{7}{16}$, $\frac{1}{2}$, $\frac{5}{8}$, $\frac{3}{4}$, $\frac{7}{8}$, 1, $1\frac{1}{8}$, $1\frac{1}{4}$, $1\frac{3}{8}$, and $1\frac{1}{2}$ inches. The equipment and experimental procedure used for the calibration tests were similar to those used for the 4-inch prover.

TABLE 26.—*Coefficients*[1] *of orifices for 4-inch critical-flow prover*

Size of orifice, inches	Number of orifice set				Maximum variation, percent	Average coefficient
	1	2	3	4		
¼	24.73	24.74	25.37	24.83	2.59	24.92
⅜	56.00	55.88	56.07	56.07	.34	56.01
½	100.8	100.1	100.3	99.69	1.11	100.2
⅝	156.9	155.9	155.5	156.1	.90	156.1
¾	224.5	223.5	223.5	223.2	.58	223.7
⅞	303.9	304.4	303.8	304.5	.23	304.2
1	396.5	396.3	396.0	396.4	.12	396.3
1⅛	500.2	499.7	498.5	498.5	.34	499.2
1¼	616.0	619.2	615.6	615.0	.68	616.4
1⅜	743.4	741.3	742.4	741.4	.28	742.1
1½	884.7	883.5	884.2	884.7	.14	884.3
1¾	1,209	1,208	1,207	1,208	.17	1,208
2	1,595	1,601	1,595	1,595	.38	1,596
2¼	2,049	2,044	2,047	2,043	.39	2,046
2½	2,569	2,562	2,564	2,569	.27	2,566
2¾	3,177	3,175	3,180	3,177	.16	3,177
3	3,911	3,906	3,903	3,897	.36	3,904

[1] Coefficients obtained from the formula.

$$Q = \frac{CP}{\sqrt{GT}},$$

where Q = rate of flow, M cubic feet per 24 hours, at pressure base of 14.4 pounds per square inch, and temperature base of 60°F.;
C = coefficient for prover orifice;
P = upstream pressure on orifice, pounds per square inch absolute;
G = specific gravity of gas (air = 1.00);
T = absolute flowing temperature, °F.
Deviation of natural gas from Boyle's law not considered.

Coefficients of the orifices calibrated for the 2-inch critical-flow prover are shown in table 27 together with their maximum variation for the four different orifices of each size and the average coefficient for each size of orifice.

ADVANTAGES OF MEASURING DELIVERY RATES OF NATURAL GAS WITH CRITICAL-FLOW PROVERS

Critical-flow provers are particularly well-adapted for measuring delivery rates during back-pressure tests on gas wells, especially where the gas is vented to the atmosphere. Since the downstream pressure is atmospheric and the upstream pressure usually is comparatively high the ratio between the downstream and upstream pressures is very low and critical-flow assumptions are applicable. Furthermore, under conditions of critical-flow measurement difficulties due to turbulence are eliminated. The American Gas Association [44] has pointed out the difficulties of measuring flows of gas with orifice meters when the flow is turbulent and when there are obstructions to the gas flow. When gas is measured with orifice meters measurements are made under conditions of noncritical flow, and the calculations are based on differential pressure (usually in inches of water) across the orifice and the upstream or downstream static pressure. Accordingly, any disturbance in the gas stream that may affect the differential pressure across the orifice also affects the accuracy with which the rate of flow of gas is measured. The same argument applies to noncritical flow of gas through orifices where the flow is vented to the atmosphere. Disturbances in the gas stream, however, do not have an appreciable effect on measurement of gas flows under critical conditions because the measurement depends only upon the upstream pressure on the orifice and is not affected by the differential pressures across the orifice. These facts are important considerations that should be

TABLE 27.—*Coefficients*[1] *of orifices for 2-inch critical-flow prover*

Size of orifice, inches	Number of orifice set				Maximum variation, percent	Average coefficient
	1	2	3	4		
1/16	..	1.498	1.521	1.552	3.61	1.524
3/32	..	3.374	3.336	3.354	1.14	3.355
1/8	..	6.221	6.361	6.322	2.25	6.301
3/16	..	14.17	14.72	14.53	3.88	14.47
7/32	..	19.97	19.60	20.33	3.82	19.97
1/4	..	26.04	25.56	25.99	1.88	25.86
5/16	..	39.48	39.50	40.32	2.13	39.77
3/8	..	56.40	55.90	57.43	2.74	56.58
7/16	..	80.23	80.93	82.10	2.33	81.09
1/2	..	100.6	101.8	102.9	2.29	101.8
5/8	..	153.2	153.2	155.6	1.56	154.0
3/4	225.4	225.5	223.2	225.5	1.03	224.9
7/8	307.4	308.4	307.2	314.2	2.31	309.3
1	405.4	409.0	402.0	410.4	2.09	406.7
1 1/8	516.7	520.1	523.0	523.2	1.26	520.8
1 1/4	653.3	650.9	651.4	674.4	3.61	657.5
1 3/8	799.4	805.9	815.8	810.2	2.05	807.8
1 1/2	979.7	994.1	993.8	1,041.6	6.32	1,002.0

See footnote 1, table 26.

taken into account in testing gas wells by the back-pressure method when measurement of gas deliveries is made at the wellhead, where turbulence in the flow often is created by wellhead fittings. The authors found that at many wells where it was desired to use a 4-inch critical-flow prover for measuring the gas deliveries the only connection on the wellhead to which the back-pressure measuring equipment could be attached was a 2-inch opening, swedged from a 6-inch fitting. Removal of the 6- by 2-inch swedges increased the labor costs and time required for conducting the back-pressure tests. Accordingly, a series of special tests was made to determine what effect, if any, the swedged connections had on measurement of gas deliveries under critical-flow conditions. The experimental set-up employed in calibrating the orifices for the critical-flow provers was used for these tests. Two 4- by 2-inch swedges and a 2-inch nipple were connected in series and installed in the set-up just upstream from the 4-inch prover. Observations then were made for flows

[44] American Gas Association, Natural Gas Department: Gas Measurement Committee Rept. 1, 13 pp.

through several of the orifices under different pressures. Coefficients determined for the orifices with and without the swedged connection in the set-up are given in table 28. The maximum difference between the coefficients with the swedged connection and those without the swedge in the set-up is less than 1 percent, which is within the accuracy of gas-delivery measurements required for back-pressure tests of gas wells.

A critical-flow prover with a series of orifices can be used in either of two ways to obtain data for a back-pressure test on a gas well. A different size of orifice can be used to measure each flow rate in a series of 4 or 5 determinations with the orifice the only means of regulating the wellhead pressure and the gas-delivery rate; or, if desired, the wellhead pressure and the delivery rate can be regulated by one of the valves on the wellhead and the delivery rate

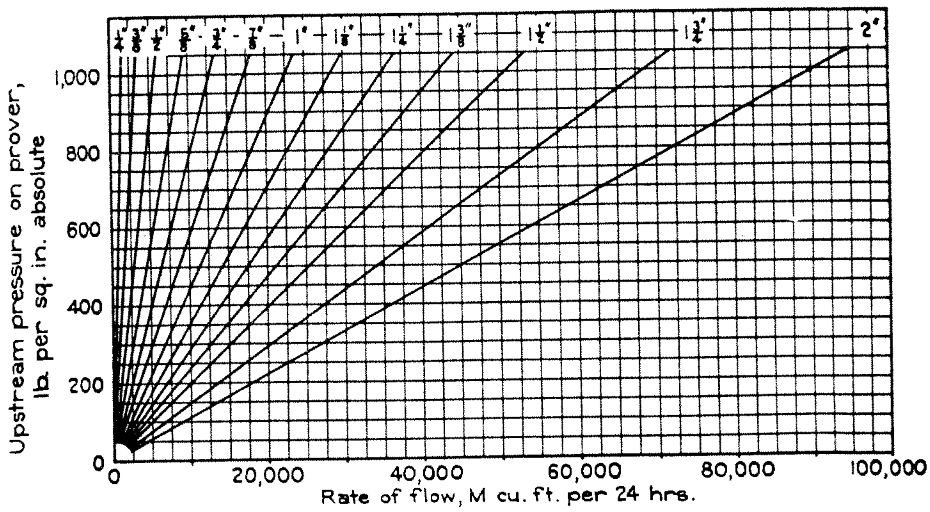
TABLE 28.—*Effect of swedge connection on critical-flow coefficients of orifices for a 4-inch critical-flow prover*

Size of orifice	Differential pressure across swedge, lb. per sq. in.	Critical-flow coefficients		Variation in coefficient, percent
		With swedge connection in set-up	Without swedge connection in set-up[1]	
1½-inch, No. 2	16.7	879.9	883.5	−0.41
	13.6	877.4	883.5	− .69
	12.9	878.1	883.5	− .61
2-inch, No. 2	53.9	1,588.0	1,601	− .81
	47.5	1,589.0	1,601	− .75
	37.9	1,587.0	1,601	− .87
	60.7	1,590.0	1,601	− .69
	42.7	1,587.0	1,601	− .87
	28.1	1,588.0	1,601	− .81
2½-inch, No. 2	143.5	2,567.0	2,550	+ .67
	111.6	2,534.0	2,550	− .63
	76.4	2,549.0	2,550	− .04
1-inch, No. 2	1.1	394.7	396.3	− .40
	1.5	394.9	396.3	− .35
	2.8	397.8	396.3	+ .38
	40.5	395.1	396.3	− .30
	91.1	394.2	396.3	− .53
	119.9	395.0	396.3	− .33

[1] Obtained from table 26.

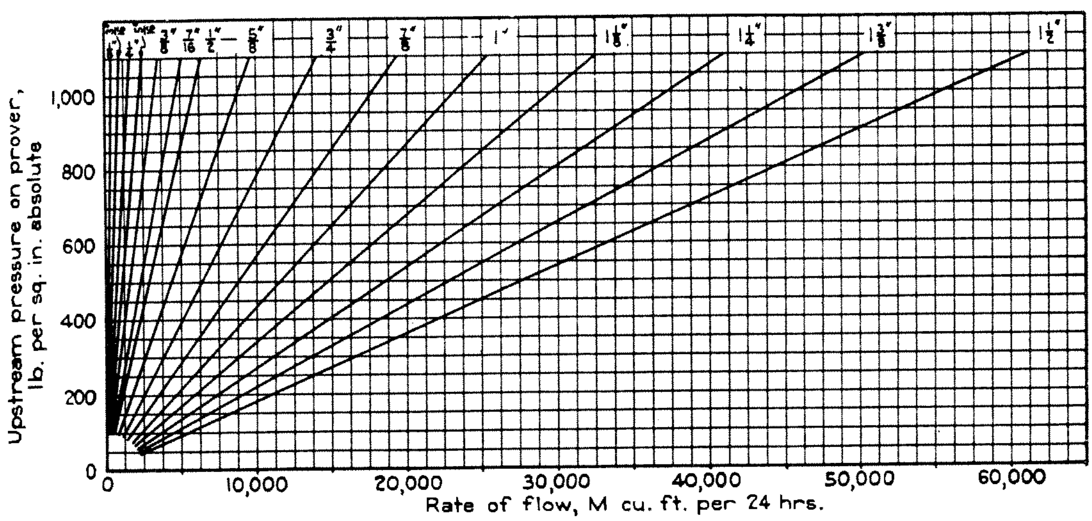
measured with any suitable orifice in the critical-flow prover. This last procedure permits more than one delivery rate to be measured in the series of observations with one size of orifice, but it is believed that best results can be obtained by regulating wellhead pressures and delivery rates with the orifices and using only one size of orifice for each observation. Regulating pressures and flow rates with orifices often eliminates difficulties due to freezing and minimizes wear on the valves, and more reliable data on the temperatures of the flowing gas at the wellhead can be obtained than when regulating by other means.

Figure 37 shows the relationships between pressure and delivery rate for flow of gas through different sizes of orifices in a 4-inch prover, and figure 38 shows the corresponding data for the flow of gas through different sizes of orifices in a 2-inch prover. The charts in figures 37 and 38 will be found helpful in selecting sizes of orifices for regulating and measuring deliveries in back-pressure tests of gas wells.



Gas volumes at pressure of 14.4 lb. per sq. in. absolute, temperature of 60°F., and specific gravity of 0.60 (air = 1.00)

FIGURE 37.—Relationship between pressure and rate of flow for gas delivery through different sizes of orifices in a 4-inch prover



Gas volumes at pressure of 14.4 lb. per sq in absolute, temperature of 60°F., and specific gravity of 0.60 (air = 1.00)

FIGURE 38.—Relationship between pressure and rate of flow for gas delivery through different sizes of orifices in a 2-inch prover

APPENDIX 3. MEASUREMENT OF GAS-DELIVERY RATES WITH CHOKE NIPPLES

Back-pressure tests were made on two types of gas wells where the gas was vented to the atmosphere, and attempts to measure the delivery rate with orifices in a critical-flow prover were unsatisfactory. Abrasive sand particles carried with the gas flow in one type of wells distorted and chipped the soft steel orifices used by the authors [45] and made them unfit for accurate measurement of gas delivery. Back-pressure tests on gas wells of the second type having extremely high formation pressure showed that the critical-flow prover and orifices required to withstand high pressure were so heavy that they were cumbersome to handle. Consequently, choke nipples were used to measure and regulate the delivery of gas during back-pressure tests on these two types of wells. The slight enlargement of the opening of choke nipples during the time required for seven back-pressure tests where the gas flows were accompanied by highly abrasive sand which previously had ruined a number of the soft-steel orifice plates for the critical-flow prover apparently had little effect on the measurement of gas delivery. At certain

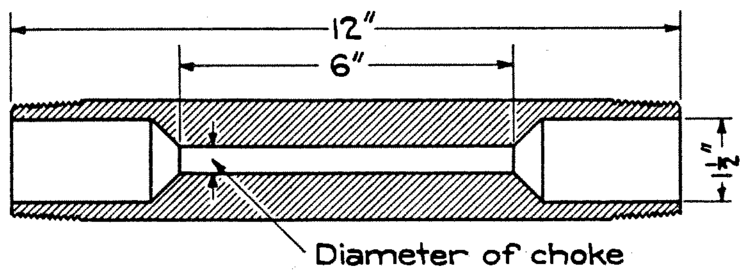


FIGURE 39.—One design of choke nipple for regulation and measurement of deliveries of gas from gas wells

wells, however, even choke nipples would not long withstand the abrasive action of sand moving at high velocity.

The design of one type of choke nipple [46] is shown in figure 39. The nipple is threaded on the outside with a standard pipe thread to permit direct connection to wellhead fittings. The same principles of flow apply to choke nipples and orifices when the flow is critical; that is, under conditions of relatively high pressure on the upstream and atmospheric pressure on the downstream end of the choke nipple the delivery rate depends upon the upstream pressure and the specific gravity and absolute flowing temperature of the gas, or

$$Q=\frac{CP}{\sqrt{GT}},$$

where Q=rate of flow, M cubic feet per 24 hours at a pressure of 14.4 pounds per square inch and a temperature base of 60° F.;
C=coefficient;
P=upstream pressure, pounds per square inch absolute;
G=specific gravity of gas (air=1.00);
T=temperature of flowing gas, °F. absolute

Coefficients [47] for the different sizes of flow passages in a 2-inch outside-diameter choke nipple are shown in table 29. The coefficients

[45] See footnote 15.
[46] Diehl, John C., Natural-Gas Handbook: Metric Metal Works, Erie, Pa., 1927, p. 295.
[47] Based on calculations from Diehl, John C., Natural-Gas Handbook: Metric Metal Works, Erie, Pa., 1927, p. 294.

are higher for choke nipples than for corresponding sizes of straight-edged orifices; that is, the "efficiency" of gas flow through a choke nipple is higher than through a straight-edged orifice of the same diameter.

TABLE 29.—*Coefficients*[1] *for choke nipples when measuring delivery rates under conditions of critical flow*

Size of choke, in.	Coefficient[2]	Size of choke, in.	Coefficient[2]
1/8	6.25	7/16	85.13
3/16	14.44	1/2	112.72
1/4	26.51	5/8	179.74
5/16	43.64	3/4	260.99
3/8	61.21	..	..

[1] Based on data from Diehl, John C., Natural-Gas Handbook: Metric Metal Works, Erie, Pa., 1927, p. 294.

[2] Coefficient C in formula, $Q = \frac{CP}{\sqrt{GT}}$,

where Q = rate of flow, M cu. ft. per 24 hours at pressure base of 14.4 lb. per sq. in. and temperature base of 60 °F
C = coefficient;
P = upstream pressure, lb. per sq. in. absolute;
G = specific gravity of gas (air = 1.00);
T = temperature of flowing gas, °F. absolute.

APPENDIX 4. MEASUREMENT OF GAS-DELIVERY RATES WITH PITOT TUBES

The Pitot tube is used for determining the velocity of fluids in motion. It is simply an instrument that measures the static pressure of the gas stream and at the same time the static pressure plus the dynamic pressure of the flow—the difference between these pressures being the impact pressure of the flow. The impact pressure element is a small bent tube, the short leg of which is inserted in the gas stream at the desired point with the plane of the opening in the tip perpendicular to the direction of the flow of gas. The planes of the openings through which the static pressure is determined parallel the direction of flow. With noncompressible fluids and gases on which the static pressure in the plane of the opening in the Pitot-tube tip is equivalent to that of the atmosphere the approximate velocity of flow is calculated from the specific gravity and temperature of the fluid, the diameter of the gas stream, and the impact pressure, if the velocity distribution in the stream is normal. Any difference between the static pressure and atmospheric pressure has to be considered in calculating the velocity of flow of compressible fluids.

It is common practice throughout the natural-gas industry to use only the impact pressure element of the Pitot tube when the open-flow deliveries from natural-gas wells are measured, and only two observations are made when an open-flow test of a gas well is made—the pressure registered by the impact element of the Pitot tube and the diameter of the pipe or flow nipple through which the gas is discharged.

It was the practice for some time to hold the tip of the impact pressure element in the plane of the opening of the flow nipple at a distance from the inner wall of the nipple equal to one third the diameter of the opening when impact pressure was observed, and the rate of flow then was interpreted from published tables [48] which apparently had been calculated from a formula derived in a manner similar to that first suggested by Robinson.[49] Generally the interpreted values obtained from the published tables were recorded as the open-flow capacities of gas wells without further correction. Although Robinson published a formula for computing gas deliveries measured with Pitot tubes that took into account differences between static and atmospheric pressures the formula was used rarely in calculating the open-flow deliveries from natural-gas wells.

Reid [50] discusses the results of some experimental tests on measuring gas deliveries with Pitot tubes which led him to find some serious errors in the published tables calculated from the adiabatic formula for flow of gas, with the assumption that the static pressure of the gas stream as it leaves the pipe is equal to atmospheric pressure. Obviously such conditions are not applicable because the static pressure is greater than atmospheric when the impact pressure is more than 12 to 14 pounds per square inch. Reid found that when the velocity of the gas flowing from a pipe is equivalent to the velocity of sound in gas—a condition comparable to the critical flow of gases through orifices—there is a definite ratio between the absolute static pressure of the jet and the absolute impact pressure; he also found that the rate of flow is directly proportional to the absolute impact pressure.

Reid published the following formulas, based upon experimental observations, for calculating gas delivery rates measured with a Pitot tube.

Formula 1. Where the impact pressure is less than 15 pounds per square inch gage the formula is:

$$Q=34.69\, d^2\sqrt{W},$$
$$\text{or } Q=128.0\, d^2\sqrt{M},$$
$$\text{or } Q=182.6\, d^2\sqrt{P},$$

where Q = rate of flow, M cubic feet per 24 hours, for a pressure base of 14.7 pounds per square inch, a temperature of 60° F., and a specific gravity of 0.6;

d = internal diameter of discharge pipe, inches;

W = impact pressure, inches of water gage, at center of pipe;

M = impact pressure, inches of mercury gage, at center of pipe;

P = impact pressure, pounds per square inch gage, at center of pipe.

Formula 2. When the impact pressure is greater than 15 pounds per square inch gage the critical-velocity equation is applicable, and the formula is:

$$Q=23.81\, d^2(P+14.7),$$

where Q = rate of flow, M cubic feet per 24 hours, for a pressure base of 14.7 pounds per square inch, a temperature of 60° F., and a specific gravity of 0.6;

P = impact pressure, pounds per square inch gage, at center of pipe.

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[48] Lichty, L. C., Measurement, Compression, and Transmission of Natural Gas: John Wiley & Sons, New York, 1924, pp. 77-78.
Diehl, John C., Natural-Gas Handbook: Metric Metal Works, Erie, Pa., 1927, pp. 291-292.

[49] Robinson, S. W., Measurement of Gas Wells and other Gas Streams: Van Nostrand's Eng. Mag., August 1886, pp. 89-102; Measurement of Gas Wells and Other Gas Streams and the Piping of Natural Gas: Rept. of Geol. Survey of Ohio, vol. 6, 1888, pp. 548-594.
Weymouth, T. R., Measurement of Natural Gas: Trans. Am. Soc. Mech. Eng., vol. 34, 1912, p. 1092.

[50] Reid, Walter, Open-Flow Determination of Gas Wells: Western Gas, November 1929, p. 15.

Reid also found that for critical-flow conditions the absolute static pressure on the pipe 4 diameters from the outlet (side static pressure) is approximately 58 percent of the absolute-center impact pressure and that the rate of flow varies directly with the absolute static pressure. The formula recommended by Reid to calculate rates of flow from observations of side static pressure is as follows:

$$Q = 20.12\, d^2 (M + 30),$$
$$\text{or } Q = 41.05\, d^2 (P + 14.7),$$

where Q=rate of flow, M cubic feet per 24 hours, for a pressure base of 14.7 pounds per square inch, a temperature of 60° F., and a specific gravity of 0.6;
d=internal diameter of pipe, inches;
M=side static pressure, inches of mercury gage;
P=side static pressure, pounds per square inch gage.

Delivery rates corresponding respectively to different impact pressures obtained with a Pitot tube and to side static pressures observed at a distance of 4 pipe diameters upstream from the discharge end of the pipe are given in tables 30, 31, and 32. These tables are derived from the formulas recommended by Reid in which the delivery rates are based on a pressure of 14.7 pounds per square inch, a temperature of 60° F., and a specific gravity of the gas of 0.6 (air=1.00).

It was necessary in the study of gaging gas-well deliveries to compare the open-flow capacities of gas wells as interpreted from back-pressure data with the open-flow capacities measured with Pitot tubes. Accordingly, a study was made to supplement the data described by Reid. The same equipment which was used to calibrate the orifices for the 4-inch critical-flow prover [51] was used for the calibration tests on Pitot tubes, except that the Pitot-tube equipment was substituted for the critical-flow prover.

The Pitot-tube equipment, as shown in figure 40, consists mainly of a 4-inch pipe nipple 42 inches long to which two steel supporting arms *A* are welded. A hole is drilled in each of the supports to hold the Pitot tube securely in position, and a notched semicircular sheet of tin plate, *B*, is fastened to the upper support. Handle *H* is welded to the Pitot tube. The tip of the Pitot tube is in the plane of the opening of the 4-inch nipple, and can be placed at any desired point in the opening by moving handle *H* through a horizontal plane. This equipment was designed particularly to obtain data at distances of $\frac{1}{8}$, $\frac{1}{4}$, $\frac{1}{3}$, $\frac{13}{32}$, and $\frac{1}{2}$ pipe diameters from the inner wall of the 4-inch pipe. Positions on each side of the center position are designated by *X* and *Y* (fig. 40). The position of the tip of the Pitot tube is kept the same under definite flow conditions by locking the pin on the handle *H* in the notches of the semicircular sheet of tin plate *B*. The side-static pressure connection at a distance of 4 pipe diameters from the end of the nipple is designated by *S* in figure 40.

A manifold of two 6-inch orifice-meter settings was used for measurement, and the gas was discharged from the orifice-meter manifold into a 4-inch pipe approximately 20 feet long. The Pitot-tube installation was connected to the discharge of this 4-inch pipe. Impact and side-static pressures on the Pitot-tube installation were observed with dead-weight gages and mercury and water manometers, depending upon the magnitude of these pressures. Static

[51] See appendix 2.

and differential pressures on the orifice meters were observed with dead-weight gages and water manometers, respectively. Preliminary tests were conducted throughout an appreciable range of pressure-flow conditions to establish the relationship between rate of

TABLE 30[1].—*Delivery rates[2] corresponding to different impact pressures[3] measured with a Pitot tube. Impact-pressure values greater than 15 pounds per square inch gage*

Impact pressure, lb. per sq. in. gage	Diameter of opening, inches								
	1	2	3	4	5	6	8	10	12
	Open flow, M cubic feet per day								
15.......	707	2,830	6,360	11,300	17,700	25,500	45,200	70,700	102,000
16.......	731	2,930	6,580	11,700	18,300	26,300	46,800	73,100	105,000
17.......	755	3,020	6,800	12,100	18,900	27,200	48,300	75,500	109,000
18.......	779	3,120	7,010	12,500	19,500	28,000	49,900	77,900	112,000
19.......	802	3,210	7,220	12,800	20,100	28,900	51,300	80,200	115,000
20.......	826	3,310	7,440	13,200	20,700	29,700	52,900	82,600	119,000
21.......	850	3,400	7,650	13,600	21,300	30,600	54,400	85,000	122,000
22.......	874	3,500	7,870	14,000	21,900	31,500	55,900	87,400	126,000
23.......	898	3,590	8,080	14,400	22,500	32,300	57,500	89,800	129,000
24.......	922	3,690	8,300	14,800	23,100	33,200	59,000	92,200	133,000
25.......	946	3,780	8,520	15,100	23,700	34,100	60,500	94,600	136,000
26.......	969	3,880	8,720	15,500	24,200	34,900	62,000	96,900	140,000
27.......	993	3,970	8,940	15,900	24,800	35,700	63,500	99,300	143,000
28.......	1,017	4,070	9,150	16,300	25,400	36,600	65,100	102,000	146,000
29.......	1,040	4,160	9,360	16,600	26,200	37,400	66,600	104,000	150,000
30.......	1,064	4,260	9,580	17,000	26,600	38,300	68,100	106,000	153,000
32.......	1,112	4,450	10,000	17,800	27,800	40,100	71,200	111,000	160,000
34.......	1,159	4,640	10,400	18,600	29,000	41,700	74,200	116,000	167,000
36.......	1,207	4,830	10,900	19,300	30,200	43,500	77,300	121,000	174,000
38.......	1,255	5,020	11,300	20,100	31,400	45,200	80,300	126,000	181,000
40.......	1,302	5,210	11,700	20,800	32,600	46,900	83,400	130,000	188,000
45.......	1,421	5,690	12,800	22,800	35,500	51,200	91,000	142,000	205,000
50.......	1,540	6,160	13,900	24,700	38,500	55,400	98,600	154,000	222,000
55.......	1,660	6,640	15,000	26,600	41,500	59,800	106,000	166,000	239,000
60.......	1,778	7,120	16,000	28,500	44,500	64,000	114,000	178,000	256,000
65.......	1,898	7,600	17,100	30,400	47,500	68,400	122,000	190,000	273,000
70.......	2,017	8,060	18,200	32,300	50,400	72,600	129,000	202,000	290,000
75.......	2,136	8,840	19,200	34,200	53,400	76,800	137,000	214,000	308,000
80.......	2,252	9,010	20,300	36,000	56,400	81,100	144,000	225,000	324,000
90.......	2,492	9,980	22,400	39,900	62,400	89,800	160,000	249,000	359,000
100.......	2,732	10,900	24,600	43,700	68,400	98,400	175,000	273,000	394,000
110.......	2,970	11,900	26,700	47,500	74,200	107,000	190,000	297,000	428,000
120.......	3,208	12,800	28,900	51,300	80,200	116,000	205,000	321,000	462,000
130.......	3,445	13,800	31,000	55,100	86,200	124,000	221,000	345,000	496,000
140.......	3,681	14,700	33,100	58,900	92,000	133,000	236,000	368,000	530,000
150.......	3,921	15,700	35,300	62,800	98,000	141,000	251,000	392,000	565,000
160.......	4,160	16,700	37,500	66,600	104,000	150,000	266,000	416,000	599,000
170.......	4,399	17,600	39,600	70,400	110,000	158,000	282,000	440,000	634,000
180.......	4,635	18,600	41,700	74,200	116,000	167,000	297,000	464,000	668,000
190.......	4,870	19,500	43,900	78,000	122,000	175,000	312,000	487,000	702,000
200.......	5,108	20,500	46,000	81,800	128,000	185,000	327,000	511,000	736,000

[1] Based on Reid's formula. See Reid, Walter, Open-Flow Determination of Gas Wells: Western Gas, November, 1929, p. 15.
[2] Rates of flow in this table expressed in M cu. ft. per 24 hours, based on a pressure of 14.7 lb. per sq. in., a temperature of 60°F., and a specific gravity of 0.6.
[3] Impact pressure at center of pipe.

flow and impact pressure when the tip of the Pitot tube was at the center of the discharge opening of the pipe. Tests then were conducted to establish a similar relationship when the tip of the Pitot tube was on either side of the center position at a distance from the inside wall equivalent to one third of the internal diameter of the pipe. Tests also were conducted at three different rates of flow

TABLE 31[1].—*Delivery rates*[2] *corresponding to different impact pressures*[3] *measured with a Pitot tube. Impact-pressure values less than 15 pounds per square inch gage*

Impact pressure			Diameter of opening, inches								
Water, inches	Mercury, inches	Pounds per square inch	1	2	3	4	5	6	8	10	12
			Open flow, M cubic feet per day								
0.1	..	..	10.97	44	99	176	274	395	702	1,100	1,580
.2	..	..	15.52	62	140	248	388	559	994	1,550	2,240
.3	..	..	19.00	76	171	304	475	684	1,220	1,900	2,740
.4	..	..	21.95	88	198	351	549	790	1,410	2,200	3,160
.5	..	..	24.53	98	221	392	613	882	1,570	2,450	3,530
.6	..	..	26.89	108	242	430	672	968	1,720	2,690	3,870
.7	..	..	29.03	116	261	464	726	1,050	1,860	2,900	4,180
.8	..	..	31.02	124	279	497	776	1,120	1,990	3,100	4,470
.9	..	..	32.92	132	296	526	823	1,180	2,110	3,290	4,740
1.0	..	..	34.69	139	312	555	867	1,250	2,220	3,470	5,000
1.25	..	..	38.78	155	349	620	969	1,400	2,480	3,880	5,580
1.36	0.10	..	40.45	162	364	648	1,010	1,460	2,590	4,050	5,820
1.6	.12	..	43.89	175	395	702	1,100	1,580	2,810	4,390	6,320
1.8	.13	..	46.56	186	419	744	1,160	1,680	2,980	4,660	6,700
2.0	.15	..	49.00	196	441	784	1,230	1,760	3,140	4,900	7,060
2.2	.16	..	51.45	206	463	823	1,290	1,850	3,290	5,150	7,410
2.4	.18	..	53.74	214	483	860	1,340	1,930	3,440	5,370	7,740
2.7	.20	..	57.20	228	515	915	1,430	2,060	3,660	5,720	8,230
3.0	.22	..	60.02	240	540	961	1,500	2,160	3,840	6,000	8,640
3.5	.26	..	64.91	260	584	1,040	1,620	2,340	4,160	6,490	9,340
4.1	.30	..	70.01	280	630	1,120	1,750	2,520	4,480	7,000	10,100
4.5	.33	..	73.60	295	662	1,180	1,840	2,650	4,710	7,360	10,600
5.0	.37	..	77.57	310	698	1,240	1,940	2,790	4,960	7,760	11,200
5.4	.40	..	80.90	324	728	1,300	2,020	2,910	5,180	8,090	11,700
6.0	.44	..	84.91	340	764	1,360	2,120	3,060	5,430	8,490	12,200
6.8	.50	..	90.48	362	814	1,450	2,260	3,260	5,790	9,050	13,000
8.2	.60	..	99.20	396	892	1,590	2,480	3,570	6,350	9,920	14,300
9.0	.66	..	104.0	416	936	1,670	2,600	3,750	6,660	10,400	15,000
9.5	.70	..	107.0	428	962	1,710	2,680	3,850	6,850	10,700	15,400
10.0	.74	..	109.7	439	987	1,760	2,740	3,950	7,020	11,000	15,800
10.9	.80	..	114.5	458	1,030	1,830	2,860	4,120	7,330	11,500	16,500
12.0	.88	..	120.1	481	1,080	1,920	3,000	4,330	7,690	12,000	17,300
12.2	.90	..	121.4	486	1,090	1,940	3,040	4,370	7,770	12,100	17,500
13.9	1.02	0.5	129.2	517	1,160	2,070	3,230	4,650	8,270	12,900	18,600
15.0	1.1	..	134.2	537	1,210	2,150	3,360	4,830	8,590	13,400	19,300
16.3	1.2	..	140.1	560	1,260	2,240	3,500	5,040	8,960	14,000	20,200
17.7	1.3	..	145.8	584	1,310	2,330	3,650	5,250	9,330	14,600	21,000
19.0	1.4	..	151.4	606	1,360	2,420	3,790	5,450	9,680	15,100	21,900
20.4	1.5	..	156.7	627	1,410	2,510	3,920	5,640	10,000	15,700	22,600
21.8	1.6	..	161.8	648	1,460	2,590	4,050	5,820	10,400	16,200	23,300
24.5	1.8	..	171.7	686	1,550	2,750	4,290	6,180	11,100	17,200	24,700
27.2	2.0	1.0	180.9	734	1,630	2,890	4,520	6,510	11,600	18,100	26,000
29.9	2.2	..	189.7	768	1,710	3,040	4,740	6,830	12,100	19,000	27,300
32.6	2.4	..	198.0	802	1,780	3,170	4,950	7,130	12,700	19,800	28,500
..	2.6	..	206.1	824	1,860	3,300	5,150	7,420	13,200	20,600	29,700
..	2.8	..	214.0	857	1,930	3,420	5,350	7,700	13,700	21,400	30,800
..	3.0	1.5	221.6	887	2,000	3,550	5,540	7,980	14,200	22,200	31,900
..	3.2	..	228.9	917	2,060	3,660	5,720	8,240	14,600	22,900	32,900
..	3.4	..	235.8	943	2,120	3,770	5,900	8,480	15,100	23,600	34,000
..	3.6	..	242.8	971	2,180	3,880	6,070	8,740	15,500	24,300	35,000
..	3.8	..	249.4	998	2,240	3,990	6,230	8,980	16,000	24,900	35,900
..	4.0	2.0	255.9	1,020	2,300	4,090	6,400	9,210	16,400	25,600	36,800
..	4.2	..	262.0	1,050	2,360	4,190	6,550	9,430	16,800	26,200	37,700
..	4.4	..	268.4	1,070	2,410	4,290	6,710	9,650	17,200	26,800	38,600
..	4.6	..	274.5	1,100	2,470	4,390	6,860	9,880	17,600	27,500	39,500
..	4.8	..	280.3	1,120	2,520	4,490	7,010	10,100	18,000	28,000	40,400
..	5.0	2.5	286.1	1,140	2,570	4,580	7,150	10,300	18,300	28,600	41,200
..	5.2	..	291.8	1,170	2,630	4,670	7,300	10,500	18,700	29,200	42,000
..	5.4	..	297.4	1,190	2,680	4,760	7,440	10,700	19,000	29,700	42,800
..	5.6	..	302.7	1,210	2,720	4,840	7,560	10,900	19,400	30,300	43,600

TABLE 31[1].—*Delivery rates*[2] *corresponding to different impact pressures*[3] *measured with a Pitot tube. Impact-pressure values less than 15 pounds per square inch gage*—Continued

Impact pressure			Diameter of opening, inches								
Water, inches	Mercury, inches	Pounds per square inch	1	2	3	4	5	6	8	10	12
			Open flow, M cubic feet per day								
..	5.8	..	308.1	1,230	2,770	4,920	7,700	11,100	19,700	30,800	44,300
..	6.0	3.0	313.4	1,250	2,820	5,010	7,830	11,300	20,000	31,300	45,100
..	6.5	..	326.0	1,300	2,930	5,220	8,150	11,700	20,900	32,600	47,000
..	7.0	3.5	338.6	1,350	3,050	5,420	8,460	12,200	21,700	33,900	48,800
..	7.5	..	350.0	1,400	3,150	5,600	8,760	12,600	22,400	35,000	50,400
..	8.0	4.0	361.5	1,450	3,250	5,780	9,040	13,000	23,100	36,200	52,100
..	8.5	..	372.9	1,500	3,370	5,980	9,340	13,400	23,900	37,400	53,700
..	9.0	4.5	383.9	1,540	3,460	6,140	9,600	13,800	24,600	38,400	55,300
..	9.5	..	394.2	1,580	3,550	6,310	9,860	14,200	25,200	39,400	56,800
..	10.0	..	404.6	1,620	3,640	6,470	10,100	14,600	25,900	40,500	58,200
..	10.2	5.0	408.1	1,630	3,680	6,540	10,200	14,700	26,100	40,800	58,800
..	11.2	5.5	428.0	1,710	3,850	6,850	10,700	15,400	27,400	42,800	61,600
..	12.2	6.0	447.0	1,790	4,030	7,150	11,200	16,100	28,600	44,700	64,400
..	13.2	6.5	465.5	1,860	4,190	7,450	11,600	16,800	29,800	46,600	67,000
..	14.3	7.0	483.0	1,930	4,350	7,730	12,100	17,400	30,900	48,300	69,600
..	15.3	7.5	500.0	2,000	4,500	8,000	12,500	18,000	32,000	50,000	72,000
..	16.3	8.0	516.0	2,060	4,650	8,260	12,900	18,600	33,000	51,600	74,300
..	17.3	8.5	532.1	2,130	4,790	8,520	13,300	19,200	34,100	53,200	76,600
..	18.3	9.0	548.0	2,190	4,930	8,770	13,700	19,700	35,100	54,800	78,900
..	19.3	9.5	563.0	2,250	5,070	9,000	14,100	20,300	36,000	56,300	81,100
..	20.4	10.0	577.6	2,310	5,200	9,240	14,400	20,800	37,000	57,800	83,200
..	22.4	11	605.6	2,420	5,450	9,680	15,100	21,800	38,800	60,600	87,200
..	24.4	12	632.5	2,530	5,700	10,100	15,800	22,800	40,500	63,300	91,200
..	26.5	13	658.0	2,630	5,920	10,500	16,500	23,700	42,100	65,800	94,800
..	28.5	14	683.8	2,740	6,150	10,900	17,100	24,600	43,800	68,400	98,600

[1], [2] and [3]. See footnotes 1, 2, and 3, table 30.

to determine the variation in impact pressure across the face of the opening of the discharge pipe. These pressure traverses were established from observations made at distances from the inside wall equivalent to $\frac{1}{8}$, $\frac{1}{4}$, $\frac{1}{3}$, $\frac{13}{32}$, and $\frac{1}{2}$ of the inside diameter of the pipe.

The relationship between rate of flow and impact pressure under conditions of critical flow when the tip of the Pitot tube was at the center of the discharge opening of the pipe is shown by *A* (fig. 41). The rate of flow is expressed in cubic feet of gas per 24 hours using pressure and temperature bases of 14.7 pounds per square inch and 60° F., respectively, and a specific gravity of 0.7 (air=1.00). The rate of flow was approximately proportional to the absolute impact pressure for the higher impact pressures. The results obtained by Reid for flow through a 4-inch discharge opening are shown by *B* (fig. 41). The relationship between rate of flow and impact pressure under conditions of critical flow when impact pressures were observed at distances from the wall equivalent to one third the internal diameter of the pipe is shown by *A* and *B* (fig. 42). Curves *A* and *B* represent the relationships obtained on the two sides of the center position in the discharge opening of the pipe, designated by *X* and *Y* (fig. 40), and the rate of flow was found to be proportional to the absolute impact pressure for the higher values of impact pressures. Rates of flow corresponding to different impact pressures as obtained from commonly used Pitot-tube tables are shown by *C* (fig. 42), and as indicated there is an appreciable difference, especially at high impact pressures, between results shown by curve *C* and those illustrated by curves *A* and *B*.

The relationship between rate of flow and impact pressure where the flow was not critical and when the tip of the Pitot tube was at the center of the discharge opening of the pipe is shown by figure 43. The relationship when the impact pressure was observed

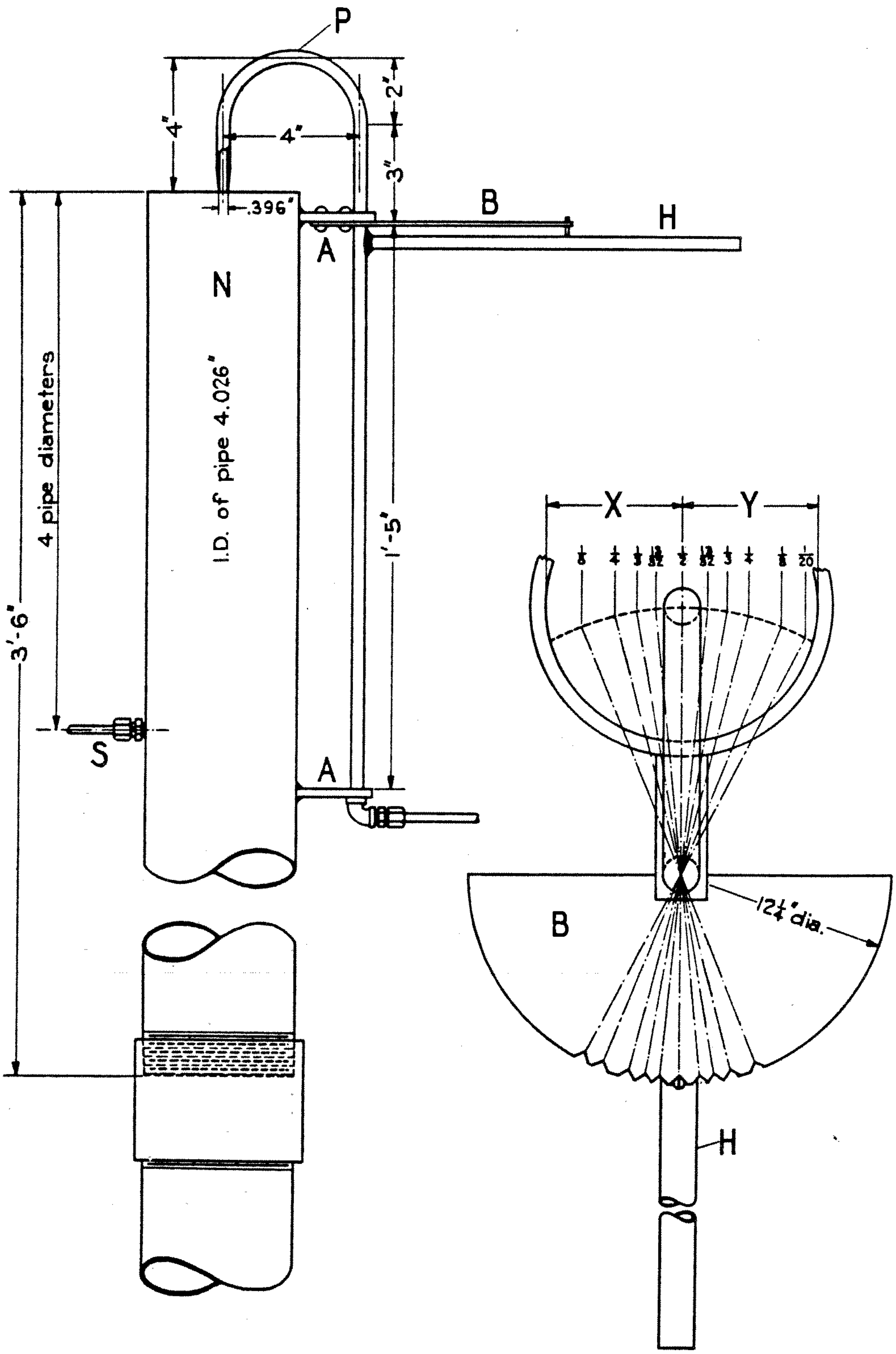
TABLE 32[1].—*Delivery rates[2] corresponding to different side static pressures at a distance of 4 pipe diameters from opening of pipe*

Side-static pressure		Diameter of opening, inches								
Mercury, inches	Pounds per square inch	1	2	3	4	5	6	8	10	12
		Open flow, M cubic feet per day								
5	..	704	2,820	6,340	11,300	17,600	25,300	45,100	70,400	101,000
5.5	..	714	2,860	6,430	11,400	17,900	25,700	45,700	71,400	103,000
6	3	725	2,900	6,530	11,600	18,100	26,100	46,400	72,600	104,000
6.5	..	735	2,940	6,620	11,800	18,400	26,500	47,000	73,500	106,000
7	..	745	2,980	6,710	11,900	18,600	26,800	47,700	74,500	107,000
7.5	..	754	3,020	6,790	12,100	18,900	27,100	48,300	75,400	109,000
8	4	764	3,060	6,880	12,200	19,100	27,500	48,900	76,400	110,000
8.5	..	775	3,100	6,980	12,400	19,400	27,900	49,600	77,500	112,000
9	..	784	3,140	7,060	12,500	19,600	28,200	50,200	78,400	113,000
9.5	..	795	3,180	7,160	12,700	19,900	28,600	50,900	79,500	114,000
10	5	805	3,220	7,250	12,900	20,100	29,000	51,500	80,500	116,000
11	..	825	3,300	7,430	13,200	20,600	29,700	52,800	82,500	119,000
12	6	845	3,380	7,610	13,500	21,100	30,400	54,100	84,500	122,000
13	..	865	3,460	7,790	13,800	21,600	31,100	55,400	86,500	125,000
14	7	885	3,540	7,970	14,200	22,100	31,900	56,600	88,500	127,000
15	..	906	3,630	8,160	14,500	22,700	32,600	58,000	90,600	130,000
16	8	926	3,710	8,340	14,800	23,200	33,300	59,300	92,600	133,000
17	..	945	3,780	8,510	15,100	23,600	34,000	60,500	94,500	136,000
18	9	966	3,870	8,700	15,500	24,200	34,800	61,800	96,600	139,000
19	..	986	3,950	8,880	15,800	24,700	35,500	63,100	98,600	142,000
20	10	1,013	4,050	9,120	16,200	25,300	36,500	64,800	101,000	146,000
22	11	1,055	4,220	9,500	16,900	26,400	38,000	67,500	106,000	152,000
24	12	1,095	4,380	9,860	17,500	27,400	39,400	70,100	110,000	158,000
26	13	1,137	4,550	10,200	18,200	28,400	40,900	72,800	114,000	164,000
28	14	1,178	4,710	10,600	18,800	29,500	42,400	75,400	118,000	170,000
30	15	1,218	4,870	11,000	19,500	30,500	43,800	78,000	123,000	175,000
..	16	1,260	5,040	11,300	20,200	31,500	45,400	80,600	126,000	181,000
..	18	1,343	5,370	12,100	21,500	33,600	48,300	86,000	134,000	193,000
..	20	1,424	5,700	12,800	22,800	35,600	51,300	91,100	142,000	205,000
..	25	1,629	6,520	14,700	26,100	40,700	58,600	104,000	163,000	235,000
..	30	1,834	7,340	16,500	29,300	45,900	66,000	117,000	183,000	..
..	35	2,041	8,170	18,400	32,700	51,000	73,500	131,000	204,000	..
..	40	2,245	8,980	20,200	35,900	56,100	80,800	144,000	225,000	..
..	45	2,450	9,800	22,100	39,200	61,300	88,200	157,000	245,000	..
..	50	2,657	10,600	23,900	42,500	66,400	95,700	170,000	..	..
..	60	3,067	12,300	27,600	49,100	76,700	110,000	196,000	..	..
..	70	3,476	13,900	31,300	55,600	86,900	125,000	222,000	..	..
..	80	3,887	15,500	35,000	62,200	97,200	140,000	249,000	..	..
..	90	4,298	17,200	38,700	68,800	107,000	155,000	..	..	..
..	100	4,708	18,800	42,400	75,300	118,000	169,000	..	..	..
..	120	5,531	22,100	49,800	88,500	138,000	199,000	..	..	..
..	150	6,762	27,000	60,900	108 000	169,000	..	..	..	..
..	200	8,810	35,200	79,300	141,000	220,000	..	..	..	..

[1] Based on Reid's formula. See Reid, Walter, Open-Flow Determinations of Gas Wells: Western Gas, November 1929, p. 15.

[2] Rates of flow in this table expressed in M cu. ft. per 24 hours based on a pressure of 14.7 lb. per sq. in., a temperature of 60°F., and a specific gravity of 0.6.

at a distance from the wall equivalent to one third the internal diameter of the pipe is shown by *A* and *B* (fig. 44). Curves *A* and *B* indicate variation in pressures on the two sides of the center position in the discharge opening of the pipe. Rates of flow corresponding to different impact pressures as obtained from the commonly used Pitot-tube tables are shown by *C* (fig. 44).



N, 4-inch pipe nipple; P, Pitot tube; A, steel supporting arms; B, notched semicircular tin plate; H, handle welded to Pitot tube; X and Y, positions each side of center position; S, side static pressure connection

FIGURE 40.—Set-up of equipment for calibration of a Pitot tube to measure gas-delivery rates

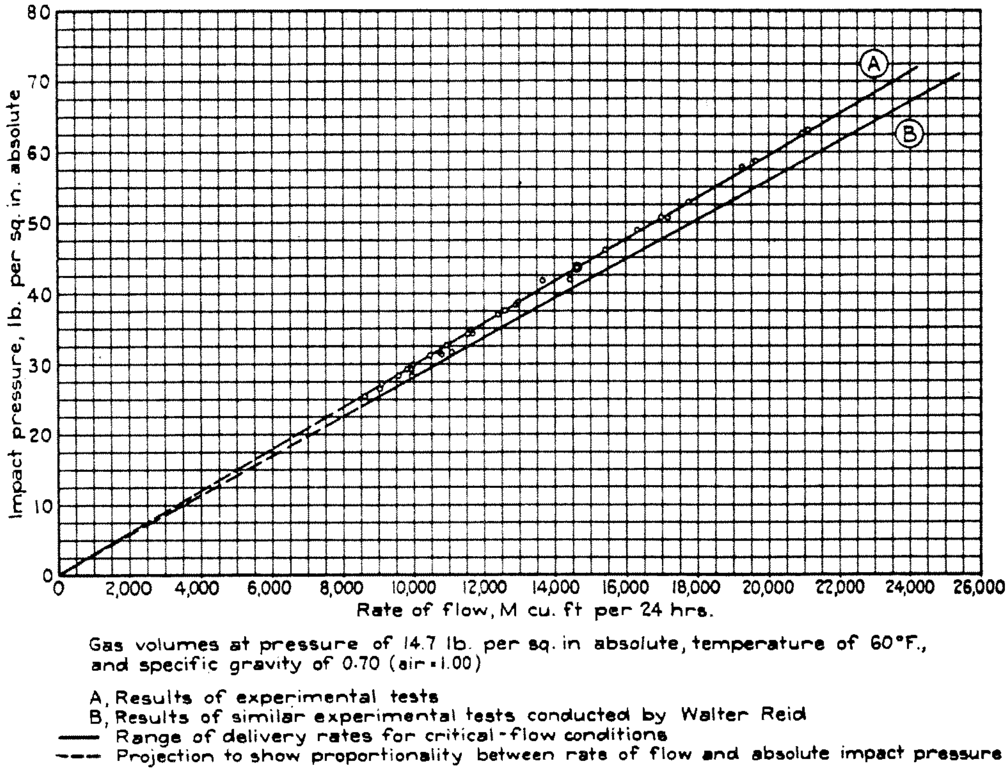


FIGURE 41.—Relationship between impact pressure and delivery rate of gas for *critical* flow with tip of Pitot tube at center of discharge opening of pipe

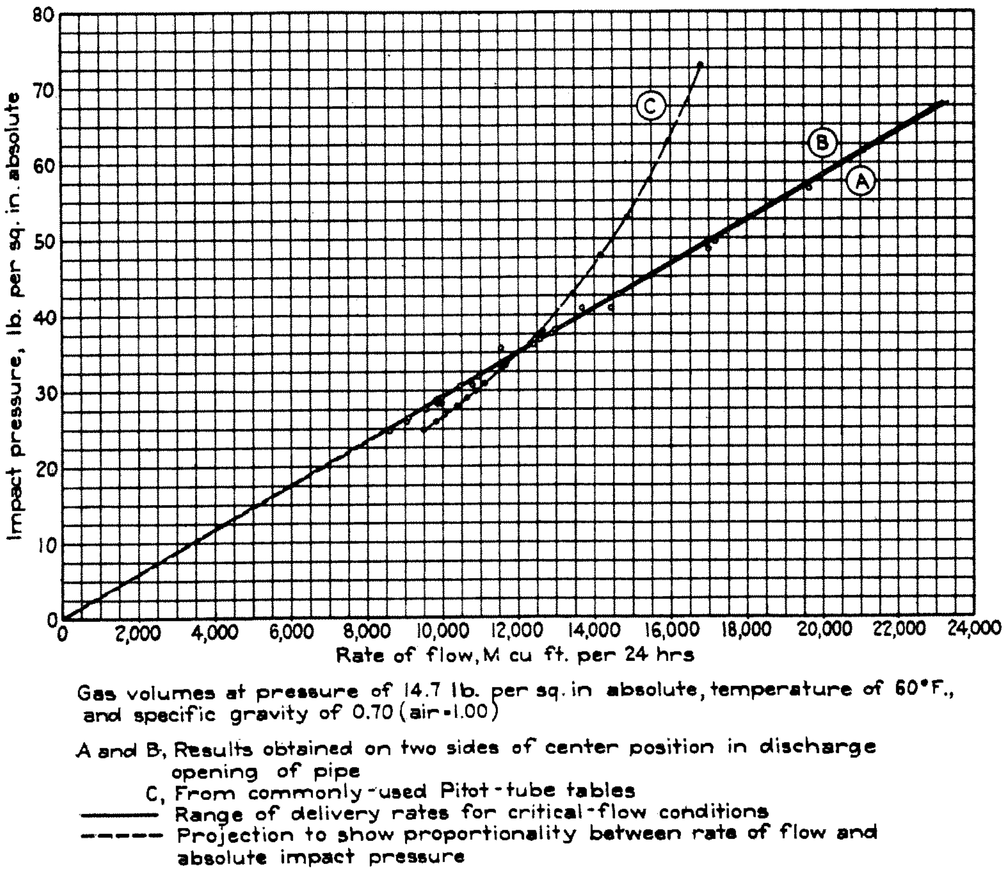
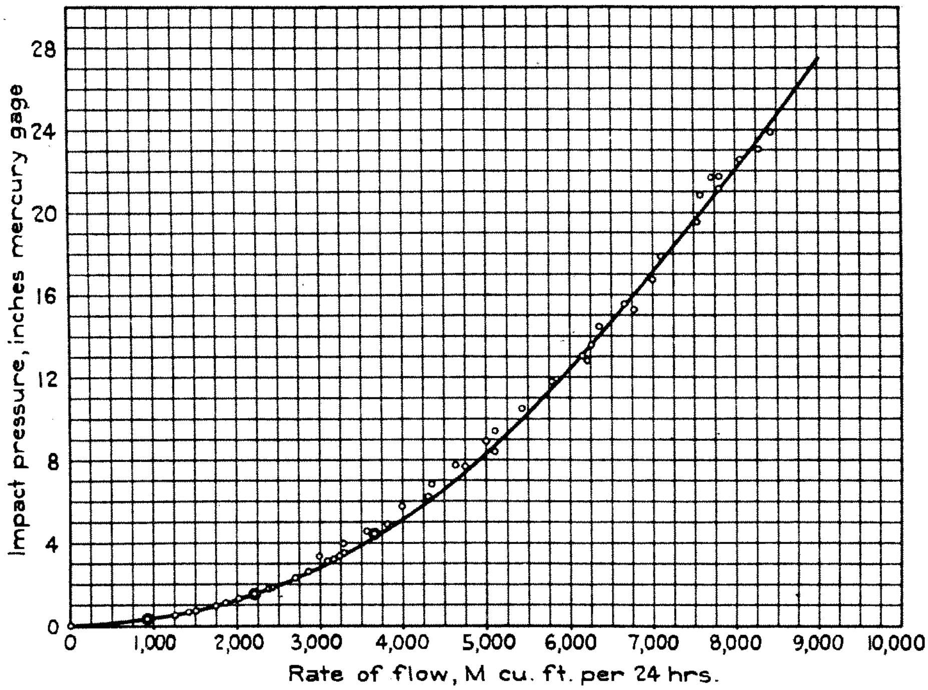
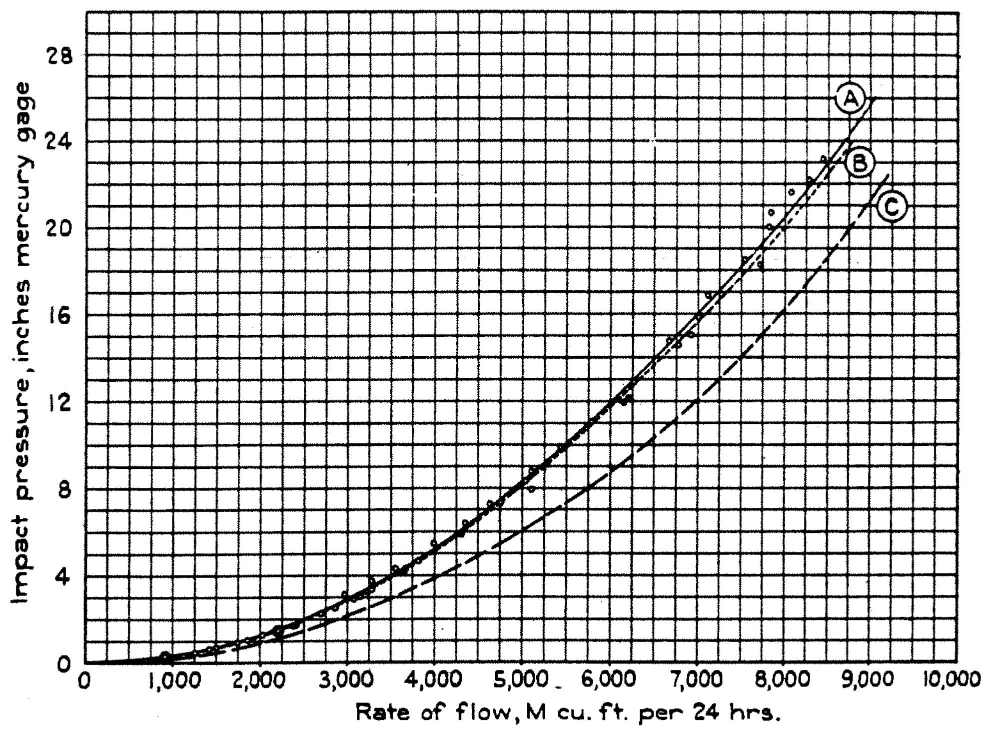


FIGURE 42.—Relationship between impact pressure and delivery rate of gas for *critical* flow with tip of Pitot tube at distance from inside wall equivalent to one-third internal diameter of pipe



Gas volumes at pressure of 14.7 lb. per sq. in. absolute, temperature of 60°F., and specific gravity of 0.70 (air = 1.00)

FIGURE 43.—Relationship between impact pressure and delivery rate of gas for *noncritical* flow with tip of Pitot tube at center of discharge opening of pipe



Gas volumes at pressure of 14.7 lb. per sq. in absolute, temperature of 60°F., and specific gravity of 0.70 (air = 1.00)

A and B, Results obtained on two sides of center position in discharge opening of pipe
C, From commonly-used Pitot-tube tables

FIGURE 44.—Relationship between impact pressure and delivery rate of gas for *noncritical* flow with tip of Pitot tube at a distance from inside wall equivalent to one-third internal diameter of pipe

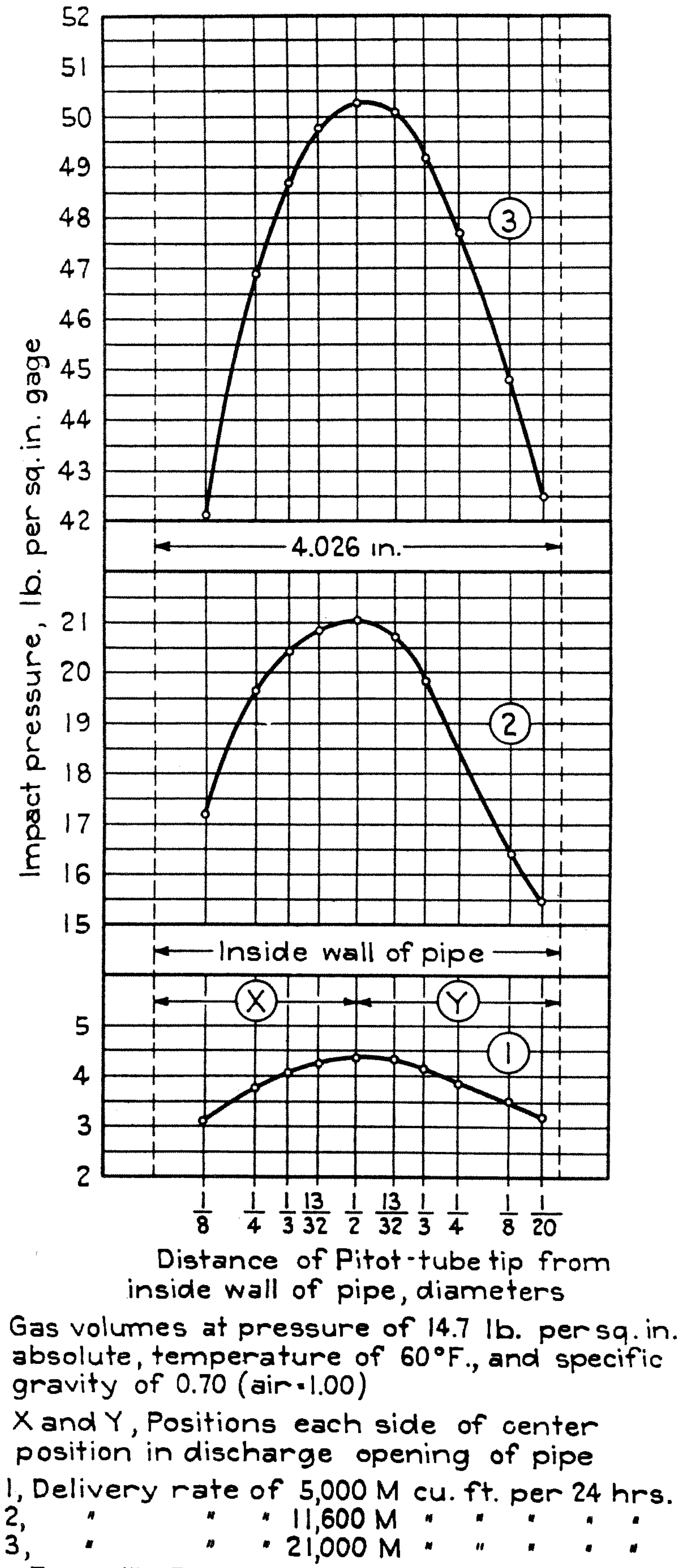
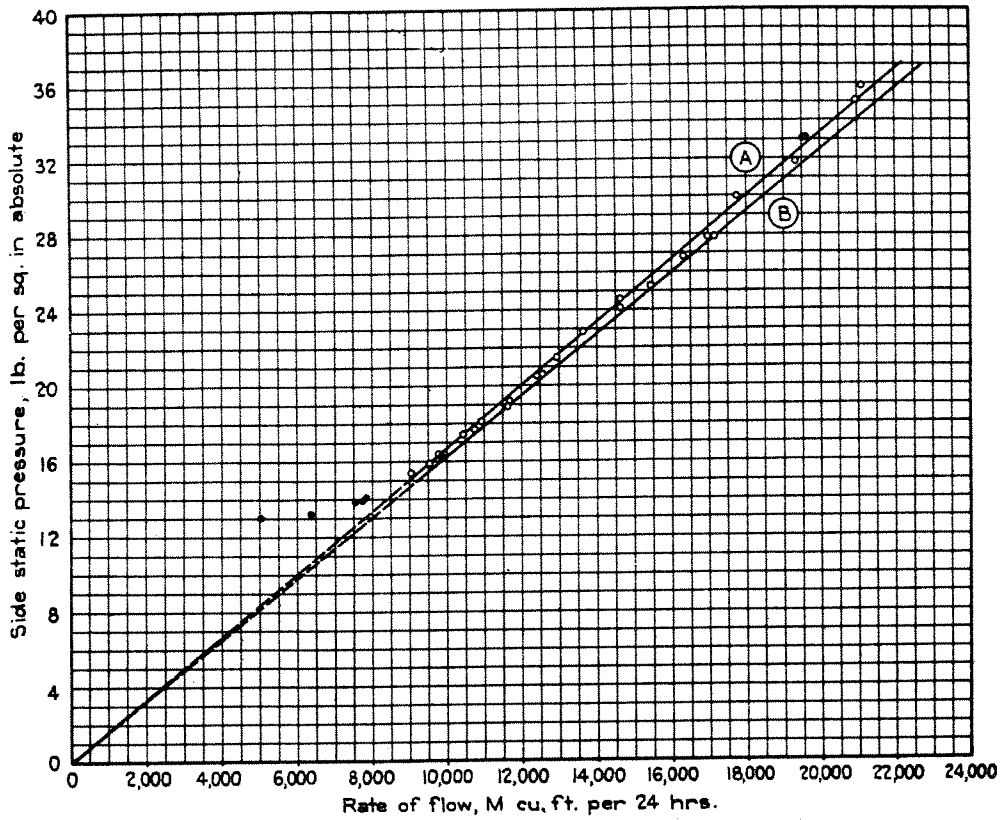


FIGURE 45.—Pressure-traverse curves showing variation of impact pressures across plane of opening of discharge pipe for different gas-delivery rates

A study of the data and comparisons shown in figures 41, 42, 43, and 44 emphasizes possible discrepancies in interpreting the delivery rate from natural-gas wells if the factors governing the measurement of gas deliveries with Pitot tubes are not thoroughly understood. The data show that if the gage pressure measured by the impact element of a Pitot tube is greater than 15 pounds per square inch the rate of flow is approximately directly proportional to the impact pressure, expressed in terms of absolute pressure; or, the



Gas volumes at pressure of 14.7 lb. per sq. in. absolute, temperature of 60°F., and specific gravity of 0.70 (air = 1.00)

A, Results of experimental tests
B, Results of similar experimental tests conducted by Walter Reid
—— Range of delivery rates for critical-flow conditions
--- Projection to show proportionality between rate of flow and absolute side static pressure

Pressure connection at distance of four pipe diameters from discharge end of pipe

FIGURE 46.—Relationship between side-static pressure and delivery rate for flow of gas through 4-inch pipe

rate of flow is approximately proportional to the absolute static pressure of the flow plus the velocity pressure of the gas stream.

Comparison of the relationships between the rate of flow and the impact pressure under critical and noncritical flow conditions for the one-third pipe-diameter position of the Pitot-tube tip on each side of the center position showed a variation between rates of flow corresponding to different impact pressures, as illustrated in figures 42 and 44. Although it is possible that some discrepancy in experimental observations could result from inability to locate the Pitot-tube tip at an exact predetermined distance from the inside wall of the pipe it is believed that variations such as those illustrated in figures 42 and 44 were caused by the sensitivity of velocity distribution in the gas stream to conditions upstream from the Pitot-tube installation. The influence of the sensitivity of velocity also is shown by the variation in pressures registered at different points in the plane of the opening of the discharge pipe and equidistant from the wall of the pipe at any definite delivery rate. Pressure-traverse curves showing the variation in impact pressure for delivery rates of 21,000,000, 11,600,000 and 5,000,000 cubic feet of gas per 24 hours are given in figure 45. The maximum impact pressure for each delivery rate was approximately at the center of the discharge opening of the pipe. The pressure-traverse curves in

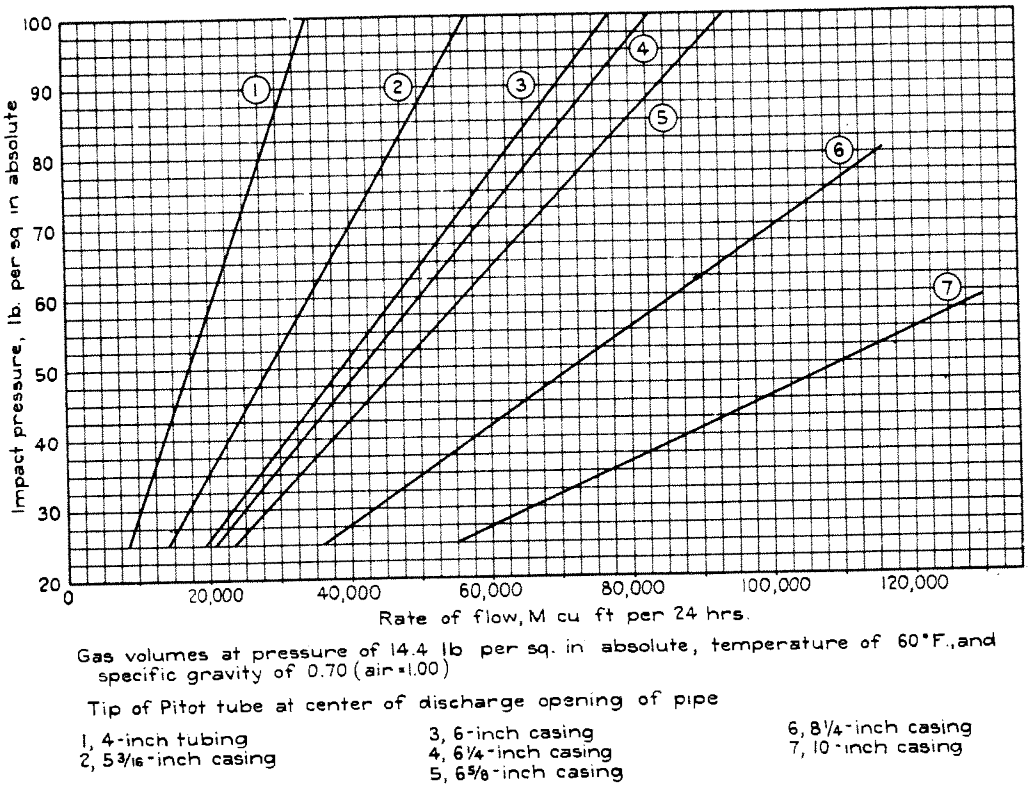


FIGURE 47.—Relationship between impact pressure and rate of gas delivery through different sizes of casing and tubing under conditions of *critical* flow

figure 45 also illustrate changes between pressure at different points in the plane of the opening that occurred for the different delivery rates.

The relationship between rate of flow and side-static pressure obtained from the special tests on the 4-inch pipe is shown by *A* (fig. 46). The rate of flow was directly proportional (approximately) to the absolute static pressure throughout a large part of the measurement range. Comparative results obtained by Reid are shown by *B* and agree fairly well with the results of the authors' special study.

Charts to facilitate calculation of gas-delivery rates from observations with Pitot tubes are given in figures 47 and 48. Delivery rates corresponding to different impact pressures for various sizes of pipe, based upon the special tests with the 4-inch pipe and upon the assumption that the rate of flow is directly proportional to the square of the diameter of the discharge opening through which the gas flows, are given graphically for critical-flow conditions in figure 47 and for noncritical flow conditions in figure 48. The tubing and casing sizes indicated in figures 47 and 48 refer to pipes with internal diameter as given in table 39. In using the charts, differences in internal diameter of pipes of the same nominal size but of different weight should be taken into account.

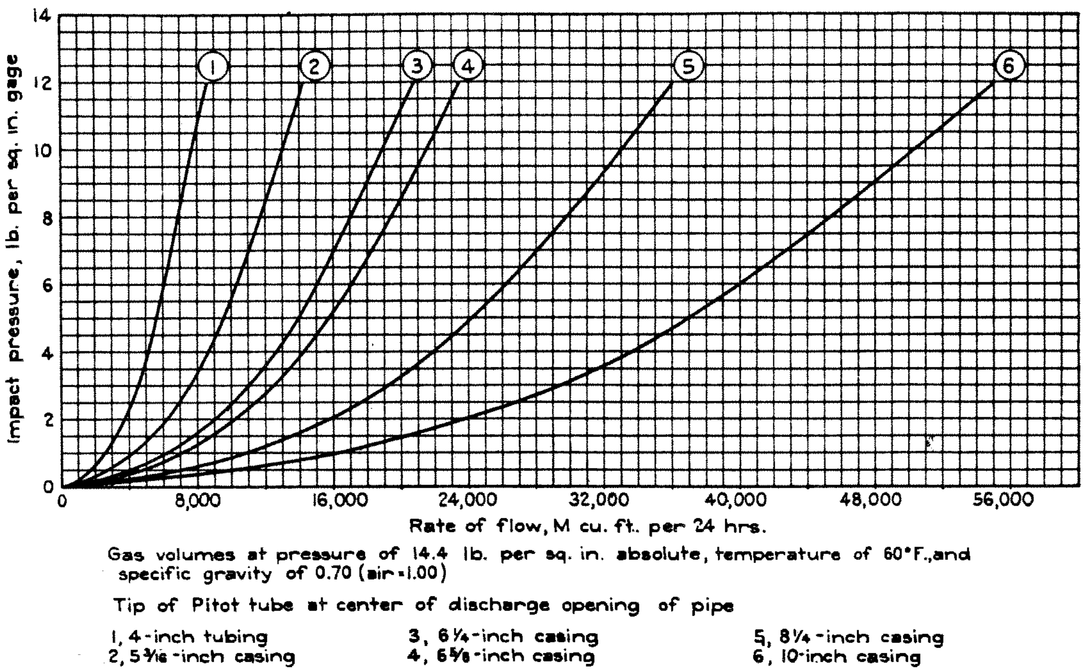


FIGURE 48.—Relationship between impact pressure and rate of gas delivery through different sizes of casing and tubing under conditions of *noncritical* flow

APPENDIX 5. COMPUTING PRESSURES AT THE SAND IN A GAS WELL

Experimental observations during back-pressure tests of gas wells are obtained at the wellhead, and the absolute shut-in pressures in the sand and the absolute back pressures at the sand in the well bore are computed from the wellhead observations to interpret delivery capacities of gas wells under different pressure conditions. Routine computations of back-pressure test data can be facilitated by using charts or tables covering a wide range of pressure-flow conditions. Charts that can be used in calculations of back-pressure test data are given by Pierce and Rawlins.[52] Since the publication of the charts tables have been devised by the authors for use in routine calculations from back-pressure data and generally are preferable to the charts.

[52] Pierce, H. R., and Rawlins, E. L., The Study of a Fundamental Basis for Controlling and Gaging Natural-Gas Wells; Part I, Computing the Pressure at the Sand in a Gas Well: Rept. of Investigations 2929, Bureau of Mines, 1929, 13 pp.

The notation used in the formulas for computing pressures at the sand in a gas well from volume and pressure observations at the wellhead is:

P_w = pressure at the wellhead when a well is flowing, pounds per square inch absolute;
P_c = pressure at the wellhead when a well is shut in, pounds per square inch absolute;
P_1 = pressure at the wellhead plus the pressure drop in the producing string due to friction, pounds per square inch absolute;
P_s = pressure at the sand, pounds per square inch absolute (absolute pressure at the wellhead, plus the pressure drop due to friction, plus the pressure due to the weight of the gas column);
P_f = formation or "shut-in" pressure in the sand, pounds per square inch absolute (absolute pressure at the wellhead when the well is shut in, plus the pressure due to the weight of the gas column);
Q = delivery rate, cubic feet per 24 hours, at 14.4 pounds per square inch and 60° F., assuming an average flowing temperature of 80° F. in the producing "string" of casing or tubing (it is assumed that 80° F. represents an average temperature in the producing string; the actual variation from this assumed condition will not create any considerable error in computation of pressures);
d = internal diameter of the producing string, inches;
G = specific gravity of gas (air = 1.00);
L = average length of gas column, feet;
R = combined factor selected from Weymouth's formula [53] for flow of gas through pipe = $\sqrt{P_1^2 - P_w^2}$ (this factor is discussed later in this appendix);
e = base of Napierian logarithms = 2.71828;
F = correction factor for density due to pressure variation in the flowing column of gas (this factor is explained later in this appendix).

PRESSURE CONDITIONS IN GAS WELLS

WELL SHUT IN

If a well is shut in and no gas is flowing the absolute shut-in pressure in the sand (P_f) equals the absolute pressure at the wellhead (P_c) plus the pressure due to the weight of the gas column. If there is no flow from the well there is no pressure drop due to friction in the producing string; consequently, $P_1 = P_c$. Thus, if a well is shut in the only factors to be considered in determining the absolute "shut-in" pressure in the sand are the absolute pressure at the wellhead and the pressure due to the weight of the static column of gas from the sand to the wellhead.

WELL PRODUCING

If a gas well is equipped with tubing so installed that the annular space in the casing string is open from the gas formation to the wellhead there is a static column of gas in the tubing and a static column of gas between the tubing and the casing when the respective strings are closed at the wellhead. If gas is being produced from the casing there is a static column of gas in the closed tubing and the absolute working pressure or back pressure at the sand P_s equals the absolute pressure in the closed tubing at the wellhead plus the pressure due to the weight of the static column of gas in the tubing. If gas is

[53] Weymouth, T. R., Problems in Natural-Gas Engineering: Trans. Am. Soc. Mech. Eng., vol. 34, 1912, pp. 185-231.

being produced from the tubing there is a static column of gas in the annular space between the tubing and the casing, and the absolute working pressure at the sand P_s equals the absolute pressure in the closed casing at the wellhead plus the pressure due to the weight of the static column of gas in the annular space.

When gas is being produced from a well that is not equipped with tubing, or from one in which a packer is installed on the lower end of the tubing, the above-described method of computing P_s cannot be used because there is no continuous column of static gas from the sand to the wellhead. It then becomes necessary to use the relation that the absolute working pressure at the sand equals the absolute pressure on the producing string at the wellhead P_w, plus the friction drop in the producing string, plus the pressure due to the weight of the moving gas column between the sand and the wellhead. Therefore, P_w+friction drop in the producing string$=P_1$, and P_1+pressure due to the weight of the gas column$=P_s$.

Thus, if a well is so equipped that two strings are open between the sand and the wellhead and gas is flowing through only one string, the only factors required for determining the absolute working pressure at the sand P_s are the absolute pressure in the closed string at the wellhead and the pressure due to the weight of the static column of gas in the closed string. The factors to be considered in determining the pressures at the sand if working pressures are gaged only on the flow string at the wellhead are the absolute working pressure at the wellhead, the friction drop in the string due to flow, and the pressure due to the weight of the moving column of gas. In computations the friction drop in the pipe due to flow, expressed in pounds per square inch, is considered first and added to the absolute pressure at the top of the producing string P_w; thus, P_w+friction drop in producing string$=P_1$. The pressure due to the weight of the column of gas, expressed in pounds per square inch, is determined next and is added to P_1 to give the absolute pressure at the sand P_s; that is, P_1+pressure due to the weight of the column of gas$=P_s$.

DETERMINING PRESSURES AT THE SAND IN A GAS WELL FROM TABLES

SAMPLE CALCULATIONS

Tables 33, 34, 35, 36, 37, and 38 have been prepared to facilitate calculation of pressures at the sand in a gas well from pressure and volume observations made at the wellhead. Tables, formulas, and conditions are explained in detail later in this appendix in the section entitled "Discussion of tables." Methods of using the tables to calculate results of back-pressure tests are illustrated by the following examples in which the data are:

Depth of well=3,000 feet.
Specific gravity of gas=0.6 (air=1.00).
Casing, 6⅝ inches in diameter (6.652 inches I. D.) and set 2,990 feet below the surface of the ground.
Flow string, 3,000 feet of 4-inch tubing (4.026 inches I. D.) packed off at the wellhead.
"Shut-in" pressure at the wellhead, 940 pounds per square inch absolute.
Operating pressure at the wellhead on the static 6⅝-inch casing when gas

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TABLE 33.—*Equivalent GL of producing string (GL for 1-inch tubing equivalent to GL of producing string)*

GL of producing string	Nominal size and internal diameter of producing string, inches											
	1¼ 1.380	1½ 1.610	2 2.041	2½ 2.469	3 3.068	3½ 3.548	4 4.026	5 3/16 5.192	6 6.065	6¼ 6.287	6⅝ 6.652	8¼ 8.249
	Equivalent *GL* of producing string											
600	139	61	17	6.2	2.0	0.90	0.46	0.12	0.05	0.04	0.03	0.01
700	162	71	20	7.3	2.3	1.10	.54	.14	.06	.05	.04	.01
800	185	81	23	8.3	2.6	1.2	.61	.16	.07	.06	.04	.01
900	208	92	26	9.4	2.9	1.4	.69	.18	.08	.06	.05	.02
1,000	232	102	29	10	3.3	1.5	.77	.20	.09	.07	.05	.02
1,100	255	112	32	11	3.6	1.7	.84	.22	.09	.08	.06	.02
1,200	278	122	34	12	3.9	1.8	.92	.24	.10	.09	.06	.02
1,300	301	132	37	14	4.2	2.0	1.0	.26	.11	.09	.07	.02
1,400	324	143	40	15	4.6	2.1	1.1	.28	.12	.10	.07	.02
1,500	347	153	43	16	4.9	2.3	1.2	.30	.13	.11	.08	.03
1,600	371	163	46	17	5.2	2.4	1.2	.32	.14	.11	.08	.03
1,700	394	173	49	18	5.6	2.6	1.3	.34	.15	.12	.09	.03
1,800	417	183	52	19	5.9	2.7	1.4	.36	.16	.13	.09	.03
1,900	440	193	55	20	6.2	2.9	1.5	.38	.16	.14	.10	.03
2,000	463	204	57	21	6.5	3.0	1.5	.40	.17	.14	.11	.03
2,100	486	214	60	22	6.9	3.2	1.6	.42	.18	.15	.11	.04
2,200	510	224	63	23	7.2	3.3	1.7	.43	.19	.16	.12	.04
2,300	533	234	66	24	7.5	3.5	1.8	.45	.20	.16	.12	.04
2,400	556	244	69	25	7.8	3.6	1.8	.47	.21	.17	.13	.04
2,500	579	255	72	26	8.2	3.8	1.9	.49	.22	.18	.13	.04
2,600	602	265	75	27	8.5	3.9	2.0	.51	.22	.19	.14	.04
2,700	625	275	78	28	8.8	4.1	2.1	.53	.23	.19	.14	.05
2,800	649	285	80	29	9.2	4.2	2.1	.55	.24	.20	.15	.05
2,900	672	295	83	30	9.5	4.4	2.2	.57	.25	.21	.15	.05
3,000	695	305	86	31	9.8	4.5	2.3	.59	.26	.21	.16	.05
3,100	718	316	89	32	10	4.7	2.4	.61	.27	.22	.16	.05
3,200	741	326	92	33	10	4.8	2.5	.63	.28	.23	.17	.05
3,300	764	336	95	34	11	5.0	2.5	.65	.28	.24	.17	.06
3,400	788	346	98	35	11	5.1	2.6	.67	.29	.24	.18	.06
3,500	811	356	101	36	11	5.3	2.7	.69	.30	.25	.18	.06
3,600	834	367	103	37	12	5.4	2.8	.71	.31	.26	.19	.06
3,700	857	377	106	39	12	5.6	2.8	.73	.32	.26	.20	.06
3,800	880	387	109	40	12	5.7	2.9	.75	.33	.27	.20	.06
3,900	903	397	112	41	13	5.9	3.0	.77	.34	.28	.21	.07
4,000	927	407	115	42	13	6.0	3.1	.79	.35	.28	.21	.07

Internal diameter of 1-inch tubing = 1.049 inches.

TABLE 34.—*Values of* $\sqrt{P_1^2 - P_w^2}$ *or* R *corresponding to equivalent GL of producing strings*

Equivalent *GL* of producing string	Rate of flow, M cubic feet per 24 hours																	
	100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850	900	950
	$R = \sqrt{P_1^2 - P_w^2}$																	
0.01	0.18	0.27	0.36	0.45	0.54	0.63	0.72	0.81	0.90	0.99	1.08	1.17	1.26	1.35	1.44	1.53	1.62	1.71
.02	.25	.38	.51	.63	.76	.89	1.01	1.14	1.27	1.40	1.52	1.65	1.78	1.90	2.03	2.16	2.28	2.41
.03	.31	.47	.62	.78	.93	1.09	1.24	1.40	1.55	1.71	1.86	2.02	2.18	2.33	2.49	2.64	2.80	2.95
.04	.36	.54	.72	.90	1.08	1.26	1.44	1.62	1.80	1.98	2.16	2.34	2.52	2.70	2.88	3.06	3.24	3.42
.05	.40	.60	.80	1.00	1.20	1.41	1.61	1.81	2.01	2.21	2.41	2.61	2.81	3.02	3.22	3.42	3.62	3.82
.06	.44	.66	.88	1.10	1.32	1.54	1.76	1.98	2.20	2.42	2.64	2.86	3.08	3.30	3.52	3.74	3.96	4.18
.07	.48	.71	.95	1.19	1.42	1.66	1.90	2.14	2.38	2.61	2.85	3.09	3.33	3.56	3.80	4.04	4.27	4.51
.08	.51	.76	1.01	1.27	1.52	1.78	2.03	2.28	2.54	2.79	3.04	3.30	3.55	3.80	4.06	4.31	4.57	4.82
.09	.54	.81	1.08	1.35	1.62	1.89	2.16	2.42	2.70	2.96	3.24	3.50	3.77	4.04	4.31	4.58	4.85	5.12
.10	.57	.85	1.14	1.42	1.70	1.98	2.27	2.55	2.84	3.12	3.41	3.69	3.97	4.26	4.54	4.82	5.11	5.40
.11	.60	.89	1.19	1.49	1.78	2.08	2.38	2.68	2.98	3.27	3.57	3.87	4.17	4.46	4.77	5.06	5.36	5.66
.12	.62	.93	1.24	1.55	1.87	2.18	2.49	2.80	3.11	3.42	3.73	4.04	4.36	4.67	4.98	5.29	5.60	5.91
.13	.65	.97	1.29	1.62	1.94	2.26	2.59	2.91	3.23	3.56	3.88	4.20	4.53	4.85	5.18	5.50	5.83	6.15
.14	.67	1.00	1.34	1.67	2.01	2.35	2.68	3.03	3.35	3.69	4.02	4.36	4.71	5.03	5.38	5.72	6.05	6.39
.15	.69	1.04	1.39	1.73	2.08	2.43	2.78	3.12	3.47	3.82	4.18	4.53	4.86	5.21	5.57	5.92	6.27	6.60
.16	.72	1.08	1.43	1.80	2.15	2.51	2.87	3.23	3.59	3.95	4.30	4.66	5.02	5.38	5.74	6.10	6.46	6.82
.17	.74	1.11	1.48	1.85	2.22	2.59	2.96	3.33	3.70	4.07	4.44	4.81	5.19	5.56	5.92	6.29	6.67	7.03
.18	.76	1.14	1.52	1.90	2.28	2.66	3.05	3.43	3.81	4.19	4.57	4.95	5.33	5.71	6.09	6.47	6.85	7.25
.19	.78	1.18	1.57	1.96	2.35	2.74	3.14	3.52	3.92	4.31	4.70	5.09	5.48	5.88	6.27	6.66	7.05	7.45
.20	.80	1.20	1.61	2.01	2.41	2.81	3.22	3.62	4.02	4.42	4.82	5.22	5.63	6.03	6.43	6.83	7.23	7.63
.22	.84	1.26	1.68	2.10	2.52	2.95	3.37	3.79	4.21	4.63	5.06	5.47	5.90	6.32	6.74	7.16	7.58	8.00
.24	.88	1.32	1.76	2.20	2.64	3.07	3.51	3.95	4.39	4.83	5.27	5.71	6.17	6.61	7.05	7.49	7.93	8.37
.26	.92	1.37	1.83	2.29	2.75	3.20	3.66	4.12	4.58	5.03	5.49	5.95	6.41	6.87	7.33	7.78	8.24	8.70
.28	.95	1.43	1.91	2.38	2.85	3.32	3.80	4.27	4.75	5.23	5.70	6.18	6.66	7.13	7.60	8.08	8.56	9.03
.30	.98	1.47	1.97	2.46	2.95	3.44	3.93	4.42	4.91	5.41	5.90	6.39	6.88	7.39	7.87	8.36	8.86	9.35
.32	1.02	1.52	2.03	2.54	3.05	3.56	4.07	4.57	5.08	5.58	6.09	6.60	7.11	7.63	8.14	8.63	9.14	9.65
.34	1.05	1.57	2.10	2.62	3.15	3.67	4.19	4.72	5.24	5.76	6.29	6.81	7.33	7.86	8.38	8.91	9.43	9.96
.36	1.08	1.62	2.16	2.69	3.23	3.77	4.31	4.85	5.38	5.93	6.47	7.00	7.54	8.08	8.62	9.16	9.70	10.2
.38	1.11	1.66	2.22	2.77	3.32	3.87	4.43	4.98	5.53	6.09	6.65	7.19	7.75	8.30	8.87	9.42	9.97	10.5
.40	1.14	1.70	2.27	2.84	3.41	3.97	4.54	5.11	5.68	6.25	6.81	7.39	7.95	8.52	9.09	9.67	10.2	10.8
.45	1.20	1.81	2.41	3.01	3.62	4.21	4.81	5.42	6.02	6.62	7.24	7.83	8.43	9.05	9.65	10.2	10.8	11.4
.50	1.27	1.91	2.54	3.18	3.81	4.45	5.08	5.72	6.35	6.99	7.62	8.26	8.90	9.53	10.2	10.8	11.4	12.1
.55	1.33	2.00	2.67	3.34	4.00	4.67	5.34	6.01	6.67	7.34	8.01	8.68	9.33	10.0	10.7	11.3	12.0	12.7
.60	1.39	2.09	2.79	3.48	4.18	4.87	5.57	6.27	6.97	7.66	8.35	9.05	9.75	10.4	11.1	11.8	12.5	13.2
.65	1.45	2.17	2.90	3.62	4.35	5.07	5.80	6.52	7.24	7.97	8.70	9.42	10.1	10.9	11.6	12.3	13.0	13.7
.70	1.50	2.26	3.00	3.76	4.50	5.26	6.01	6.76	7.52	8.26	9.02	9.77	10.5	11.3	12.0	12.8	13.5	14.3
.75	1.56	2.34	3.12	3.90	4.68	5.45	6.22	7.01	7.79	8.56	9.35	10.1	10.9	11.7	12.5	13.2	14.0	14.8
.80	1.61	2.41	3.21	4.01	4.81	5.62	6.42	7.24	8.04	8.84	9.65	10.4	11.2	12.0	12.8	13.6	14.4	15.2
.85	1.66	2.48	3.31	4.14	4.97	5.80	6.63	7.45	8.28	9.12	9.95	10.7	11.6	12.4	13.2	14.1	14.9	15.7
.90	1.71	2.56	3.41	4.26	5.11	5.97	6.82	7.67	8.53	9.38	10.2	11.1	11.9	12.8	13.6	14.5	15.3	16.2
.95	1.75	2.63	3.50	4.38	5.25	6.12	7.00	7.88	8.76	9.64	10.5	11.4	12.2	13.1	14.0	14.9	15.7	16.6
1.00	1.80	2.69	3.59	4.49	5.38	6.28	7.19	8.08	8.98	9.88	10.8	11.7	12.6	13.5	14.3	15.2	16.2	17.0

TABLE 34.—*Values of* $\sqrt{P_1^2 - P_w^2}$ *or R corresponding to equivalent GL of producing strings*—Continued

Equivalent *GL* of producing string	Rate of flow, M cubic feet per 24 hours																	
	100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850	900	950
	$R = \sqrt{P_1^2 - P_w^2}$																	
1.10	1.88	2.82	3.76	4.70	5.66	6.60	7.54	8.49	9.43	10.3	11.3	12.2	13.2	14.1	15.0	16.0	16.9	17.9
1.2	1.96	2.94	3.94	4.91	5.90	6.88	7.80	8.86	9.85	10.8	11.8	12.8	13.7	14.7	15.7	16.7	17.7	18.7
1.3	2.05	3.08	4.10	5.13	6.15	7.17	8.20	9.22	10.2	11.3	12.3	13.3	14.3	15.4	16.4	17.4	18.4	19.5
1.4	2.12	3.18	4.24	5.32	6.37	7.45	8.51	9.57	10.6	11.7	12.7	13.8	14.8	15.9	17.0	18.0	19.1	20.2
1.5	2.20	3.30	4.40	5.50	6.60	7.70	8.80	9.90	11.0	12.1	13.2	14.3	15.4	16.5	17.6	18.7	19.8	20.9
1.6	2.27	3.40	4.54	5.69	6.82	7.96	9.10	10.2	11.3	12.5	13.6	14.7	15.9	17.0	18.1	19.3	20.4	21.5
1.7	2.34	3.51	4.68	5.85	7.02	8.19	9.38	10.5	11.7	12.9	14.0	15.2	16.4	17.5	18.7	19.9	21.1	22.2
1.8	2.41	3.62	4.82	6.03	7.23	8.43	9.64	10.8	12.0	13.2	14.5	15.7	16.9	18.1	19.3	20.5	21.7	22.9
1.9	2.47	3.71	4.96	6.20	7.43	8.66	9.91	11.1	12.3	13.6	14.8	16.1	17.3	18.5	19.8	21.0	22.3	23.5
2.0	2.54	3.80	5.09	6.36	7.63	8.90	10.1	11.4	12.7	13.9	15.2	16.5	17.7	19.0	20.3	21.5	22.8	24.1
2.2	2.66	4.00	5.32	6.66	8.00	9.32	10.6	12.0	13.3	14.6	16.0	17.3	18.6	20.0	21.3	22.6	24.0	25.3
2.4	2.78	4.17	5.56	6.95	8.36	9.75	11.1	12.5	13.9	15.3	16.7	18.0	19.5	20.8	22.2	23.6	25.0	26.4
2.6	2.90	4.35	5.80	7.25	8.70	10.1	11.6	13.0	14.5	15.9	17.4	18.8	20.3	21.7	23.2	24.6	26.1	27.5
2.8	3.00	4.51	6.01	7.52	9.02	10.5	12.0	13.5	15.0	16.5	18.0	19.5	21.0	22.5	24.1	25.6	27.1	28.5
3.0	3.11	4.67	6.23	7.78	9.33	10.9	12.4	14.0	15.5	17.1	18.7	20.2	21.8	23.4	24.9	26.5	28.0	29.6
3.2	3.22	4.82	6.43	8.04	9.64	11.2	12.8	14.5	16.1	17.7	19.3	20.9	22.5	24.1	25.7	27.3	28.9	30.6
3.4	3.32	4.97	6.63	8.28	9.94	11.6	13.3	14.9	16.6	18.2	19.8	21.5	23.2	24.9	26.5	28.2	29.8	31.5
3.6	3.41	5.11	6.81	8.52	10.2	11.9	13.6	15.3	17.0	18.7	20.4	22.2	23.8	25.6	27.3	29.0	30.7	32.4
3.8	3.50	5.25	7.00	8.75	10.5	12.2	14.0	15.7	17.5	19.2	21.0	22.8	24.5	26.3	28.0	29.8	31.5	33.3
4.0	3.59	5.40	7.19	8.98	10.8	12.6	14.4	16.2	18.0	19.7	21.6	23.4	25.2	27.0	28.8	30.6	32.4	34.2
4.2	3.68	5.52	7.36	9.21	11.0	12.9	14.7	16.6	18.4	20.2	22.1	23.9	25.8	27.6	29.4	31.3	33.1	35.0
4.4	3.77	5.66	7.54	9.42	11.3	13.2	15.1	17.0	18.8	20.8	22.6	24.5	26.4	28.3	30.1	32.1	33.9	35.8
4.6	3.85	5.78	7.71	9.63	11.5	13.5	15.4	17.4	19.3	21.2	23.2	25.0	27.0	28.9	30.8	32.7	34.7	36.6
4.8	3.93	5.90	7.88	9.85	11.8	13.7	15.7	17.7	19.7	21.6	23.6	25.6	27.5	29.5	31.5	33.4	35.4	37.4
5.0	4.02	6.02	8.03	10.1	12.0	14.0	16.1	18.1	20.1	22.1	24.1	26.1	28.1	30.1	32.2	34.2	36.2	38.2
5.5	4.21	6.32	8.43	10.5	12.6	14.7	16.8	18.9	21.1	23.2	25.3	27.4	29.5	31.6	33.7	35.8	37.9	40.0
6.0	4.40	6.60	8.80	11.0	13.2	15.4	17.6	19.8	22.0	24.2	26.4	28.6	30.8	33.0	35.2	37.4	39.6	41.8
6.5	4.59	6.88	9.17	11.5	13.7	16.0	18.3	20.6	22.9	25.2	27.5	29.8	32.1	34.4	36.7	39.0	41.3	43.6
7.0	4.76	7.13	9.51	11.9	14.3	16.7	19.0	21.4	23.8	26.2	28.6	30.9	33.3	35.7	38.1	40.5	42.8	45.2
7.5	4.92	7.38	9.84	12.3	14.7	17.2	19.7	22.1	24.6	27.1	29.5	32.0	34.4	36.9	39.3	41.8	44.3	46.7
8.0	5.08	7.62	10.1	12.7	15.2	17.8	20.4	22.9	25.4	27.9	30.5	33.0	35.6	38.1	40.6	43.1	45.7	48.2
8.5	5.23	7.85	10.4	13.1	15.7	18.3	20.9	23.5	26.2	28.8	31.4	34.0	36.6	39.2	41.9	44.5	47.1	49.7
9.0	5.39	8.09	10.8	13.5	16.2	18.8	21.6	24.3	26.9	29.6	32.3	35.0	37.7	40.4	43.1	45.8	48.6	51.2
9.5	5.53	8.31	11.0	13.8	16.6	19.4	22.1	24.9	27.7	30.4	33.2	36.0	38.7	41.5	44.3	47.1	49.8	52.6
10	5.69	8.52	11.4	14.2	17.0	19.8	22.7	25.6	28.4	31.2	34.1	36.9	39.7	42.6	45.4	48.3	51.1	54.0
11	5.93	8.89	11.9	14.9	17.8	20.8	23.8	26.8	29.6	32.7	35.7	38.5	41.5	44.5	47.4	50.4	53.4	56.3
12	6.22	9.33	12.4	15.5	18.6	21.8	24.9	28.0	31.1	34.2	37.3	40.4	43.5	46.6	49.7	52.8	56.0	59.0
13	6.49	9.73	13.0	16.2	19.5	22.7	26.0	29.2	32.4	35.7	38.9	42.1	45.4	48.6	51.9	55.1	58.4	61.6
14	6.73	10.1	13.5	16.8	20.2	23.5	26.9	30.3	33.7	37.0	40.3	43.7	47.1	50.4	53.8	57.2	60.6	64.0
15	6.96	10.4	13.9	17.4	20.9	24.4	27.8	31.3	34.8	38.3	41.7	45.2	48.7	52.1	55.7	59.1	62.6	66.1
16	7.20	10.8	14.4	18.0	21.6	25.2	28.8	32.4	36.0	39.6	43.1	46.8	50.3	54.0	57.5	61.1	64.8	68.3
17	7.40	11.1	14.8	18.5	22.2	25.9	29.6	33.3	37.0	40.7	44.4	48.1	51.8	55.6	59.2	63.0	66.6	70.3

TABLE 34.—*Values of* $\sqrt{P_1^2 - P_w^2}$ *or R corresponding to equivalent GL of producing strings*—Continued

Equivalent *GL* of producing string	Rate of flow, M cubic feet per 24 hours																	
	100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850	900	950
	$R = \sqrt{P_1^2 - P_w^2}$																	
18	7.62	11.4	15.3	19.0	22.9	26.7	30.5	34.3	38.1	41.9	45.7	49.5	53.3	57.2	61.0	64.8	68.6	72.4
19	7.83	11.7	15.6	19.6	23.5	27.4	31.3	35.2	39.1	43.1	47.0	50.8	54.8	58.7	62.7	66.5	70.5	74.3
20	8.03	12.0	16.0	20.1	24.1	28.1	32.1	36.1	40.1	44.1	48.1	52.2	56.2	60.3	64.3	68.2	72.3	76.3
22	8.43	12.6	16.9	21.0	25.3	29.5	33.7	37.9	42.1	46.3	50.6	54.8	59.0	63.2	67.4	71.7	75.8	80.1
24	8.80	13.2	17.6	22.0	26.4	30.8	35.3	39.6	44.0	48.4	52.8	57.2	61.6	66.0	70.5	74.9	79.2	83.6
26	9.16	13.7	18.3	22.9	27.5	32.1	36.7	41.2	45.8	50.4	55.0	59.6	64.1	68.7	73.3	77.8	82.4	87.1
28	9.51	14.3	19.0	23.8	28.5	33.3	38.1	42.8	47.6	52.3	57.1	61.8	66.6	71.3	76.1	80.8	85.7	90.4
30	9.85	14.7	19.7	24.6	29.5	34.4	39.3	44.2	49.1	54.2	59.0	63.9	68.8	73.9	78.8	83.7	88.6	93.5
32	10.2	15.2	20.3	25.4	30.5	35.6	40.6	45.7	50.8	55.9	61.0	66.0	71.1	76.2	81.3	86.3	91.4	96.5
34	10.5	15.7	21.0	26.2	31.5	36.7	42.0	47.2	52.4	57.7	62.9	68.2	73.4	78.7	83.8	89.1	94.3	99.6
36	10.8	16.2	21.6	26.9	32.3	37.7	43.1	48.5	53.9	59.3	64.6	70.0	75.4	80.8	86.3	91.7	97.0	102
38	11.1	16.6	22.2	27.7	33.2	38.7	44.3	49.8	55.3	60.9	66.4	72.0	77.5	83.0	88.7	94.2	99.6	105
40	11.4	17.0	22.7	28.4	34.1	39.7	45.4	51.1	56.8	62.5	68.1	73.8	79.5	85.2	90.9	96.7	102	108
45	12.0	18.1	24.1	30.1	36.1	42.1	48.1	54.2	60.2	66.2	72.3	78.3	84.3	90.5	96.5	102	108	114
50	12.7	19.1	25.4	31.8	38.1	44.5	50.8	57.2	63.5	70.0	76.3	82.6	89.0	95.3	102	108	114	121
55	13.3	20.0	26.6	33.3	39.9	46.7	53.3	59.9	66.6	73.3	79.9	86.6	93.2	99.9	106	113	120	126
60	13.9	20.9	27.9	34.8	41.8	48.8	55.7	62.7	69.7	76.6	83.5	90.6	97.5	104	111	118	125	132
65	14.5	21.7	29.0	36.2	43.4	50.7	58.0	65.2	72.4	79.7	86.9	94.2	101	109	116	123	130	138
70	15.0	22.6	30.1	37.6	45.1	52.7	60.2	67.7	75.2	82.8	90.3	97.8	105	113	120	128	135	143
75	15.6	23.4	31.1	38.9	46.7	54.5	62.3	70.1	77.8	85.6	93.3	101	109	117	124	132	140	148
80	16.1	24.1	32.2	40.2	48.2	56.3	64.3	72.3	80.3	88.3	96.5	104	112	120	128	137	145	153
85	16.6	24.9	33.1	41.4	49.7	58.0	66.2	74.5	82.8	91.2	99.5	108	116	124	132	141	149	157
90	17.0	25.6	34.1	42.6	51.1	59.7	68.1	76.7	85.3	93.8	102	111	119	128	136	145	153	162
95	17.5	26.3	35.0	43.7	52.5	61.3	70.0	78.8	87.5	96.3	105	114	122	131	140	149	157	166
100	18.0	27.0	36.0	45.0	54.0	63.0	72.0	80.9	89.8	98.9	108	117	126	135	144	153	162	171
110	18.8	28.3	37.7	47.1	56.5	65.9	75.3	84.9	94.3	103	113	122	132	141	150	160	170	179
120	19.7	29.5	39.4	49.1	59.0	68.9	78.7	88.5	98.5	108	118	128	138	148	157	167	177	187
130	20.5	30.7	41.0	51.2	61.4	71.7	82.0	92.2	102	113	123	133	143	154	164	174	184	195
140	21.2	31.8	42.4	53.2	63.7	74.5	85.0	95.7	106	117	127	138	148	159	170	180	191	202
150	22.0	33.0	44.0	55.0	66.0	77.0	88.0	99.0	110	121	132	143	154	165	176	187	198	209
160	22.7	34.1	45.5	56.8	68.1	79.6	90.9	102	114	125	136	147	159	170	182	193	205	216
170	23.4	35.1	46.9	58.5	70.3	81.9	93.8	105	117	129	140	152	164	175	187	199	211	222
180	24.1	36.1	48.1	60.3	72.4	84.4	96.5	108	120	132	144	156	168	180	193	205	217	229
190	24.8	37.2	49.6	62.0	74.2	86.7	99.1	111	124	136	149	161	173	186	198	211	223	235
200	25.4	38.1	50.8	63.5	76.3	88.9	101	114	127	140	152	165	178	190	203	216	229	242
225	27.0	40.4	53.9	67.3	80.8	94.4	108	121	135	148	162	175	189	202	216	229	242	256
250	28.4	42.7	56.8	71.0	85.2	99.5	114	128	142	156	170	185	199	213	228	241	256	270
275	29.8	44.7	59.6	74.4	89.3	104	119	134	149	164	179	193	208	224	238	253	268	283
300	31.1	46.7	62.3	77.7	93.3	109	124	140	155	171	187	202	218	233	249	264	280	295
325	32.4	48.6	64.8	80.9	97.1	113	130	145	162	178	194	210	226	243	259	275	291	308
350	33.6	50.4	67.2	84.1	101	118	135	151	168	185	202	219	236	252	269	286	303	320
375	34.8	52.3	69.7	87.1	104	122	139	157	174	191	209	226	244	261	279	296	314	331

TABLE 34.—*Values of* $\sqrt{P_1^2 - P_w^2}$ *or R corresponding to equivalent GL of producing strings*—Continued

Equivalent *GL* of producing string	Rate of flow, M cubic feet per 24 hours																	
	100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850	900	950
	$R = \sqrt{P_1^2 - P_w^2}$																	
400	35.9	54.0	71.9	89.8	108	126	144	162	180	197	216	234	252	270	287	306	324	341
425	37.0	55.5	74.0	92.6	111	130	148	167	185	204	222	240	259	278	296	315	333	352
450	38.1	57.2	76.2	95.3	114	133	152	172	190	210	229	248	267	286	305	324	343	362
475	39.1	58.7	78.3	98.0	117	137	156	176	196	215	235	254	274	293	313	333	352	372
500	40.2	60.3	80.4	100	120	140	161	181	201	221	241	261	281	302	322	342	362	382
550	42.1	63.2	84.2	105	126	147	168	189	210	232	253	274	295	316	337	358	379	400
600	44.0	66.0	88.0	110	132	154	176	198	220	242	264	286	308	330	352	374	396	418
650	45.8	68.8	91.7	115	138	160	183	206	229	252	275	298	321	344	366	390	413	436
700	47.6	71.3	95.2	119	143	167	190	214	238	262	285	309	333	357	381	404	429	452
750	49.2	73.9	98.5	123	148	172	197	222	246	271	295	320	344	369	394	418	443	468
800	50.9	76.3	102	127	152	178	203	229	254	280	305	331	356	381	406	432	458	483
850	52.4	78.5	105	131	157	183	209	237	262	288	314	340	366	392	419	445	471	497
900	53.9	80.8	108	135	162	188	215	242	269	296	323	350	377	404	431	458	485	512
950	55.3	83.0	111	138	166	193	221	249	277	304	332	359	387	415	443	470	498	526
1,000	56.8	85.2	114	142	171	199	228	256	285	313	341	369	398	427	455	483	512	540
1,100	59.5	89.3	119	149	179	209	238	268	298	328	357	387	417	447	477	506	536	566
1,200	62.2	93.3	124	155	187	218	249	280	311	342	373	404	436	466	498	528	560	591
1,300	64.8	97.1	129	162	194	227	259	291	324	356	389	421	453	486	518	550	583	615
1,400	67.3	101	135	168	202	235	269	303	337	370	403	437	471	505	538	572	606	639
1,500	69.5	104	139	174	209	244	278	313	347	383	417	452	487	522	557	591	627	661
1,600	71.8	107	143	179	215	251	287	323	359	395	431	467	502	538	574	610	646	683
1,700	74.0	111	148	185	222	259	296	333	370	407	444	481	518	555	593	629	666	703
1,800	76.3	114	152	190	228	267	305	342	381	420	457	495	533	571	609	648	686	725
1,900	78.3	117	157	196	235	274	313	352	392	430	470	509	548	587	626	666	705	743
2,000	80.3	120	160	200	241	281	321	361	401	441	481	523	563	603	643	682	724	763
2,100	82.4	123	164	206	247	288	330	371	412	453	495	535	577	618	660	701	742	783
2,200	84.3	126	168	210	252	295	337	379	421	463	506	547	589	632	675	716	758	800
2,300	86.1	129	172	215	259	301	345	388	431	473	517	560	603	647	689	732	776	818
2,400	88.0	132	176	220	264	308	352	396	440	484	529	572	616	660	705	748	792	838
2,500	89.8	135	180	225	269	314	359	404	449	494	540	583	629	673	718	763	808	853
2,600	91.7	138	183	229	275	321	367	412	459	503	550	596	642	688	733	779	826	872
2,700	93.3	140	187	233	280	326	373	420	466	513	560	606	653	701	746	793	840	887
2,800	95.1	143	190	238	285	333	381	428	476	523	571	619	666	713	762	808	856	904
2,900	96.8	145	194	242	290	339	387	436	483	532	581	629	677	726	774	823	872	920
3,000	98.5	147	197	246	295	345	394	443	492	541	590	640	688	738	787	836	887	936
3,200	102	153	204	254	305	356	407	458	508	560	610	661	712	763	813	865	915	967
3,400	105	157	209	262	314	366	419	471	524	576	629	680	733	785	838	890	942	995
3,600	108	162	216	270	324	377	431	485	539	593	648	702	755	810	863	917	971	1,025
3,800	111	166	222	277	332	387	443	498	553	609	664	720	775	830	887	942	997	1,053
4,000	113	170	227	284	340	397	456	512	568	625	681	738	795	853	910	967	1,023	1,080

TABLE 35.—*Pressure drop in producing string due to friction corresponding to different values of R*

$\sqrt{P_1^2 - P_w^2}$ or R	Pressure at wellhead, P_w, pounds per square inch absolute																	
	15	25	50	75	100	125	150	175	200	225	250	275	300	325	350	375	400	450
	Pressure drop in producing string due to friction, lb. per sq. in.																	
5	1	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..
10	3	2	1	1	1	..	..	..	..	..	..	..	..	..	..	..	..	..
15	6	4	2	2	1	1	1	1	1	..	..	..	..	..	..	..	..	..
20	10	6	4	3	2	2	1	1	1	1	1	1	1	..	..	..	..	..
25	14	10	6	4	3	2	2	2	2	1	1	1	1	1	1	1	1	1
30	19	14	8	6	4	4	3	2	2	2	2	1	1	1	1	1	1	1
35	23	18	11	8	6	5	4	3	3	3	2	2	2	2	1	1	1	1
40	28	22	14	10	8	6	5	4	4	3	3	3	3	2	2	2	2	2
45	32	27	17	13	10	8	7	6	5	4	4	4	3	3	3	2	2	2
50	37	31	21	15	12	10	8	7	6	5	5	4	4	4	3	3	3	3
60	47	40	28	21	17	14	12	10	9	8	7	6	6	5	5	5	4	4
70	57	49	36	28	22	18	15	13	12	10	9	9	8	7	7	6	6	5
80	66	59	44	35	28	23	20	17	15	14	12	11	10	9	9	8	8	7
90	76	68	53	42	35	29	25	22	19	17	16	14	13	12	11	10	10	9
100	86	78	62	50	41	35	30	26	24	21	19	17	16	15	14	13	12	11
110	96	88	71	58	49	41	36	32	28	25	23	21	19	18	17	16	15	13
120	106	98	80	67	56	48	42	37	33	30	27	25	23	21	20	19	18	16
130	116	107	89	75	64	55	48	43	38	35	32	29	27	25	23	22	20	18
140	126	117	99	84	72	62	55	49	44	40	36	33	31	29	27	25	24	21
150	136	127	108	93	80	70	62	55	50	45	41	38	35	33	31	29	27	24
160	146	137	118	102	88	78	69	62	56	51	47	43	40	37	35	32	30	28
170	156	147	127	111	97	86	77	69	62	57	52	48	45	42	39	36	34	31
180	166	157	137	120	106	94	84	76	69	63	58	53	50	46	43	41	38	35
190	176	167	146	129	115	102	92	83	76	69	64	59	55	51	48	45	43	38
200	186	177	156	139	124	111	100	91	83	76	70	65	60	56	53	50	47	43
210	196	186	166	148	133	119	108	98	90	83	76	71	66	62	58	55	52	47
220	206	196	176	157	142	128	116	106	97	90	82	77	72	67	63	60	57	51
230	216	206	185	167	151	137	125	114	105	97	89	83	78	73	69	65	62	56
240	226	216	195	177	160	146	134	122	112	104	96	90	84	78	75	70	66	60
250	235	226	205	186	169	155	142	131	120	111	104	97	90	85	80	75	71	65

TABLE 35.—*Pressure drop in producing string due to friction corresponding to different values of R*—Continued

$\sqrt{P_1^2 - P_w^2}$ or R	Pressure at wellhead, P_w, pounds per square inch absolute																	
	500	550	600	650	700	750	800	850	900	950	1,000	1,100	1,200	1,300	1,400	1,500	2,000	2,500
	Pressure drop in producing string due to friction, lb. per sq. in.																	
5	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..
10	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..
15	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..
20	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..
25	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..
30	1	1	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..	..
35	1	1	1	1	1	1	1	1	1	..	..	..	..	..	..	..	..	..
40	1	1	1	1	1	1	1	1	1	1	1	1	1	..	..	..	..	..
45	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	..	..
50	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	..
60	3	3	3	2	2	2	2	2	2	2	2	2	1	1	1	1	1	..
70	5	4	4	4	3	3	2	2	2	2	2	2	2	2	2	2	1	1
80	6	6	5	4	4	4	4	3	3	3	2	2	2	2	2	2	1	1
90	8	7	7	6	6	6	4	4	4	4	4	3	3	3	3	3	2	2
100	10	9	8	7	7	6	6	6	5	5	5	4	4	4	4	3	2	2
110	12	11	10	9	8	8	7	6	6	5	5	5	5	5	4	4	3	2
120	14	13	12	11	10	9	9	8	8	7	7	6	6	6	5	5	4	3
130	16	15	14	13	12	10	11	9	8	8	8	6	7	6	5	6	4	3
140	19	18	16	15	14	13	12	11	10	10	10	8	8	7	6	7	5	4
150	22	20	18	17	16	15	14	13	12	11	11	10	9	9	8	8	6	4
160	24	22	20	19	18	16	16	14	14	13	13	11	10	10	9	9	6	5
170	28	25	23	22	20	18	17	16	16	15	15	13	11	11	10	10	7	6
180	32	28	26	24	22	20	20	18	18	16	16	14	13	12	11	11	7	6
190	35	31	29	27	26	23	22	20	20	18	17	16	14	14	12	12	8	7
200	38	34	32	30	28	26	24	23	22	20	19	18	16	15	14	13	10	8
210	42	38	36	32	30	28	26	25	24	22	21	20	18	17	16	14	11	9
220	46	42	39	36	33	31	29	28	26	25	23	22	19	18	17	15	12	10
230	50	46	42	40	36	34	32	30	28	27	26	24	22	20	18	18	13	11
240	54	50	46	43	39	38	35	33	31	30	28	26	23	22	20	19	14	12
250	59	54	50	46	43	42	38	36	34	32	31	28	25	24	22	21	16	13

TABLE 35.—*Pressure drop in producing string due to friction corresponding to different values of R*—Continued

$\sqrt{P_1^2 - P_w^2}$ or R	Pressure at wellhead, P_w, pounds per square inch absolute																	
	15	25	50	75	100	125	150	175	200	225	250	275	300	325	350	375	400	450
	Pressure drop in producing string due to friction, lb. per sq. in.																	
260	245	236	215	196	179	163	150	139	128	119	111	103	96	91	86	81	77	70
270	255	246	225	205	188	172	159	147	136	126	118	110	103	97	92	87	83	75
280	265	256	234	215	198	182	166	155	144	134	124	117	110	104	98	93	89	80
290	275	266	244	224	207	191	176	164	152	142	133	124	117	110	104	99	94	85
300	285	276	254	234	216	199	186	172	161	150	141	131	124	117	110	105	100	91
310	295	286	264	243	226	209	194	181	169	158	149	139	131	124	117	112	106	96
320	305	296	274	253	236	219	203	189	178	166	156	146	139	131	123	118	112	101
330	315	306	284	263	245	228	212	198	186	174	164	155	146	138	131	124	119	108
340	325	316	294	273	254	237	222	207	194	183	172	162	153	145	138	131	125	114
350	335	326	304	283	264	247	231	216	203	191	180	170	161	153	145	138	131	120
360	345	336	314	292	273	256	240	225	211	199	188	178	168	160	152	145	137	126
370	355	346	323	302	283	265	249	234	220	208	196	185	176	167	159	151	144	132
380	365	356	333	312	293	275	258	243	229	216	205	194	184	175	166	159	151	139
390	375	366	343	322	303	284	268	252	238	225	213	202	192	183	174	166	159	145
400	385	376	353	331	312	294	277	261	247	234	221	210	200	190	181	173	166	152
410	395	386	363	341	322	303	286	270	256	243	230	218	208	198	189	180	173	159
420	405	396	373	351	332	313	296	280	265	251	238	227	216	206	197	188	180	165
430	415	406	383	361	341	323	306	289	274	260	247	235	223	214	205	195	187	173
440	425	416	393	371	351	332	315	298	283	270	256	243	232	222	212	203	194	180
450	435	426	403	381	361	342	324	308	292	278	265	252	240	230	220	211	202	187
460	445	453	412	391	370	352	333	317	301	287	273	261	249	238	228	218	210	193
470	455	446	422	401	380	362	343	326	310	296	281	270	257	246	236	226	218	200
480	465	456	432	410	390	371	353	335	320	305	291	278	266	255	244	234	225	208
490	475	466	442	420	400	381	362	345	329	314	300	287	275	264	252	242	233	215
500	485	476	452	430	410	390	371	355	339	323	308	296	283	272	260	250	240	223
510	495	486	462	440	420	400	381	364	348	332	318	304	292	280	269	258	249	230
520	505	496	472	450	430	410	391	373	357	342	327	313	300	288	277	266	257	238
530	515	506	482	460	440	420	400	383	366	351	335	322	310	297	285	275	265	245
540	525	515	492	470	449	429	410	393	376	360	345	331	318	305	294	283	272	253
550	535	525	502	480	459	439	420	402	385	369	354	340	327	314	302	290	280	260

TABLE 35.—*Pressure drop in producing string due to friction corresponding to different values of R*—Continued

$\sqrt{P_1^2 - P_w^2}$ or R	Pressure at wellhead, P_w, pounds per square inch absolute																	
	500	550	600	650	700	750	800	850	900	950	1,000	1,100	1,200	1,300	1,400	1,500	2,000	2,500
	Pressure drop in producing string due to friction, lb. per sq. in.																	
260	63	59	54	50	46	45	41	39	36	34	33	30	27	25	24	22	16	14
270	68	63	58	54	50	48	44	42	39	37	36	32	30	27	25	24	18	15
280	73	67	62	58	54	51	47	44	42	40	38	34	32	29	27	25	20	16
290	78	71	66	62	58	54	50	47	45	43	40	37	34	31	29	28	21	17
300	83	76	70	66	62	58	54	51	48	46	43	40	36	33	31	30	22	18
310	88	81	75	70	66	61	58	54	52	49	46	42	38	35	33	31	24	19
320	93	86	80	75	70	65	62	57	55	52	49	45	41	38	35	33	25	20
330	99	91	85	80	74	70	65	61	58	55	52	48	43	40	38	35	27	22
340	105	96	90	84	78	74	69	65	62	58	55	50	46	43	40	38	29	23
350	110	101	95	88	83	78	73	69	65	62	59	53	49	46	43	40	30	24
360	115	107	100	93	87	82	77	72	68	66	63	56	52	49	45	42	32	26
370	122	112	105	97	91	86	81	76	72	69	66	59	55	52	47	45	34	27
380	128	118	111	103	96	90	85	80	76	73	70	63	58	54	50	47	36	29
390	134	124	116	109	101	95	90	84	80	76	73	66	61	56	52	49	38	30
400	140	130	121	114	106	100	94	89	84	80	76	70	64	59	55	51	39	31
410	147	136	126	120	111	105	98	94	88	84	81	73	67	62	58	54	42	33
420	153	142	131	125	116	110	103	98	92	88	85	76	70	65	62	57	44	35
430	159	148	138	130	122	115	108	102	97	91	88	80	74	69	64	60	46	37
440	166	154	144	135	127	120	112	107	102	96	92	84	78	72	67	63	48	38
450	173	160	150	140	133	125	117	111	106	100	96	88	81	75	70	66	50	40
460	180	167	157	146	138	130	122	116	111	105	100	92	85	79	73	69	52	42
470	187	174	163	152	144	135	127	121	115	110	105	96	88	82	76	72	54	44
480	193	180	169	159	150	141	133	126	119	114	109	99	92	85	80	75	57	46
490	200	187	175	165	155	146	138	131	124	119	113	103	95	88	82	77	59	48
500	207	194	181	171	161	152	143	136	129	123	117	107	99	92	87	80	61	50
510	215	201	188	177	167	157	149	141	134	128	122	112	103	95	90	83	64	51
520	222	208	195	183	173	163	154	146	139	133	126	117	107	99	93	86	67	54
530	230	215	201	189	179	169	159	151	144	138	131	121	111	103	96	90	69	56
540	236	221	208	195	185	175	164	157	149	143	136	125	115	107	100	94	72	58
550	243	228	214	201	190	180	170	162	154	147	141	130	120	111	105	97	74	60

TABLE 35.—*Pressure drop in producing string due to friction corresponding to different values of R*—Continued

$\sqrt{P_1^2 - P_w^2}$ or R	Pressure at wellhead, P_w, pounds per square inch absolute																	
	15	25	50	75	100	125	150	175	200	225	250	275	300	325	350	375	400	450
	Pressure drop in producing string due to friction, lb. per sq. in.																	
560	545	535	512	490	468	448	430	411	395	378	363	348	335	323	310	298	289	268
570	555	545	522	500	478	458	439	421	404	388	373	358	344	331	319	308	296	276
580	565	555	532	510	489	468	449	431	414	397	381	367	354	340	327	316	305	283
590	575	565	542	519	498	478	459	440	423	406	391	376	362	348	336	324	313	292
600	585	575	552	529	508	488	469	450	432	415	400	385	371	357	344	333	321	300
610	595	585	562	539	518	497	478	460	442	425	409	394	380	366	353	341	330	308
620	605	595	572	549	528	507	488	469	451	435	419	404	389	375	363	350	338	316
630	615	605	582	559	538	517	497	478	461	444	428	413	398	384	371	358	346	324
640	625	615	592	569	548	527	507	488	470	454	437	421	407	393	380	367	354	332
650	635	625	602	579	558	537	517	498	480	463	446	431	416	402	388	376	362	340
660	645	635	612	589	568	546	526	508	490	472	456	441	425	411	396	384	371	349
670	655	645	622	598	577	556	537	517	499	481	466	449	434	420	406	392	380	358
680	665	655	632	609	587	566	545	528	509	492	475	458	443	428	414	401	389	365
690	675	665	642	619	597	576	556	537	518	501	483	468	452	438	423	410	397	373
700	685	675	652	629	607	586	566	546	527	511	493	476	461	447	432	419	406	382
710	695	685	662	639	617	595	575	556	538	520	502	485	471	455	442	428	415	390
720	705	695	672	649	627	605	586	565	547	529	513	496	480	465	450	437	423	399
730	715	705	682	659	637	615	595	575	557	539	522	505	490	474	460	446	432	408
740	725	715	692	669	646	625	606	585	566	548	532	515	499	484	470	455	440	417
750	735	725	702	678	657	635	615	595	577	558	541	523	508	492	479	464	450	425
775	760	750	727	703	682	660	640	620	601	582	565	547	531	515	500	486	473	447
800	785	775	752	728	707	685	664	644	625	607	589	570	554	538	523	509	495	469
825	810	800	777	753	731	709	689	668	650	631	613	594	578	562	546	532	518	490
850	835	825	801	778	756	734	713	693	673	655	636	618	601	585	569	554	540	511
875	860	850	826	803	781	759	738	717	697	679	660	642	625	608	592	576	562	533
900	885	875	851	828	805	783	762	741	722	703	685	666	648	631	615	599	585	555
925	910	900	876	853	830	808	787	766	746	726	708	690	672	655	638	622	608	577
950	935	925	901	877	855	833	812	791	770	751	731	714	696	678	662	646	630	601
975	960	950	926	902	880	857	837	816	795	775	756	738	720	702	685	670	654	624
1,000	985	975	951	927	905	882	861	840	820	799	781	762	743	725	709	693	677	647

TABLE 35.—*Pressure drop in producing string due to friction corresponding to different values of R*—Continued

$\sqrt{P_1^2 - P_w^2}$ or R	Pressure at wellhead, P_w, pounds per square inch absolute																	
	500	550	600	650	700	750	800	850	900	950	1,000	1,100	1,200	1,300	1,400	1,500	2,000	2,500
	Pressure drop in producing string due to friction, lb. per sq. in.																	
560	251	235	221	208	196	185	176	167	160	152	146	135	124	115	108	101	76	62
570	258	241	228	215	203	192	182	172	165	158	150	139	128	118	111	104	79	63
580	265	249	235	222	209	198	188	178	170	162	155	143	132	122	114	107	82	65
590	273	257	241	229	215	205	194	184	175	168	160	147	136	128	118	112	85	68
600	281	264	248	235	222	211	200	190	181	173	165	152	142	132	122	115	88	70
610	289	271	256	241	229	216	206	196	187	178	171	157	145	135	125	120	91	72
620	296	278	263	248	235	222	211	201	193	183	176	162	150	139	130	123	94	75
630	304	286	270	255	241	229	217	207	198	190	181	167	154	144	134	126	97	77
640	312	294	277	262	247	235	223	214	204	194	187	172	160	148	138	130	100	80
650	320	301	285	269	255	242	230	220	210	200	192	177	165	152	143	134	103	83
660	328	309	292	276	262	248	236	226	215	206	198	182	169	157	147	138	106	86
670	335	318	298	283	268	256	242	232	221	212	204	187	174	162	151	143	109	88
680	344	325	308	290	276	261	249	238	227	218	209	193	179	167	156	147	112	91
690	352	332	314	297	283	268	256	244	233	224	214	198	184	172	160	150	116	93
700	360	340	321	305	290	275	262	250	240	230	220	203	188	175	165	154	119	95
710	369	347	330	312	296	282	269	256	246	235	226	209	193	180	170	159	122	99
720	376	356	336	320	304	289	275	263	252	241	231	214	198	185	174	163	126	101
730	385	364	345	327	310	296	282	270	259	247	238	220	204	190	178	168	128	103
740	393	372	352	335	319	303	289	277	265	253	243	225	209	195	183	172	132	107
750	402	380	360	342	326	310	296	283	271	260	250	231	215	200	187	176	136	110
775	423	400	380	362	344	328	314	300	287	276	265	246	229	213	200	188	145	116
800	443	420	400	381	363	347	331	317	303	292	280	260	242	225	212	199	154	125
825	464	442	420	400	382	366	350	334	320	308	296	275	256	239	225	212	163	133
850	486	462	440	420	400	385	367	351	338	324	312	290	271	253	238	223	173	141
875	508	484	460	440	420	404	385	370	355	340	328	305	285	266	250	235	182	149
900	529	505	480	459	439	423	403	387	372	358	345	320	300	280	263	248	192	157
925	550	526	503	481	460	441	422	405	390	375	361	337	314	295	276	262	202	165
950	574	548	523	500	479	461	442	424	408	393	379	353	330	310	291	275	213	175
975	596	570	545	520	500	480	461	443	427	411	396	370	345	328	305	288	224	183
1,000	618	590	565	541	520	500	480	463	445	430	413	386	361	339	320	302	236	193

is being delivered through the 4-inch tubing at the rate of 10,000,000 cubic feet per 24 hours, 891 pounds per square inch absolute.
Operating pressure at the wellhead on the flow string corresponding to a gas delivery rate of 10,000,000 cubic feet per 24 hours through the tubing, 867 pounds per square inch absolute.

TABLE 36.—*Correction factors F corresponding to ratios of P_w/P_1 to calculate pressure due to weight of moving gas column*

Ratio P_w/P_1	Correction factor F	Ratio P_w/P_1	Correction factor F
0	0.67	0.55	0.80
0.05	.67	.60	.82
.10	.67	.65	.84
.15	.68	.70	.86
.20	.69	.75	.88
.25	.70	.80	.90
.30	.71	.85	.93
.35	.73	.90	.95
.40	.74	.95	.98
.45	.76	1.00	1.00
.50	.78	..	..

Calculations are made from the data as follows:

1. Calculate P_f.
   a. $GL=0.6\times3{,}000=1{,}800$.
   b. From table 37, the pressure due to the weight of a column of gas corresponding to a shut-in wellhead pressure of 940 pounds per square inch absolute and a *GLF* of 1,800 is 60 pounds per square inch. In this case, *F* is unity and the pressure drop due to friction is zero because there is no gas flow.
   c. $P_f=940+60=1{,}000$ pounds per square inch absolute.
2. Calculate P_s, basing the calculations on data obtained from the 6⅝-inch casing. The pressure on the static column of gas between the 6⅝-inch casing and the 4-inch tubing can be gaged while gas is flowing through the 4-inch tubing. Under such conditions pressure P_s is equivalent to the absolute pressure gaged on the static column of gas at the wellhead plus the pressure due to the weight of the gas column and is determined as follows:

   a. $GL=0.6\times3{,}000=1{,}800$.
   b. From table 37 (since *F* is unity and the pressure drop due to friction is zero) the pressure due to the weight of the static column of gas in the annular space between the 6⅝-inch casing and the 4-inch tubing corresponding to a *GL* of 1,800 and a pressure at the wellhead of 891 pounds per square inch absolute is 58 pounds per square inch.
   c. $P_s=891+58=949$ pounds per square inch absolute.
3. Calculate P_s, basing the calculations on data obtained for the 4-inch producing string.

   a. $GL=0.6\times3{,}000=1{,}800$.
   b. From table 33, the equivalent *GL* of the producing string (the *GL* value which will allow a flow through 1-inch tubing equal to that through the producing string with its given *GL* value) is 1.4.
   c. From table 34 the value of *R* corresponding to a delivery rate of 10,000,000 cubic feet of gas per 24 hours and an equivalent *GL* of 1.4 is 212. Delivery rates in table 34 range from 100,000 to 950,000 cubic feet of gas per 24 hours. Since, as will be shown later in this appendix, the value of *R* is directly proportional to the delivery rate, values of *R* corresponding to higher delivery rates than listed in the table can be obtained by multiplying the value of *R* in the table by the ratio of delivery rates. For example, the ratio of 10,000,000 to 100,000 cubic feet per 24 hours is 100. Therefore, the value of *R* corresponding to a delivery rate of 10,000,000 cubic feet of gas per 24 hours is $100\times2.12=212$.

d. From table 35 the pressure drop in the flow string corresponding to an R of 212 and a wellhead pressure of 867 pounds per square inch absolute is 25 pounds per square inch.
e. $P_1 = P_w +$ pressure drop in producing string due to friction, or $P_1 = 867 + 25 = 892$ pounds per square inch.
f. The ratio, $P_w/P_1 = \frac{867}{892} = 0.97$.
g. From table 36 the value of F corresponding to a pressure ratio of 0.97 is 0.99.
h. $GLF = 1{,}800 \times 0.99 = 1{,}782$.
i. From table 37, the pressure due to the weight of a column of gas corresponding to a GLF of 1,782 and to a P_1 of 892 pounds per square inch absolute is 57 pounds per square inch.
j. $P_s = P_1 +$ pressure due to weight of column of gas, or $P_s = 892 + 57 = 949$ pounds per square inch absolute.

4. Calculate $(P_f^2 - P_s^2)$.
a. From table 38, $P_f^2 = (1{,}000)^2 = 1{,}000{,}000$ and $P_s^2 = (949)^2 = 900{,}600$.
b. Therefore $(P_f^2 - P_s^2) = (1{,}000{,}000 - 900{,}600) = 99{,}400$.

DISCUSSION OF TABLES

In this report, the friction drop due to gas flow in the producing string of a gas well is based upon Weymouth's formula [54] for flow of gas through pipe lines. The formula can be expressed as follows:

$$Q = 48{,}960 \left[\frac{(P_1^2 - P_w^2)\, d^{5\,1/3}}{GL}\right]^{1/2} \quad \text{(1)}$$

where Q = rate of flow, cubic feet per 24 hours, at 14.4 pounds per square inch absolute and 60° F., and for average flowing temperature of 80° F.;
P_1 = pressure at the wellhead, plus the pressure drop due to friction, pounds per square inch absolute;
P_w = pressure at the wellhead, pounds per square inch absolute;
d = internal diameter of pipe, inches;
G = specific gravity of gas (air = 1.00); and
L = average length of gas column, feet.

In terms of P_1, the formula becomes:

$$P_1 = \sqrt{P_w^2 + \left[\frac{Q\sqrt{GL}}{48{,}960 d^{8/3}}\right]^2} = \sqrt{P_w^2 + R^2} \quad \text{(2)}$$

where

$$R = \left[\frac{Q\sqrt{GL}}{48{,}960 d^{8/3}}\right] = \sqrt{P_1^2 - P_w^2} \quad \text{(3)}$$

Tables can be prepared from formulas (2) and (3) to facilitate calculation of pressure drops in producing strings due to friction for particular internal diameters of producing strings. For instance, with a given internal diameter of producing string one table could be calculated from formula (3) to show values of R corresponding to different values of GL and Q, and a second table could be determined from formula (2) to show pressure drops due to friction corresponding to different values of R and P_w. However, a set of tables for each size of producing string would be necessary and such a series of tables would be too voluminous for practical use. The series of tables in this report have been simplified by computing one table (table 34) from formula (3) to show values of R corre-

[54] Weymouth, T. R., Problems in Natural-Gas Engineering: Trans. Am. Soc. Mech. Eng., vol. 34, 1912, pp. 185-231.
Johnson, T. W., and Berwald, W. B., Flow of Natural Gas Through High-Pressure Transmission Lines: Rept. of Investigations 2942, Bureau of Mines, 1929, p. 8.
Berwald, W. B., and Johnson, T. W., Factors Influencing Flow of Natural Gas Through High-Pressure Transmission Lines: Rept. of Investigations 3153, Bureau of Mines, 1931, p. 7.

TABLE 37.—*Determination of pressure due to weight of gas column, pounds per square inch*

Values of GLF	Pressure at wellhead plus pressure drop due to friction, P_1, lb. per sq. in. absolute																	
	100	150	200	250	300	350	400	450	500	550	600	650	700	750	800	850	900	950
	Pressure due to weight of gas column, lb. per sq. in.																	
600	2	3	4	5	6	7	8	9	11	12	13	14	15	16	17	18	19	20
700	2	4	5	6	7	9	10	11	12	14	15	16	17	18	20	21	22	23
800	3	4	6	7	8	10	11	13	14	15	17	18	20	21	23	24	25	27
900	3	5	6	8	10	11	13	14	16	17	19	21	22	24	25	27	29	30
1,000	4	5	7	9	11	12	14	16	18	19	21	23	25	26	28	30	32	34
1,100	4	6	8	10	12	14	16	18	19	21	23	25	27	29	31	33	35	37
1,200	4	6	9	11	13	15	17	19	21	23	26	28	30	32	34	36	38	40
1,300	5	7	9	12	14	16	18	21	23	25	28	30	32	35	37	39	42	44
1,400	5	7	10	12	15	17	20	22	25	27	30	32	35	37	40	42	45	47
1,500	5	8	11	13	16	19	21	24	27	29	32	35	37	40	43	45	48	51
1,600	6	9	11	14	17	20	23	26	29	31	34	37	40	43	46	49	51	54
1,700	6	9	12	15	18	21	24	27	30	33	36	40	43	46	49	52	55	58
1,800	6	10	13	16	19	23	26	29	32	35	39	42	45	48	52	55	58	61
1,900	7	10	14	17	20	24	27	31	34	37	41	44	48	51	55	58	61	65
2,000	7	11	14	18	22	25	29	32	36	40	43	47	50	54	57	61	65	68
2,100	8	11	15	19	23	26	30	34	38	41	45	49	53	57	60	64	68	72
2,200	8	12	16	20	24	28	32	36	40	44	48	52	56	59	63	67	71	75
2,300	8	12	17	21	25	29	33	37	42	46	50	54	58	62	66	71	75	79
2,400	9	13	17	22	26	30	35	39	43	48	52	56	61	65	69	74	78	83
,500	9	14	18	23	27	32	36	41	45	50	54	59	63	68	73	77	82	86
2,600	9	14	19	24	28	33	38	42	47	52	57	61	66	71	76	80	85	90
2,700	10	15	20	25	29	34	39	44	49	54	59	64	69	74	79	83	88	93
2,800	10	15	20	26	31	36	41	46	51	56	61	66	71	77	82	87	92	97
2,900	11	16	21	26	32	37	42	48	53	58	64	69	74	79	85	90	95	101
3,000	11	16	22	27	33	38	44	49	55	60	66	71	77	82	88	93	99	104
3,200	12	18	23	29	35	41	47	53	59	65	70	76	82	88	94	100	106	112
3,400	13	19	25	31	38	44	50	56	63	69	75	81	88	94	100	106	113	119
3,600	13	20	27	33	40	47	53	60	67	73	80	86	93	100	106	113	120	126
3,800	14	21	28	35	42	49	56	63	70	78	85	92	99	106	113	120	127	134
4,000	15	22	30	37	45	52	60	67	74	82	89	97	104	112	119	127	134	141

TABLE 37.—*Determination of pressure due to weight of gas column, pounds per square inch*—Continued

Values of GLF	Pressure at wellhead plus pressure drop due to friction, P_1, lb. per sq. in. absolute															
	1,000	1,100	1,200	1,300	1,400	1,500	1,600	1,700	1,800	1,900	2,000	2,100	2,200	2,300	2,400	2,500
	Pressure due to weight of gas column, lb. per sq. in.															
600	21	23	25	27	29	32	34	36	38	40	42	44	46	48	50	53
700	25	27	30	32	34	37	39	42	44	47	49	52	54	57	59	61
800	28	31	34	37	39	42	45	48	51	53	56	59	62	65	68	70
900	32	35	38	41	44	48	51	54	57	60	63	67	70	73	76	79
1,000	35	39	42	46	49	53	56	60	64	67	71	74	78	81	85	88
1,100	39	43	47	51	54	58	62	66	70	74	78	82	86	89	93	97
1,200	43	47	51	55	60	64	68	72	77	81	85	89	94	98	102	106
1,300	46	51	55	60	65	69	74	78	83	87	92	97	102	106	111	115
1,400	50	55	60	65	70	75	80	85	90	95	100	105	110	114	119	124
1,500	53	59	64	69	75	80	85	91	96	102	107	112	118	123	128	134
1,600	57	63	69	74	80	86	91	97	103	108	114	120	126	131	137	143
1,700	61	67	73	79	85	91	97	103	109	115	122	128	134	140	146	152
1,800	64	71	77	84	90	97	103	110	116	122	129	135	142	148	155	161
1,900	68	75	82	89	95	102	109	116	123	130	136	143	150	157	164	170
2,000	72	79	86	93	101	108	115	122	129	137	144	151	158	165	172	180
2,100	75	83	90	98	105	113	121	128	136	143	151	158	166	173	181	188
2,200	79	87	95	103	111	119	127	135	143	151	159	167	175	182	190	198
2,300	83	91	100	108	116	125	133	141	150	158	166	174	183	191	199	208
2,400	87	96	104	113	122	130	139	148	156	165	174	182	191	200	208	217
2,500	91	100	109	118	127	136	145	154	163	172	181	190	199	208	218	227
2,600	94	104	113	123	132	142	151	161	170	179	189	198	208	217	227	236
2,700	98	108	118	128	137	147	157	167	177	187	196	206	216	226	236	246
2,800	102	112	122	133	143	153	163	173	184	194	204	214	224	235	245	255
2,900	106	116	127	138	148	159	169	180	191	201	212	222	233	244	254	265
3,000	110	121	132	143	154	165	176	187	197	208	219	230	241	252	263	274
3,200	117	129	141	153	164	176	188	200	211	223	235	247	258	270	282	294
3,400	125	138	150	163	175	188	200	213	225	238	250	263	275	288	300	313
3,600	133	146	160	173	186	200	213	226	240	253	266	279	293	306	319	333
3,800	141	155	169	183	197	211	226	240	254	268	282	296	310	324	338	352
4,000	149	164	179	194	208	223	238	253	268	283	298	313	328	342	357	372

TABLE 38.—*Squares of pressures, expressed in thousands*

Pressure, lb.	0	1	2	3	4	5	6	7	8	9
10......	0.10	0.12	0.14	0.17	0.20	0.23	0.26	0.29	0.32	0.36
20......	.40	.44	.48	.53	.58	.63	.68	.73	.78	.84
30......	.90	.96	1.02	1.09	1.16	1.23	1.30	1.37	1.44	1.52
40......	1.60	1.68	1.76	1.85	1.94	2.03	2.12	2.21	2.30	2.40
50......	2.50	2.60	2.70	2.81	2.92	3.03	3.14	3.25	3.36	3.48
60......	3.60	3.72	3.84	3.97	4.10	4.23	4.36	4.49	4.62	4.76
70......	4.90	5.04	5.18	5.33	5.48	5.63	5.78	5.93	6.08	6.24
80......	6.40	6.56	6.72	6.89	7.06	7.23	7.40	7.57	7.74	7.92
90......	8.10	8.28	8.46	8.65	8.84	9.03	9.22	9.41	9.60	9.80
100......	10.00	10.20	10.40	10.61	10.82	11.03	11.24	11.45	11.66	11.88
110......	12.10	12.32	12.54	12.77	13.00	13.23	13.46	13.69	13.92	14.16
120......	14.40	14.64	14.88	15.13	15.38	15.63	15.88	16.13	16.38	16.64
130......	16.90	17.16	17.42	17.69	17.96	18.23	18.50	18.77	19.04	19.32
140......	19.60	19.88	20.16	20.45	20.74	21.03	21.32	21.61	21.90	22.20
150......	22.50	22.80	23.10	23.41	23.72	24.03	24.34	24.65	24.96	25.28
160......	25.60	25.92	26.24	26.57	26.90	27.23	27.56	27.89	28.22	28.56
170......	28.90	29.24	29.58	29.93	30.28	30.63	30.98	31.33	31.68	32.04
180......	32.40	32.76	33.12	33.49	33.86	34.23	34.60	34.97	35.34	35.72
190......	36.10	36.48	36.86	37.25	37.64	38.03	38.42	38.81	39.20	39.60
200......	40.00	40.40	40.80	41.21	41.62	42.03	42.44	42.85	43.26	43.68
210......	44.10	44.52	44.94	45.37	45.80	46.23	46.66	47.09	47.52	47.96
220......	48.40	48.84	49.28	49.73	50.18	50.63	51.08	51.53	51.98	52.44
230......	52.90	53.36	53.82	54.29	54.76	55.23	55.70	56.17	56.64	57.12
240......	57.60	58.08	58.56	59.05	59.54	60.03	60.52	61.01	61.50	62.00
250......	62.50	63.00	63.50	64.01	64.52	65.03	65.54	66.05	66.56	67.08
260......	67.60	68.12	68.64	69.17	69.70	70.23	70.76	71.29	71.82	72.36
270......	72.90	73.44	73.98	74.53	75.08	75.63	76.18	76.73	77.28	77.84
280......	78.40	78.96	79.52	80.09	80.66	81.23	81.80	82.37	82.94	83.52
290......	84.10	84.68	85.26	85.85	86.44	87.03	87.62	88.21	88.80	89.40
300......	90.00	90.60	91.20	91.81	92.42	93.03	93.64	94.25	94.86	95.48
310......	96.10	96.72	97.34	97.97	98.60	99.23	99.86	100.49	101.12	101.76
320......	102.40	103.04	103.68	104.33	104.98	105.63	106.28	106.93	107.58	108.24
330......	108.90	109.56	110.22	110.89	111.56	112.23	112.90	113.57	114.24	114.92
340......	115.60	116.28	116.96	117.65	118.34	119.03	119.72	120.41	121.10	121.80
350......	122.50	123.20	123.90	124.61	125.32	126.03	126.74	127.45	128.16	128.88
360......	129.6	130.3	131.0	131.8	132.5	133.2	134.0	134.7	135.4	136.2
370......	136.9	137.6	138.4	139.1	139.9	140.6	141.4	142.1	142.9	143.6
380......	144.4	145.2	145.9	146.7	147.5	148.2	149.0	149.8	150.5	151.3
390......	152.1	152.9	153.7	154.4	155.2	156.0	156.8	157.6	158.4	159.2
400......	160.0	160.8	161.6	162.4	163.2	164.0	164.8	165.6	166.5	167.3
410......	168.1	168.9	169.7	170.6	171.4	172.2	173.1	173.9	174.7	175.6
420......	176.4	177.2	178.1	178.9	179.8	180.6	181.5	182.3	183.2	184.0
430......	184.9	185.8	186.6	187.5	188.4	189.2	190.1	191.0	191.8	192.7
440......	193.6	194.5	195.4	196.2	197.1	198.0	198.9	199.8	200.7	201.6
450......	202.5	203.4	204.3	205.2	206.1	207.0	207.9	208.8	209.8	210.7
460......	211.6	212.5	213.4	214.4	215.3	216.2	217.2	218.1	219.0	220.0
470......	220.9	221.8	222.8	223.7	224.7	225.6	226.6	227.5	228.5	229.4
480......	230.4	231.4	232.3	233.3	234.3	235.2	236.2	237.2	238.1	239.1
490......	240.1	241.1	242.1	243.0	244.0	245.0	246.0	247.0	248.0	249.0
500......	250.0	251.0	252.0	253.0	254.0	255.0	256.0	257.0	258.1	259.1
510......	260.1	261.1	262.1	263.2	264.2	265.2	266.3	267.3	268.3	269.4
520......	270.4	271.4	272.5	273.5	274.6	275.6	276.7	277.7	278.8	279.8
530......	280.9	282.0	283.0	284.1	285.2	286.2	287.3	288.4	289.4	290.5
540......	291.6	292.7	293.8	294.8	295.9	297.0	298.1	299.2	300.3	301.4
550......	302.5	303.6	304.7	305.8	306.9	308.0	309.1	310.2	311.4	312.5
560......	313.6	314.7	315.8	317.0	318.1	319.2	320.4	321.5	322.6	323.8
570......	324.9	326.0	327.2	328.3	329.5	330.6	331.8	332.9	334.1	335.2
580......	336.4	337.6	338.7	339.9	341.1	342.2	343.4	344.6	345.7	346.9
590......	348.1	349.3	350.5	351.6	352.8	354.0	355.2	356.4	357.6	358.8
600......	360.0	361.2	362.4	363.6	364.8	366.0	367.2	368.4	369.7	370.9
610......	372.1	373.3	374.5	375.8	377.0	378.2	379.5	380.7	381.9	383.2
620......	384.4	385.6	386.9	388.1	389.4	390.6	391.9	393.1	394.4	395.6
630......	396.9	398.2	399.4	400.7	402.0	403.2	404.5	405.8	407.0	408.3
640......	409.6	410.9	412.2	413.4	414.7	416.0	417.3	418.6	419.9	421.2
650......	422.5	423.8	425.1	426.4	427.7	429.0	430.3	431.6	433.0	434.3
660......	435.6	436.9	438.2	439.6	440.9	442.2	443.6	444.9	446.2	447.6
670......	448.9	450.2	451.6	452.9	454.3	455.6	457.0	458.3	459.7	461.0
680......	462.4	463.8	465.1	466.5	467.9	469.2	470.6	472.0	473.3	474.7
690......	476.1	477.5	478.9	480.2	481.6	483.0	484.4	485.8	487.2	488.6
700......	490.0	491.4	492.8	494.2	495.6	497.0	498.4	499.8	501.3	502.7
710......	504.1	505.5	506.9	508.4	509.8	511.2	512.7	514.1	515.5	517.0
720......	518.4	519.8	521.3	522.7	524.2	525.6	527.1	528.5	530.0	531.4
730......	532.9	534.4	535.8	537.3	538.8	540.2	541.7	543.2	544.6	546.1
740......	547.6	549.1	550.6	552.0	553.5	555.0	556.5	558.0	559.5	561.0
750......	562.5	564.0	565.5	567.0	568.5	570.0	571.5	573.0	574.6	576.1
760......	577.6	579.1	580.6	582.2	583.7	585.2	586.8	588.3	589.8	591.4
770......	592.9	594.4	596.0	597.5	599.1	600.6	602.2	603.7	605.3	606.8
780......	608.4	610.0	611.5	613.1	614.7	616.2	617.8	619.4	620.9	622.5
790......	624.1	625.7	627.3	628.8	630.4	632.0	633.6	635.2	636.8	638.4
800......	640.0	641.6	643.2	644.8	646.4	648.0	649.6	651.2	652.9	654.5
810......	656.1	657.7	659.3	661.0	662.6	664.2	665.9	667.5	669.1	670.8
820......	672.4	674.0	675.7	677.3	679.0	680.6	682.3	683.9	685.6	687.2
830......	688.9	690.6	692.2	693.9	695.6	697.2	698.9	700.6	702.2	703.9

TABLE 38.—*Squares of pressures, expressed in thousands*—Continued

Pressure, lb.	0	1	2	3	4	5	6	7	8	9
840......	705.6	707.3	709.0	710.6	712.3	714.0	715.7	717.4	719.1	720.8
850......	722.5	724.2	725.9	727.6	729.3	731.0	732.7	734.4	736.2	737.9
860......	739.6	741.3	743.0	744.8	746.5	748.2	750.0	751.7	753.4	755.2
870......	756.9	758.6	760.4	762.1	763.9	765.6	767.4	769.1	770.9	772.6
880......	774.4	776.2	777.9	779.7	781.5	783.2	785.0	786.8	788.5	790.3
890......	792.1	793.9	795.7	797.4	799.2	801.0	802.8	804.6	806.4	808.2
900......	810.0	811.8	813.6	815.4	817.2	819.0	820.8	822.6	824.5	826.3
910......	828.1	829.9	831.7	833.6	835.4	837.2	839.1	840.9	842.7	844.6
920......	846.4	848.2	850.1	851.9	853.8	855.6	857.5	859.3	861.2	863.0
930......	864.9	866.8	868.6	870.5	872.4	874.2	876.1	878.0	879.8	881.7
940......	883.6	885.5	887.4	889.2	891.1	893.0	894.9	896.8	898.7	900.6
950......	902.5	904.4	906.3	908.2	910.1	912.0	913.9	915.8	917.8	919.7
960......	921.6	923.5	925.4	927.4	929.3	931.2	933.2	935.1	937.0	939.0
970......	940.9	942.8	944.8	946.7	948.7	950.6	952.6	954.5	956.5	958.4
980......	960.4	962.4	964.3	966.3	968.3	970.2	972.2	974.2	976.1	978.1
990......	980.1	982.1	984.1	986.0	988.0	990.0	992.0	994.0	996.0	998.0
1,000......	1,000	1,002	1,004	1,006	1,008	1,010	1,012	1,014	1,016	1,018
1,010......	1,020	1,022	1,024	1,026	1,028	1,030	1,032	1,034	1,036	1,038
1,020......	1,040	1,042	1,044	1,047	1,049	1,051	1,053	1,055	1,057	1,059
1,030......	1,061	1,063	1,065	1,067	1,069	1,071	1,073	1,075	1,077	1,080
1,040......	1,082	1,084	1,086	1,088	1,090	1,092	1,094	1,096	1,098	1,100
1,050......	1,103	1,105	1,107	1,109	1,111	1,113	1,115	1,117	1,119	1,121
1,060......	1,124	1,126	1,128	1,130	1,132	1,134	1,136	1,138	1,141	1,143
1,070......	1,145	1,147	1,149	1,151	1,153	1,156	1,158	1,160	1,162	1,164
1,080......	1,166	1,169	1,171	1,173	1,175	1,177	1,179	1,182	1,184	1,186
1,090......	1,188	1,190	1,192	1,195	1,197	1,199	1,201	1,203	1,206	1,208
1,100......	1,210	1,212	1,214	1,217	1,219	1,221	1,223	1,225	1,228	1,230
1,110......	1,232	1,234	1,237	1,239	1,241	1,243	1,245	1,248	1,250	1,252
1,120......	1,254	1,257	1,259	1,261	1,263	1,266	1,268	1,270	1,272	1,275
1,130......	1,277	1,279	1,281	1,284	1,286	1,288	1,290	1,293	1,295	1,297
1,140......	1,300	1,302	1,304	1,306	1,309	1,311	1,313	1,316	1,318	1,320
1,150......	1,323	1,325	1,327	1,329	1,332	1,334	1,336	1,339	1,341	1,343
1,160......	1,346	1,348	1,350	1,353	1,355	1,357	1,360	1,362	1,364	1,367
1,170......	1,369	1,371	1,374	1,376	1,378	1,381	1,383	1,385	1,388	1,390
1,180......	1,392	1,395	1,397	1,399	1,402	1,404	1,407	1,409	1,411	1,414
1,190......	1,416	1,418	1,421	1,423	1,426	1,428	1,430	1,433	1,435	1,438
1,200......	1,440	1,442	1,445	1,447	1,450	1,452	1,454	1,457	1,459	1,462
1,210......	1,464	1,467	1,469	1,471	1,474	1,476	1,479	1,481	1,484	1,486
1,220......	1,488	1,491	1,493	1,496	1,498	1,501	1,503	1,506	1,508	1,510
1,230......	1,513	1,515	1,518	1,520	1,523	1,525	1,528	1,530	1,533	1,535
1,240......	1,538	1,540	1,543	1,545	1,548	1,550	1,553	1,555	1,558	1,560
1,250......	1,563	1,565	1,568	1,570	1,573	1,575	1,578	1,580	1,583	1,585
1,260......	1,588	1,590	1,593	1,595	1,598	1,600	1,603	1,605	1,608	1,610
1,270......	1,613	1,615	1,618	1,621	1,623	1,626	1,628	1,631	1,633	1,636
1,280......	1,638	1,641	1,644	1,646	1,649	1,651	1,654	1,656	1,659	1,662
1,290......	1,664	1,667	1,669	1,672	1,674	1,677	1,680	1,682	1,685	1,687
1,300......	1,690	1,693	1,695	1,698	1,700	1,703	1,706	1,708	1,711	1,713
1,310......	1,716	1,719	1,721	1,724	1,727	1,729	1,732	1,734	1,737	1,740
1,320......	1,742	1,745	1,748	1,750	1,753	1,756	1,758	1,761	1,764	1,766
1,330......	1,769	1,772	1,774	1,777	1,780	1,782	1,785	1,788	1,790	1,793
1,340......	1,796	1,798	1,801	1,804	1,806	1,809	1,812	1,814	1,817	1,820
1,350......	1,823	1,825	1,828	1,831	1,833	1,836	1,839	1,841	1,844	1,847
1,360......	1,850	1,852	1,855	1,858	1,860	1,863	1,866	1,869	1,871	1,874
1,370......	1,877	1,880	1,882	1,885	1,888	1,891	1,893	1,896	1,899	1,902
1,380......	1,904	1,907	1,910	1,913	1,915	1,918	1,921	1,924	1,927	1,929
1,390......	1,932	1,935	1,938	1,940	1,943	1,946	1,949	1,952	1,954	1,957
1,400......	1,960	1,963	1,966	1,968	1,971	1,974	1,977	1,980	1,982	1,985
1,410......	1,988	1,991	1,994	1,997	1,999	2,002	2,005	2,008	2,011	2,014
1,420......	2,016	2,019	2,022	2,025	2,028	2,031	2,033	2,036	2,039	2,042
1,430......	2,045	2,048	2,051	2,053	2,056	2,059	2,062	2,065	2,068	2,071
1,440......	2,074	2,076	2,079	2,082	2,085	2,088	2,091	2,094	2,097	2,100
1,450......	2,103	2,105	2,108	2,111	2,114	2,117	2,120	2,123	2,126	2,129
1,460......	2,132	2,135	2,137	2,140	2,143	2,146	2,149	2,152	2,155	2,158
1,470......	2,161	2,164	2,167	2,170	2,173	2,176	2,179	2,182	2,184	2,187
1,480......	2,190	2,193	2,196	2,199	2,202	2,205	2,208	2,211	2,214	2,217
1,490......	2,220	2,223	2,226	2,229	2,232	2,235	2,238	2,241	2,244	2,247
1,500......	2,250	2,253	2,256	2,259	2,262	2,265	2,268	2,271	2,274	2,277
1,510......	2,280	2,283	2,286	2,289	2,292	2,295	2,298	2,301	2,304	2,307
1,520......	2,310	2,313	2,316	2,320	2.323	2,326	2,329	2,332	2,335	2,338
1,530......	2,341	2,344	2,347	2,350	2,353	2,356	2,359	2,362	2,365	2,369
1,540......	2,372	2,375	2,378	2,381	2,384	2,387	2,390	2,393	2,396	2,399
1,550......	2,403	2,406	2,409	2,412	2,415	2,418	2,421	2,424	2,427	2,430
1,560......	2,434	2,437	2,440	2,443	2,446	2,449	2,452	2,455	2,459	2,462
1,570......	2,465	2,468	2,471	2,474	2,477	2,481	2,484	2,487	2,490	2,493
1,580......	2,496	2,500	2,503	2,506	2,509	2,512	2,515	2,519	2,522	2,525
1,590......	2,528	2,531	2,534	2,538	2,541	2,544	2,547	2,550	2,554	2,557
1,600......	2,560	2,563	2,566	2,570	2,573	2,576	2,579	2,582	2,586	2,589
1,610......	2,592	2,595	2,599	2,602	2,605	2,608	2,611	2,615	2,618	2,621
1,620......	2,624	2,628	2,631	2,634	2,637	2,641	2,644	2,647	2,650	2,654
1,630......	2,657	2,660	2,663	2,667	2,670	2,673	2,676	2,680	2,683	2,686
1,640......	2,690	2,693	2,696	2,699	2,703	2,706	2,709	2,713	2,716	2,719
1,650......	2,723	2,726	2,729	2,732	2,736	2,739	2,742	2,746	2,749	2,752
1,660......	2,756	2,759	2,762	2,766	2,769	2,772	2,776	2,779	2,782	2,786

TABLE 38.—*Squares of pressures, expressed in thousands*—Continued

Pressure, lb.	0	1	2	3	4	5	6	7	8	9
1,670......	2,789	2,792	2,796	2,799	2,802	2,806	2,809	2,812	2,816	2,819
1,680......	2,822	2,826	2,829	2,832	2,836	2,839	2,843	2,846	2,849	2,853
1,690......	2,856	2,859	2,863	2,866	2,870	2,873	2,876	2,880	2,883	2,887
1,700......	2,890	2,893	2,897	2,900	2,904	2,907	2,910	2,914	2,917	2,921
1,710......	2,924	2,928	2,931	2,934	2,938	2,941	2,945	2,948	2,952	2,955
1,720......	2,958	2,962	2,965	2,969	2,972	2,976	2,979	2,983	2,986	2,989
1,730......	2,993	2,996	3,000	3,003	3,007	3,010	3,014	3,017	3,021	3,024
1,740......	3,028	3,031	3,035	3,038	3,042	3,045	3,049	3,052	3,056	3,059
1,750......	3,063	3,066	3,070	3,073	3,077	3,080	3,084	3,087	3,091	3,094
1,760......	3,098	3,101	3,105	3,108	3,112	3,115	3,119	3,122	3,126	3,129
1,770......	3,133	3,136	3,140	3,144	3,147	3,151	3,154	3,158	3,161	3,165
1,780......	3,168	3,172	3,176	3,179	3,183	3,186	3,190	3,193	3,197	3,201
1,790......	3,204	3,208	3,211	3,215	3,218	3,222	3,226	3,229	3,233	3,236
1,800......	3,240	3,244	3,247	3,251	3,254	3,258	3,262	3,265	3,269	3,272
1,810......	3,276	3,280	3,283	3,287	3,291	3,294	3,298	3,301	3,305	3,309
1,820......	3,312	3,316	3,320	3,323	3,327	3,331	3,334	3,338	3,342	3,345
1,830......	3,349	3,353	3,356	3,360	3,364	3,367	3,371	3,375	3,378	3,382
1,840......	3,386	3,389	3,393	3,397	3,400	3,404	3,408	3,411	3,415	3,419
1,850......	3,423	3,426	3,430	3,434	3,437	3,441	3,445	3,448	3,452	3,456
1,860......	3,460	3,463	3,467	3,471	3,474	3,478	3,482	3,486	3,489	3,493
1,870......	3,497	3,501	3,504	3,508	3,512	3,516	3,519	3,523	3,527	3,531
1,880......	3,534	3,538	3,542	3,546	3,549	3,553	3,557	3,561	3,565	3,568
1,890......	3,572	3,576	3,580	3,583	3,587	3,591	3,595	3,599	3,602	3,606
1,900......	3,610	3,614	3,618	3,621	3,625	3,629	3,633	3,637	3,640	3,644
1,910......	3,648	3,652	3,656	3,660	3,663	3,667	3,671	3,675	3,679	3,683
1,920......	3,686	3,690	3,694	3,698	3,702	3,706	3,709	3,713	3,717	3,721
1,930......	3,725	3,729	3,733	3,736	3,740	3,744	3,748	3,752	3,756	3,760
1,940......	3,764	3,767	3,771	3,775	3,779	3,783	3,787	3,791	3,795	3,799
1,950......	3,803	3,806	3,810	3,814	3,818	3,822	3,826	3,830	3,834	3,838
1,960......	3,842	3,846	3,849	3,853	3,857	3,861	3,865	3,869	3,873	3,877
1,970......	3,881	3,885	3,889	3,893	3,897	3,901	3,905	3,909	3,912	3,916
1,980......	3,920	3,924	3,928	3,932	3,936	3,940	3,944	3,948	3,952	3,956
1,990......	3,960	3,964	3,968	3,972	3,976	3,980	3,984	3,988	3,992	3,996
2,000......	4,000	4,004	4,008	4,012	4,016	4,020	4,024	4,028	4,032	4,036
2,010......	4,040	4,044	4,048	4,052	4,056	4,060	4,064	4,068	4,072	4,076
2,020......	4,080	4,084	4,088	4,093	4,097	4,101	4,105	4,109	4,113	4,117
2,030......	4,121	4,125	4,129	4,133	4,137	4,141	4,145	4,149	4,153	4,158
2,040......	4,162	4,166	4,170	4,174	4,178	4,182	4,186	4,190	4,194	4,198
2,050......	4,203	4,207	4,211	4,215	4,219	4,223	4,227	4,231	4,235	4,239
2,060......	4,244	4,248	4,252	4,256	4,260	4,264	4,268	4,272	4,277	4,281
2,070......	4,285	4,289	4,293	4,297	4,301	4,306	4,310	4,314	4,318	4,322
2,080......	4,326	4,331	4,335	4,339	4,343	4,347	4,351	4,356	4,360	4,364
2,090......	4,368	4,372	4,376	4,381	4,385	4,389	4,393	4,397	4,402	4,406
2,100......	4,410	4,414	4,418	4,423	4,427	4,431	4,435	4,439	4,444	4,448
2,110......	4,452	4,456	4,461	4,465	4,469	4,473	4,477	4,482	4,486	4,490
2,120......	4,494	4,499	4,503	4,507	4,511	4,516	4,520	4,524	4,528	4,533
2,130......	4,537	4,541	4,545	4,550	4,554	4,558	4,562	4,567	4,571	4,575
2,140......	4,580	4,584	4,588	4,592	4,597	4,601	4,605	4,610	4,614	4,618
2,150......	4,623	4,627	4,631	4,635	4,640	4,644	4,648	4,653	4,657	4,661
2,160......	4,666	4,670	4,674	4,679	4,683	4,687	4,692	4,696	4,700	4,705
2,170......	4,709	4,713	4,718	4,722	4,726	4,731	4,735	4,739	4,744	4,748
2,180......	4,752	4,757	4,761	4,765	4,770	4,774	4,779	4,783	4,787	4,792
2,190......	4,796	4,800	4,805	4,809	4,814	4,818	4,822	4,827	4,831	4,836
2,200......	4,840	4,844	4,849	4,853	4,858	4,862	4,866	4,871	4,875	4,880
2,210......	4,884	4,889	4,893	4,897	4,902	4,906	4,911	4,915	4,920	4,924
2,220......	4,928	4,933	4,937	4,942	4,946	4,951	4,955	4,960	4,964	4,968
2,230......	4,973	4,977	4,982	4,986	4,991	4,995	5,000	5,004	5,009	5,013
2,240......	5,018	5,022	5,027	5,031	5,036	5,040	5,045	5,049	5,054	5,058
2,250......	5,063	5,067	5,072	5,076	5,081	5,085	5,090	5,094	5,099	5,103
2,260......	5,108	5,112	5,117	5,121	5,126	5,130	5,135	5,139	5,144	5,148
2,270......	5,153	5,157	5,162	5,167	5,171	5,176	5,180	5,185	5,189	5,194
2,280......	5,198	5,203	5,208	5,212	5,217	5,221	5,226	5,230	5,235	5,240
2,290......	5,244	5,249	5,253	5,258	5,262	5,267	5,272	5,276	5,281	5,285
2,300......	5,290	5,295	5,299	5,304	5,308	5,313	5,318	5,322	5,327	5,331
2,310......	5,336	5,341	5,345	5,350	5,355	5,359	5,364	5,368	5,373	5,378
2,320......	5,382	5,387	5,392	5,396	5,401	5,406	5,410	5,415	5,420	5,424
2,330......	5,429	5,434	5,438	5,443	5,448	5,452	5,457	5,462	5,466	5,471
2,340......	5,476	5,480	5,485	5,490	5,494	5,499	5,504	5,508	5,513	5,518
2,350......	5,523	5,527	5,532	5,537	5,541	5,546	5,551	5,555	5,560	5,565
2,360......	5,570	5,574	5,579	5,584	5,588	5,593	5,598	5,603	5,607	5,612
2,370......	5,617	5,622	5,626	5,631	5,636	5,641	5,645	5,650	5,655	5,660
2,380......	5,664	5,669	5,674	5,679	5,683	5,688	5,693	5,698	5,703	5,707
2,390......	5,712	5,717	5,722	5,726	5,731	5,736	5,741	5,746	5,750	5,755
2,400......	5,760	5,765	5,770	5,774	5,779	5,784	5,789	5,794	5,798	5,803
2,410......	5,808	5,813	5,818	5,823	5,827	5,832	5,837	5,842	5,847	5,852
2,420......	5,856	5,861	5,866	5,871	5,876	5,881	5,885	5,890	5,895	5,900
2,430......	5,905	5,910	5,915	5,919	5,924	5,929	5,934	5,939	5,944	5,949
2,440......	5,954	5,958	5,963	5,968	5,973	5,978	5,983	5,988	5,993	5,998
2,450......	6,003	6,007	6,012	6,017	6,022	6,027	6,032	6,037	6,042	6,047
2,460......	6,052	6,057	6,061	6,066	6,071	6,076	6,081	6,086	6,091	6,096
2,470......	6,101	6,106	6,111	6,116	6,121	6,126	6,131	6,136	6,140	6,145
2,480......	6,150	6,155	6,160	6,165	6,170	6,175	6,180	6,185	6,190	6,195
2,490......	6,200	6,205	6,210	6,215	6,220	6,225	6,230	6,235	6,240	6,245
2,500......	6,250	..	..	..	..	..	..	..	..	..

sponding to different values of Q and GL for 1-inch tubing and a second table (table 35) from formula (2) to show pressure drops in the producing string due to friction corresponding to different values of R and P_w, and finally preparing a conversion table (table 33) to show the " equivalent GL values " of producing strings of different internal diameters.

The " equivalent GL values " for the various diameters of producing strings shown in table 33 are based on the formula,

$$GL \text{ for 1-inch tubing} = (GL)_d \left[\frac{1.049}{d}\right]^{5\,1/3} \quad \ldots\ldots\ldots (4)$$

where $(GL)_d = GL$ of actual producing string in well,
1.049 = internal diameter of 1-inch tubing,
and d = internal diameter of actual producing string in well.

Formula (4) is derived from formula (1) and shows the factor $\left[\frac{1.049}{d}\right]^{5\,1/3}$ by which the GL values of the actual producing string in the well are multiplied to give the " equivalent GL." The " equivalent GL," then, is the GL value which will allow a flow through 1-inch tubing equal to that through the producing string with its given GL value and may be considered as the GL for 1-inch tubing equivalent to the actual GL of the producing string. Therefore the equivalent GL may be used in the tables based on calculations of pressure drops in 1-inch tubing.

The equivalent GL values in table 33 are based on weights of the indicated sizes of pipe having the internal diameters listed. Tables showing equivalent GL values for other weights of these sizes or the various weights of other sizes of pipe can be prepared from calculations based on equation (4).

Values of R corresponding to different equivalent GL values and delivery rates are shown in table 34, which was computed from formula (3), using 1.049, the internal diameter of 1-inch tubing for d. In formula (3) R is directly proportional to Q; therefore values of R corresponding to delivery rates greater than are listed in table 34 can be obtained by multiplying the value of R in the table by the ratio of delivery rates. For example, assume that it is desired to ascertain the value of R corresponding to a delivery rate of 2,000,000 cubic feet of gas per 24 hours and an equivalent GL of 0.10. In table 34 the value of R corresponding to a delivery rate of 200,000 cubic feet of gas per 24 hours and an equivalent GL of 0.10 is 1.14. The value of R corresponding to a delivery rate of 2,000,000 cubic feet per 24 hours is, therefore,

$$\frac{2{,}000{,}000}{200{,}000} \times 1.14 = 10 \times 1.14 = 11.4.$$

Pressure drops due to friction in the producing strings corresponding to different values of R and wellhead pressures are shown in table 35, which is based on formula (2).

Tables 36 and 37 facilitate calculations of pressures due to weights of columns of moving or stationary gas. The derivation of the formulas used for calculating the values shown in the tables are as follows:

First consider the pressure due to the weight of a static column of gas at a temperature of 80° F. At any pressure, p, the pressure due to the weight of an infinitesimal gas volume is

$$dp = dL\rho \qquad (5)$$

where dL = small vertical length (height) considered, feet;
ρ = density of gas at pressure p, pounds per cubic foot; and
dp = pressure due to weight of gas in the length dL, pounds per square foot.

From the laws of Boyle and Charles,

$$pV = WBT \qquad (6)$$

p = pressure, pounds per square foot;
B is a constant which for air = 53.34, and for gas of gravity $G = \frac{53.34}{G}$;
T = absolute temperature, °F. (459.6 + 80 = 539.6);
V = volume, cubic feet;
W = weight, pounds.

Therefore, for gas of gravity G,

$$pdV = dW\left(\frac{53.34}{G}\right)(539.6) = \frac{28{,}782}{G}\,dW \qquad (7)$$

Also, since density is weight per unit volume,

$$\rho = dW/dV \qquad (8)$$

From (5) and (8),

$$dp = dL\,dW/dV \qquad (9)$$

From (7),

$$dW/dV = \frac{pG}{28{,}782} \qquad (10)$$

Therefore, from (9) and (10),

$$dp = dL\left(\frac{pG}{28{,}782}\right) \qquad (11)$$

or

$$dL = \frac{28{,}782}{G}\,\frac{dp}{p}$$

The ratio $\frac{dp}{p}$, with p in pounds per square foot, is the same as the ratio $\frac{dP}{P}$ with P in pounds per square inch.

By integration, since for a static column of gas $P_1 = P_c$,

$$\int_{L_2}^{L_1} dL = \frac{28{,}782}{G}\int_{P_1}^{P_s} dP/P,$$

or

$$L_1 - L_2 = L = \frac{28{,}782}{G}\left(\log_e P_s - \log_e P_1\right),$$

from which

$$L = \frac{28{,}782}{G}\log_e \frac{P_s}{P_1} \qquad (12)$$

or

$$\log_e P_s/P_1 = 0.0000347GL = 0.0000347GL \log_e e.$$

Therefore

$$P_s/P_1 = e^{0.0000347GL},$$

or

$$P_s = P_1 e^{0.0000347GL} \qquad (13)$$

Equation (13) also can be written,

$$P_s - P_1 = P_1\left(e^{0.0000347GL} - 1\right) \qquad (14)$$

where $P_s - P_1$ = pressure due to weight of a static gas column, pounds per square inch;
P_1 = pressure at wellhead plus pressure drop due to friction, the pressure drop being zero in this case;
L = average length of gas column, feet;
G = specific gravity of gas (air=1.00);
and e = Napierian logarithm base = 2.71828.

With a given pressure, P_1, the mean pressure of a moving column of gas is less than that of a static column in the same well; therefore, the mean density and the pressure due to the weight of the moving column of gas also are less than in the static column. A correction factor, F, in equation (14) makes it possible to use the equation for computing the pressure due to the weight of a moving column of gas. Thus, for a moving column,

$$P_s - P_1 = P_1(e^{0.0000347GLF} - 1) \quad \text{................} (15)$$

Variations in the value of F can be considered most conveniently for purposes of calculation by studying corresponding changes in the ratio P_w/P_1, where P_w is the pressure at the wellhead and P_1 the pressure at the wellhead plus the pressure drop due to friction. The mean pressure between P_1 and P_w for any depth of well, L, as computed from formula (1) is,[55]

$$P_M = 2/3\left(P_1 + P_w - \frac{P_1 + P_w}{P_1 P_w}\right) \quad \text{................} (16)$$

where P_M = mean pressure between P_1 and P_w for length L. Strictly, P_M is applicable only for horizontal flow but can be used for approximate purposes to determine the effect of gas flow on the pressure due to the weight of a column of gas.

The ratio $\frac{P_M}{P_1}$ gives the approximate correction factor F used in formula (15). Dividing both sides of formula (16) by P_1 gives

$$F = \frac{P_M}{P_1} = 2/3\left(1 + P_w/P_1 - \frac{P_w/P_1}{1 + P_w/P_1}\right) \quad \text{...........} (17)$$

Values of correction factor F corresponding to different pressure ratios, P_w/P_1, are shown in table 36, and pressures due to weights of gas columns corresponding to different values of GLF and wellhead pressures are shown in table 37.

CALCULATIONS OF PRESSURES AT THE SAND IN GAS WELLS FROM FORMULAS

The pressure drop due to friction in the producing string and the pressure due to the weight of the column of gas can be calculated from formulas.

FRICTION DROP IN PRODUCING STRING

Reference has been made to the computation of the pressure drop in the producing string by the use of the Weymouth pipe-line flow formula. The derivation of the Weymouth formula[56] involves the

[55] Weymouth, T. R., Problems in Natural-Gas Engineering: Trans. Am. Soc. Mech. Eng., vol. 34, 1912, p. 203.
Rawlins, E. L., and Wosk, L. D., Leakage from High-Pressure Natural-Gas Transmission Lines: Bull. 265, Bureau of Mines, 1928, pp. 41-42.
[56] Johnson, T. W., and Berwald, W. B., Flow of Natural Gas Through High-Pressure Transmission Lines: Monograph 6, Bureau of Mines, 1935, 120 pp.

assumptions of horizontal and isothermal flow, that the gas obeys Boyle's law, and that in the derivation one term whose importance depends upon the ratio of pipe diameter to length of pipe can be neglected. It is hoped that with further study practicable formulas for vertical flow of gas, taking account of deviation from Boyle's law, departure from isothermal conditions, and other factors that influence the flow of gas through producing strings, can be developed and used for more precise determinations of pressure in gas wells. For this report, however, the following practical procedure has been developed for calculating pressure at the sand from pressure observations made at the wellhead on flowing wells.

The pressure drop in the producing string due to friction first is computed from Weymouth's formula, based upon an average temperature of 80° F. This calculation can be modified to satisfy any average temperature for a particular well. The pressure due to the weight of the gas column next is computed, based upon an average temperature condition, and where desirable the effect of deviation of the gas from Boyle's law also is considered. The sum of these two pressures then is taken as the difference between the bottom-hole and wellhead pressures. The calculated pressure due to the weight of the column of gas takes into account in an approximate way the work of lifting the fluid, which is one of the most important factors to be considered in vertical-flow computations. Under the conditions of normal operation of gas wells equipped with only one producing string the pressure drop in the producing string due to friction is small, since the producing string usually is of large diameter and the velocity of the gas comparatively low. Since back-pressure tests are conducted under the normal operating conditions of the wells this procedure has proved satisfactory for all practical purposes in gaging gas-well deliveries. Measurements of bottom-hole pressures in gas wells that have been made with bottom-hole pressure gages were in close agreement with the pressures computed from observations at the wellhead.

Weymouth's formula for flow of gas through horizontal pipes is:

$$Q_{14.65}=15{,}385\left[\frac{(P_1^2-P_2^2)\,d^{5\ 1/3}}{GTL_m}\right]^{1/2},$$

where $Q_{14.65}$=the quantity of gas, based on pressure of 14.65 pounds per square inch and 60° F., cubic feet per 24 hours;
L_m=length of line, miles;
T=flowing temperature, °F. absolute;
G=specific gravity of gas (air=1.00);
d=internal pipe diameter, inches;
P_2=discharge pressure, pounds per square inch absolute;
P_1=inlet pressure, pounds per square inch absolute.

This formula becomes

$$Q=48{,}960\left[\frac{(P_1^2-P_w^2)\,d^{5\ 1/3}}{GL}\right]^{1/2},$$

where Q=the quantity at 14.4 pounds per square inch and 60° F., and for a flowing temperature of 80° F., cubic feet per 24 hours;
L=length, feet;
P_w=pressure at wellhead, pounds per square inch absolute;
P_1=pressure at wellhead plus the pressure drop due to friction, pounds per square inch absolute.

This formula then can be written,

$$P_1=\sqrt{P_w{}^2+\left(\frac{Q\sqrt{GL}}{48{,}960\ d^{8/3}}\right)^2},$$

$$\text{or } P_1=\sqrt{P_w{}^2+R^2}, \text{ where } R=\frac{Q\sqrt{GL}}{48{,}960\ d^{8/3}}=\sqrt{P_1{}^2-P_w{}^2}.$$

Then for any particular size of pipe,

$$R=\frac{Q\sqrt{GL}}{K}, \text{ where } K=48{,}960\ d^{8/3}.$$

Values of K for producing strings of several different internal diameters are shown in table 39.

TABLE 39.—*Values of K for producing strings of different diameters*

Size of pipe, inches		Weight per foot,[1] pounds	Internal diameter, inches	K
Tubing	Casing			
1	..	1.69	1.049	55,622
1¼	..	2.30	1.380	115,571
1½	..	2.75	1.610	174,333
2	..	4.00	2.041	328,150
2½	..	5.90	2.469	545,207
3	..	7.69	3.068	973,043
3½	..	9.26	3.548	1,433,674
4	..	10.98	4.026	2,008,341
6	..	19.37	6.065	5,989,603
..	5³⁄₁₆	9.00	5.192	3,957,224
..	6¼	12.00	6.287	6,591,939
..	6⅝	13.00	6.652	7,662,485
..	8¼	17.50	8.249	13,601,363

[1]With threads and couplings.

If the rate of flow Q and the absolute pressure P_w at the wellhead are known, P_1, the absolute pressure at the wellhead plus the pressure drop due to friction, is calculated in the following manner.

(1) Determine the value of K from table 39.
(2) Substitute the value of K in the formula

$$R=\frac{Q\sqrt{GL}}{K}$$

and solve for R.
(3) Substitute values of R and P_w for the symbols in the formula

$$P_1=\sqrt{P_w{}^2+R^2}$$

and solve for P_1.

WEIGHT OF MOVING COLUMN OF GAS

In a moving column of gas the ratio P_w/P_1 has a value less than 1 and depends upon the rate of flow. In other words, with a given value of P_1, when the column of gas in a well is moving its mean pressure, and therefore its mean density and the pressure due to its weight, are less than when the column is static. The weight of a moving column of gas is determined from the formula,

$$P_s=P_1(e^{0.0000347GLF}),$$

where F=a factor which takes into consideration the density change and is calculated from the formula,

$$F=2/3\left(1+\frac{P_w}{P_1}-\frac{P_w/P_1}{1+P_w/P_1}\right)$$

SAMPLE CALCULATIONS

The following example illustrates the method of computing the pressures at the sand from wellhead observations of volume and pressure.

Assumptions:

L=depth of well=2,000 feet.
G=specific gravity of gas=0.60 (air=1.00).
d=internal diameter of flow string=3.068 inches.
Q=rate of flow=10,000,000 cubic feet of gas per 24 hours.
P_w=pressure at the wellhead=700 pounds per square inch absolute.

Solution:

(1) Determine pressure drop due to friction in the producing string. From table 39, K=973,043.

Substituting the value of K in the formula $R=\frac{Q\sqrt{GL}}{K}$ gives

$$R=\frac{10{,}000{,}000\sqrt{0.6\times 2{,}000}}{973{,}043}=356.$$

Substituting values of P_w and R in the formula $P_1=\sqrt{P_w{}^2+R^2}$ gives $P_1=\sqrt{(700)^2+(356)^2}=785.3$ pounds per square inch absolute.

(2) Determine the pressure due to the weight of the column of gas.

$$P_w/P_1=\frac{700}{785.3}=0.8915.$$

Substituting 0.8915 for P_w/P_1 in the equation

$$F=2/3\left(1+P_w/P_1-\frac{P_w/P_1}{1+P_w/P_1}\right)\text{gives}$$
$$F=2/3\left(1+0.8915-\frac{0.8915}{1+0.8915}\right)=0.947,$$

which, when substituted in the formula $P_s=P_1(e^{0.0000347GLF})$ gives the value of P_s, the pressure at the face of the sand in the well.

$$P_s=(785.3)\,(2.71828)^{(0.0000347)\,(0.6)\,(2000)\,(0.947)}$$
$$=(785.3)\,(2.71828)^{0.03943}$$
$$=816.9 \text{ pounds per square inch absolute.}$$

APPENDIX 6. EFFECT OF CHANGES IN TEMPERATURE AND THE DEVIATION OF GASES FROM BOYLE'S LAW ON THE CALCULATED PRESSURE DUE TO THE WEIGHT OF A COLUMN OF GAS

In most gas wells the pressures and depths are not great enough to cause appreciable errors in calculating pressures at the sand due to the weight of the columns of gas based on the assumption that the gas conforms with Boyle's law. However, pressures and depths to the producing sands in some localities, such as the Oklahoma City field,[57] are so great that deviation of gas from Boyle's law should be considered. Accordingly, the effect of pressure and depth has been studied and will be discussed from a mathematical standpoint. Such an interpretation, of course, does not consider, in definite values, effects of the presence of liquids and solids in the wells.

[57] Hill, H. B., and Rawlins, E. L., Estimate of the Gas Reserves of the Oklahoma City Oil Field, Oklahoma County, Okla.: Rept. of Investigations 3217, Bureau of Mines, 1933, 54 pp.

PRESSURE DUE TO WEIGHT OF STATIC COLUMN OF GAS

The formula for computing the pressure due to the weight of a static column of gas without considering the deviation of gases from Boyle's law is,[58]

$$P_s - P_1 = P_1(e^{0.0000347GL} - 1),$$

where P_s = pressure at bottom of hole, pounds per square inch absolute (under shut-in conditions, $P_f = P_s$);
P_1 = pressure at wellhead plus pressure drop due to friction, pounds per square inch (pressure drop is zero in this case);
$P_s - P_1$ = pressure due to weight of gas column, pounds per square inch;
G = specific gravity of gas (air = 1.00);
L = average length of gas column, feet; and
e = Napierian logarithm base = 2.71828.

The formula is based on an average temperature of the column of gas of 80° F.

Effects of deviation of gases from Boyle's law and the temperature of the gas may be included in the formula as follows:

At some point in the flow string (considering an infinitesimal volume of gas, dV, of vertical length dL) the pressure due to the weight of the infinitesimal volume of gas is

$$dp = dL\,\rho \qquad (1)$$

where dL = vertical length considered, feet;
ρ = density of gas, pounds per cubic foot; and
dp = pressure due to weight of gas in the length dL, pounds per square foot.

By definition, density ρ is the weight divided by the volume, or

$$\rho = \frac{dW}{dV} \qquad (2)$$

From (1)

$$\rho = \frac{dp}{dL} \qquad (3)$$

Therefore, since (2) and (3) are equal,

$$\frac{dp}{dL} = \frac{dW}{dV}\text{, or}$$

$$dp = dL\left(\frac{dW}{dV}\right) \qquad (4)$$

The equation of state for an ideal gas is

$$pV = WBT \qquad (5)$$

where p = pressure, pounds per square foot;
V = volume, cubic feet;
W = weight, pounds;
B = gas constant; and
T = absolute temperature, °F.

The value of B for air is 53.34 based on the volume of 12.39 cubic feet occupied by 1 pound of air at an atmospheric pressure of 14.7 pounds per square inch and a temperature of 32° F. The equation applies to an ideal gas throughout all ranges of pressures and volumes. However, natural gas is not an ideal gas and therefore deviates from Boyle's law.

[58] See equation (14), appendix 5.

The value of B in equation (5) for any gas other than air is $53.34/G$, where G is the specific gravity based on air$=1.00$.

If the gas deviates from Boyle's law the equation may be written as follows and the value of B for air (53.34) may be used in the derivation,

$$pV=W\left[\frac{53.34}{G\left(1+\frac{N}{100}\right)}\right]T, \text{ or}$$

$$pV\left(1+\frac{N}{100}\right)=\frac{53.34}{G}\,WT \qquad (6)$$

where N=percent deviation from Boyle's law at pressure p.

The percent deviation of gas from Boyle's law plotted against pressure on rectangular coordinate paper does not give a straight line over all ranges of pressure; but the relationship established by a straight line drawn through the origin and through a general average of a series of pressure-deviation points usually is accurate enough for computing the weight of a column of gas in a well.

Therefore equation (6) is written,

$$pV(1+Pb)=\frac{53.34}{G}\,WT \qquad (7)$$

where b is the deviation of the gas from Boyle's law, expressed decimally, per pound per square inch of pressure, obtained from

$$b=\frac{N}{(P)(100)} \qquad (8)$$

where P is the pressure, pounds per square inch absolute.

Rewriting equation (7) to indicate the small volume dV of gas occupied by the weight dW at a pressure, p, in pounds per square foot absolute equivalent to P in pounds per square inch absolute,

$$(p)(dV)(1+Pb)=dW\left(\frac{53.34}{G}\right)T \qquad (9)$$

Solving,

$$\frac{dW}{dV}=\frac{p(1+Pb)G}{53.34T} \qquad (10)$$

Substituting this value of $\left(\frac{dW}{dV}\right)$ from equation (10) in equation (4),

$$dp=dL\,\frac{p(1+Pb)G}{53.34T} \qquad (11)$$

from which

$$dL=\left[\frac{53.34T}{G}\right]\left[\frac{dp}{p}\right]\left[\frac{1}{1+Pb}\right],$$

or, since the ratio $\frac{dp}{p}$ with p expressed in pounds per square foot is the same as the ratio $\frac{P}{dP}$ with P expressed in pounds per square inch

$$dL=\left[\frac{53.34T}{G}\right]\left[\frac{dP}{P(1+Pb)}\right] \qquad (12)$$

Equation (12) is applicable between limits from L_1 to L_2 and from

P_s to P_1, where $L_1 - L_2 = L$ = average length of the gas column in the well and $P_s - P_1$ = pressure due to the weight of the column of gas. Therefore, by assigning limits and putting equation (12) into form for integration,

$$\int_{L_2}^{L_1} dL = \frac{53.34T}{G}\int_{P_1}^{P_s} \frac{dP}{P(1+Pb)} \quad \ldots\ldots\ldots\ldots\ldots (13)$$

from which

$$L = \left[\frac{53.34T}{G}\right]\left[\log_e\left(\frac{P_s}{P_1}\right)\left(\frac{1+P_1b}{1+P_sb}\right)\right] \ldots\ldots\ldots\ldots (14)$$

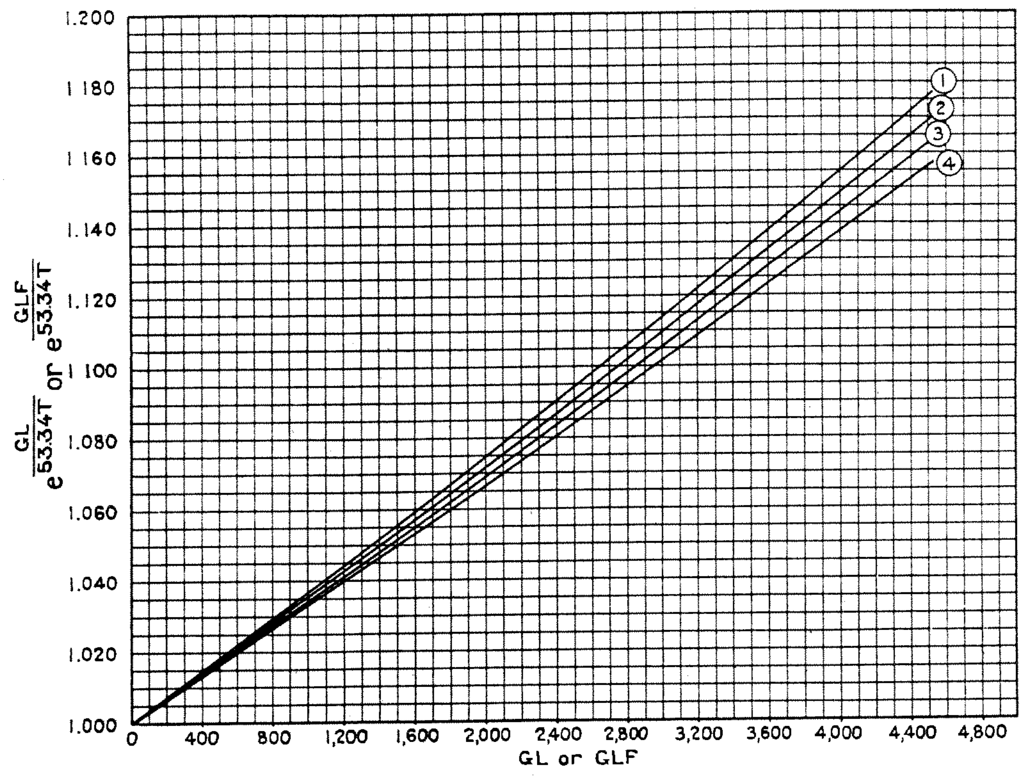


FIGURE 49.—Relationship between $e^{\frac{GL}{53.34T}}$ and GL for different average temperatures in determining effect of deviation of gas from Boyle's law on pressure due to weight of column of gas

Equation (14) then becomes

$$\left[\log_e\left(\frac{P_s}{P_1}\right)\left(\frac{1+P_1b}{1+P_sb}\right)\right] = \frac{GL}{53.34T}\log_e e \ldots\ldots\ldots\ldots (15)$$

or

$$\left(\frac{P_s}{P_1}\right)\left(\frac{1+P_1b}{1+P_sb}\right) = e^{\frac{GL}{53.34T}} \ldots\ldots\ldots\ldots\ldots\ldots (16)$$

from which

$$\left[\frac{P_s}{1+P_sb}\right] = \left[\frac{P_1}{1+P_1b}\right]\left[e^{\frac{GL}{53.34T}}\right] \ldots\ldots\ldots\ldots\ldots (17)$$

where P_s = pressure at the bottom of hole, pounds per square inch absolute;
P_1 = pressure at wellhead plus pressure drop due to friction, pounds per square inch absolute;
b = deviation coefficient, deviation per pound per square inch of pressure, expressed as a decimal;
G = specific gravity of gas (air = 1.00);
L = depth of well, feet; and
T = average temperature of gas column, °F. absolute.

Because formula (17) is somewhat cumbersome to use in routine work charts have been prepared to facilitate the calculations. Similar charts can be prepared for any particular set of conditions.

Values of $e^{\frac{GL}{53.34T}}$ corresponding to values of GL for different average temperatures in the flow string of 60, 80, 100, and 120° F. are shown in figure 49. T is considered to be the average temperature between the bottom of the well and the surface of the ground,

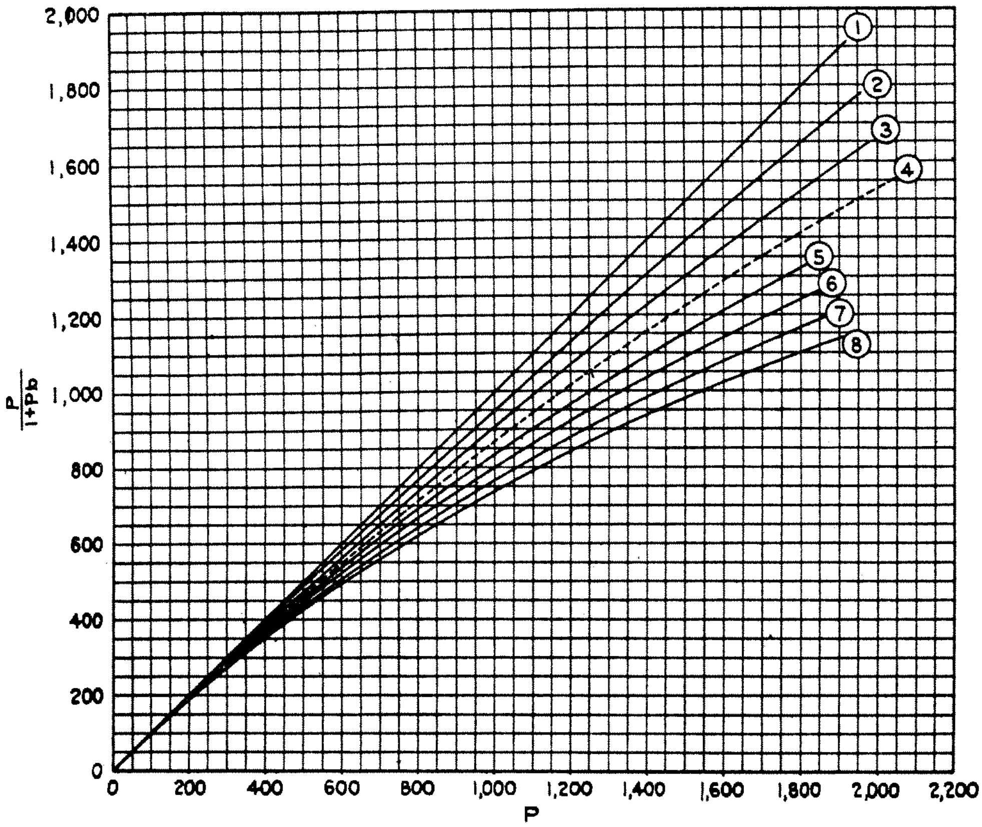


FIGURE 50.—Values of $\frac{P}{1 + Pb}$ corresponding to values of P for different deviation coefficients in determining effect of deviation of gas from Boyle's law on pressure due to weight of gas column

which although not strictly correct is accurate enough for most practical cases.

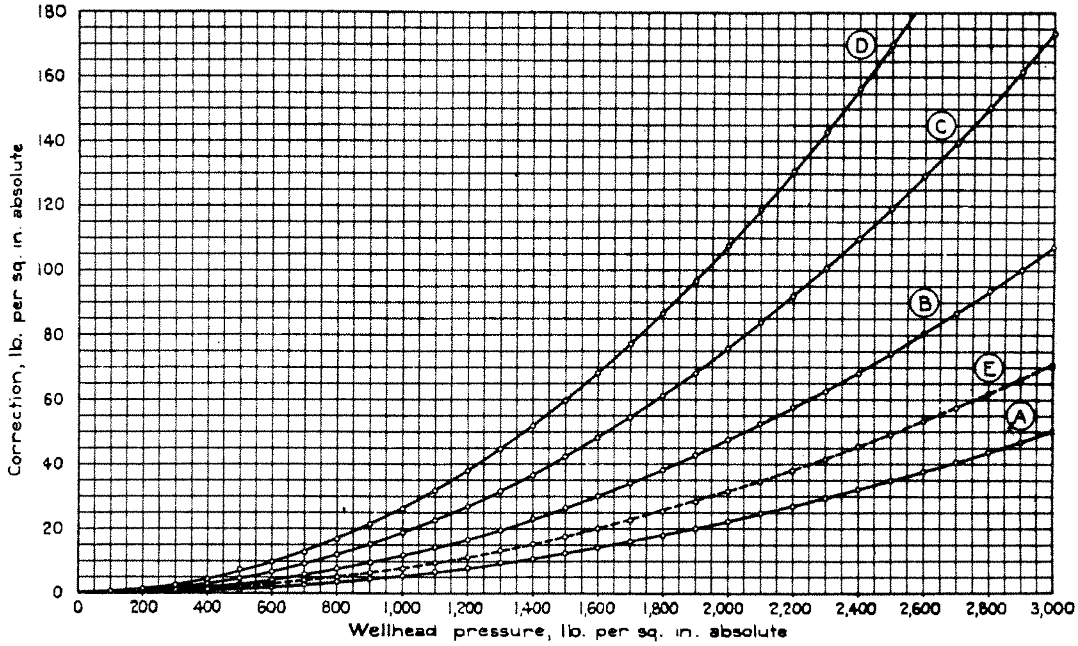
Values of $\frac{P}{1+Pb}$ corresponding to values of P for different values of the deviation coefficient b are shown in figure 50, which can be used to determine the value of $\left(\frac{P_1}{1+P_1b}\right)$ corresponding to a known P_1 and the value of P_s from a determined value of $\left(\frac{P_s}{1+P_sb}\right)$.

The pressure due to the weight of a column of gas can be determined by using figures 49 and 50. Assume, for example, that the following data were obtained on a gas well.

P_1, pressure at wellhead plus pressure drop due to friction=1,000 pounds per square inch absolute;
GL, specific gravity times depth=2,500;
T, average temperature of gas column=80° F.;
b, or deviation coefficient=0.0001 per pound per square inch.

From figure 49 the values of $e^{\frac{GL}{53.34T}}$ corresponding to a GL of 2,500 and a temperature of 80° F.=1.0907.

From figure 50 the value of $\left(\frac{P_1}{1+P_1b}\right)$ corresponding to a P_1 of



Designation	GL	Deviation coefficient, b
A	1,000	0.00015
B	2,000	.00015
C	3,000	.00015
D	4,000	.00015
E	2,000	.00010

FIGURE 51.—Additional pressure due to weight of gas column by considering effect of deviation of gas from Boyle's law

1,000 pounds per square inch and a deviation coefficient of 0.0001 =910.

The product, $910\times1.0907=992.5=\frac{P_s}{1+P_sb}$.

From figure 50 the value of P_s corresponding to a $\left[\frac{P_s}{1+P_sb}\right]$ of 992.5 is 1,101pounds per square inch.

Therefore, the pressure due to the weight of the column of gas is $P_s-P_1=1{,}101-1{,}000$ or 101 pounds per square inch.

The curves in figure 51 illustrate the effect of the deviation of gases from Boyle's law on calculations of pressures due to the weights of columns of gas corresponding to different pressures and well depths. Curves *A*, *B*, *C*, and *D* illustrate the additional pressure due to the weight of a column of gas caused by deviation of the gas from Boyle's law for a deviation factor of 0.00015 and GL values of 1,000, 2,000, 3,000, and 4,000, respectively. The total pressure due to the weight of a column of gas can be computed by adding the pressures obtained from the curves in figure 51 to the pressure obtained when deviation from Boyle's law is not considered.[59] Curve E represents the additional pressure due to the weight of a column of gas caused by deviation of gas from Boyle's law for a deviation coefficient of 0.0001 and a GL value of 2,000. Comparison of curves B and E shows that differences between the deviations of different gases from Boyle's law must be considered if the additional pressure due to the weight of a column of gas caused by deviation from Boyle's law is to be computed. For example, the additional pressure from curve E corresponding to a wellhead pressure of 2,500 pounds per square inch absolute is approximately 49 pounds per square inch, to be compared with 74 pounds per square inch from curve B.

As shown in figure 51 the wellhead pressure and the value of GL are appreciable factors in determining the pressure due to the weight of a column of gas if deviation from Boyle's law is considered. Corrections for deviation are appreciable when pressures and values of GL are high and are negligible at low pressures and low values of GL. Furthermore, under the high pressures found in many deep wells the gas composition depends upon the laws of coexisting phases of mixtures; in other words, at extremely high pressure the gas may consist largely of methane and ethane and nearly all of the heavier hydrocarbons may be in liquid form. As the pressure is lowered such heavier hydrocarbons may vaporize and change the composition of the gas and its deviation coefficient. These factors should be considered in determining deviation coefficients for purposes of calculating the additional pressure due to the weight of a column of gas caused by deviation of the gas from Boyle's law.

PRESSURE DUE TO WEIGHT OF MOVING COLUMN OF GAS

The pressure due to the weight of a moving column of gas, disregarding the deviation of the gas from Boyle's law, is calculated from the formula [60]

$$P_s - P_1 = P_1 (e^{0.0000347GLF} - 1),$$

where P_s = pressure at sand face in well bore, pounds per square inch absolute;
P_1 = pressure at wellhead plus friction drop in producing string, pounds per square inch absolute;
e = Napierian logarithmic base = 2.71828;
G = specific gravity of gas (air = 1.00);
L = average length of gas column, feet; and
F = correction factor for taking into account the decreased density under flow conditions as compared with static conditions.

If deviation from Boyle's law and the average temperature of the column of gas are included in a formula to be used for calculating the pressure due to the weight of a moving column of gas the following relationship is obtained:

$$\left[\frac{P_s}{1+P_s b}\right] = \left[\frac{P_1}{1+P_1 b}\right] \left[e^{\frac{GLF}{53.34T}}\right].$$

[59] See table 37, appendix 5.
[60] See equation 15, appendix 5.

This formula is of the same form as that used to calculate the pressure due to the weight of a static column of gas (equation (17) of this appendix) with the exception that factor F is included to account for the decreased density of the gas in a moving column as compared with that of the gas in a static column. It is possible, therefore, to use the charts (figs. 49 and 50) that were devised for the calculation of the pressure due to the weight of a static column of gas to facilitate routine calculations of the pressure due to the weight of a moving column.

The effect of considering deviation from Boyle's law on the calculation of back-pressure observations is shown in the following example which is based on data obtained from a back-pressure test on a gas well:

Depth of producing sand, 4,990-5,010 feet;
Size of casing, 6⅝ inches (6.652 inches I. D.);
Specific gravity of gas, 0.6 (air=1.00);
GL, $0.6 \times 5{,}000 = 3{,}000$;
Average temperature of gas column, 80° F.;
Deviation coefficient, 0.0001 per pound per square inch;
Shut-in wellhead pressure, 1,700 pounds per square inch absolute.

Reading No.	Operating pressure at wellhead, lb. per sq. in. absolute.	Rate of flow of gas, M cu. ft. per 24 hrs.
1	1,695	5,000
2	1,687	10,000
3	1,635	25,000
4	1,493	50,000

Formation pressures, considering and not considering deviation of the gas from Boyle's law, are shown in the following tabulations:

Pressure data, deviation from Boyle's law considered		Pressure data, deviation from Boyle's law not considered		Rate of flow of gas, M cu. ft. per 24 hours
P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	P_f, lb. per sq. in. absolute	P_s, lb. per sq. in. absolute	
1,922.56	1,917.39	1,886.66	1,881.69	5,000
..	1,907.28	..	1,871.95	10,000
..	1,859.08	..	1,825.49	25,000
..	1,730.95	..	1,702.08	50,000

A comparison of the rate of flow Q and the pressure factor $P_f^2 - P_s^2$, considering deviation of the gas from Boyle's law, is shown below.

Plotting data, deviation from Boyle's law considered			Plotting data, deviation from Boyle's law not considered			Rate of flow of gas, M cu. ft. per 24 hours
P_f^2	P_s^2	$P_f^2 - P_s^2$	P_f^2	P_s^2	$P_f^2 - P_s^2$	
3,696.24	3,676.24	20.00	3,559.49	3,540.76	18.73	5,000
..	3,637.74	58.50	..	3,504.20	55.29	10,000
..	3,456.24	240.00	..	3,332.41	227.08	25,000
..	2,996.24	700.00	..	2,897.07	662.42	50,000

As shown in the above tabulations, the effect of deviation from Boyle's law in the proper interpretation of actual pressures that exist at the sand face of the well under consideration is appreciable. However, the effect of the deviation of the gas from Boyle's law on

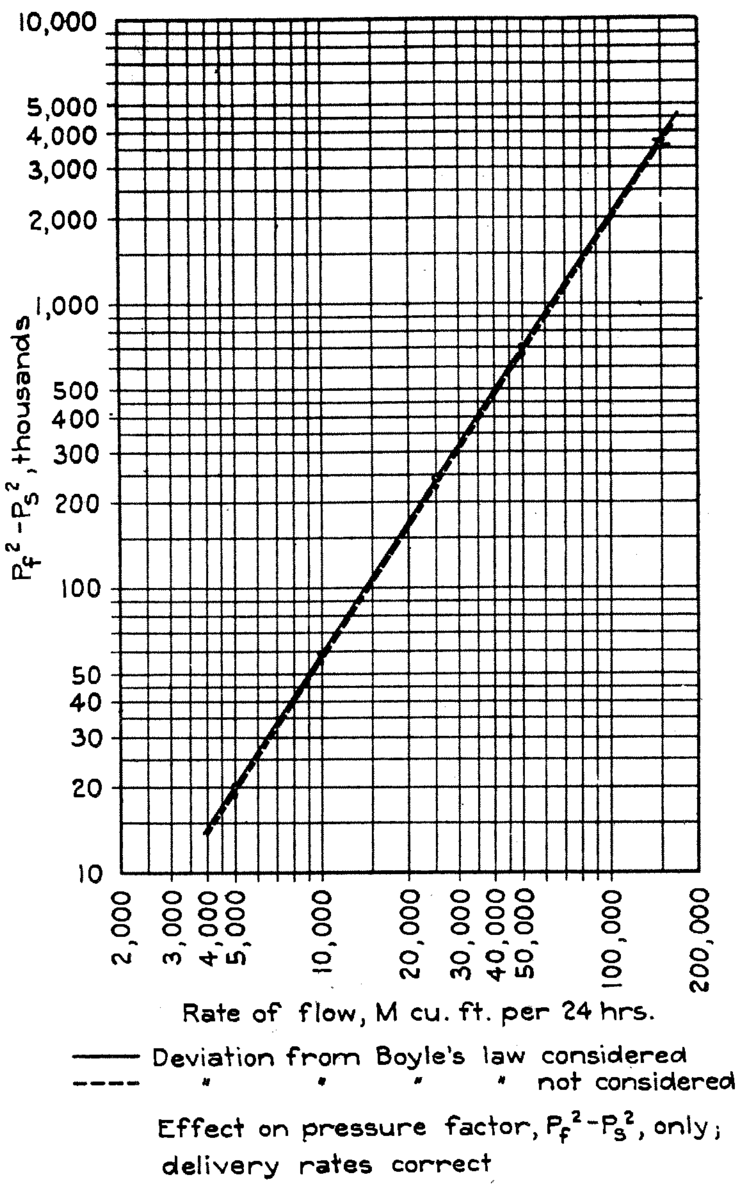


FIGURE 52.—Effect of deviation of gas from Boyle's law in computing results of a back-pressure test on a gas well

the position of the straight line representing the relationship between Q and the pressure factor $P_f^2 - P_s^2$ is virtually negligible, as is illustrated in figure 52, where the absolute open flows obtained from the two plotted relationships are about the same and there is a variation in the rates of flow at the same values of the factor $P_f^2 - P_s^2$ of only about 3 percent.

APPENDIX 7. MAXIMUM RATES OF FLOW OF GAS THROUGH PRODUCING STRINGS IN GAS WELLS

The maximum rate at which gas can be produced from a gas well under operating conditions depends on the characteristics of the productive formation and the flow capacity of the producing string in the well. The producing characteristics of the formation are defined by the relationship used in this report

$$Q=C(P_f^2-P_s^2)^n,$$

where Q=delivery rate,
P_f=absolute shut-in formation pressure,
P_s=absolute pressure at the sand in the well bore under flowing conditions,
and C and n=coefficient and exponent, respectively.

The absolute open flow of a gas well is defined in this report as the delivery rate that would occur if the pressure P_s at the face of the sand in the well bore were equivalent to atmospheric pressure. Since this value of P_s (atmospheric pressure) generally is small compared to the value of P_f, the absolute open flow of a well can be determined graphically by reading the value of Q corresponding to P_f^2 from the plotted relationship of Q and $P_f^2-P_s^2$. The absolute open flow of a gas well is greater than the maximum delivery rate at which gas can be produced from a well; the difference between absolute open flow and the maximum delivery rate depending upon internal diameter of the producing string, depth of well, specific gravity of gas, and establishment of stabilized flow conditions in the productive formation and the producing string. The flow of gas through the producing string is governed by the relationship [61]

$$Q=48{,}960\left[\frac{(P_1^2-P_w^2)\,d^{5\,1/3}}{GL}\right]^{1/2},$$

where Q=delivery rate,
P_1= pressure at bottom of well minus pressure due to weight of column of gas,
and P_w=pressure at wellhead.

Therefore, for the maximum delivery rate from a gas well, there is a corresponding value of $(P_f^2-P_s^2)$ where P_s is equivalent to atmospheric pressure plus the friction drop in the producing string plus the pressure due to the weight of the column of gas in the flow string. There are two methods that can be used to determine the maximum delivery rate at which gas can be produced from a gas well (the open flow of the well) from back-pressure data—the "cut-and-try" and the graphic methods.

"CUT-AND-TRY" METHOD OF DETERMINING MAXIMUM DELIVERY RATES FROM GAS WELLS

Tables 33, 34, 35, 36, 37, and 38 prepared for use in computing results of back-pressure tests can be used to facilitate calculations of open-flow deliveries through producing strings of the internal diameters listed in table 33. The procedure for calculating deliveries from gas wells by the "cut-and-try" method is as follows:

1. Assume some value of Q as the maximum delivery rate.
2. Compute the value of GL (specific gravity of the gas times the depth of the well).

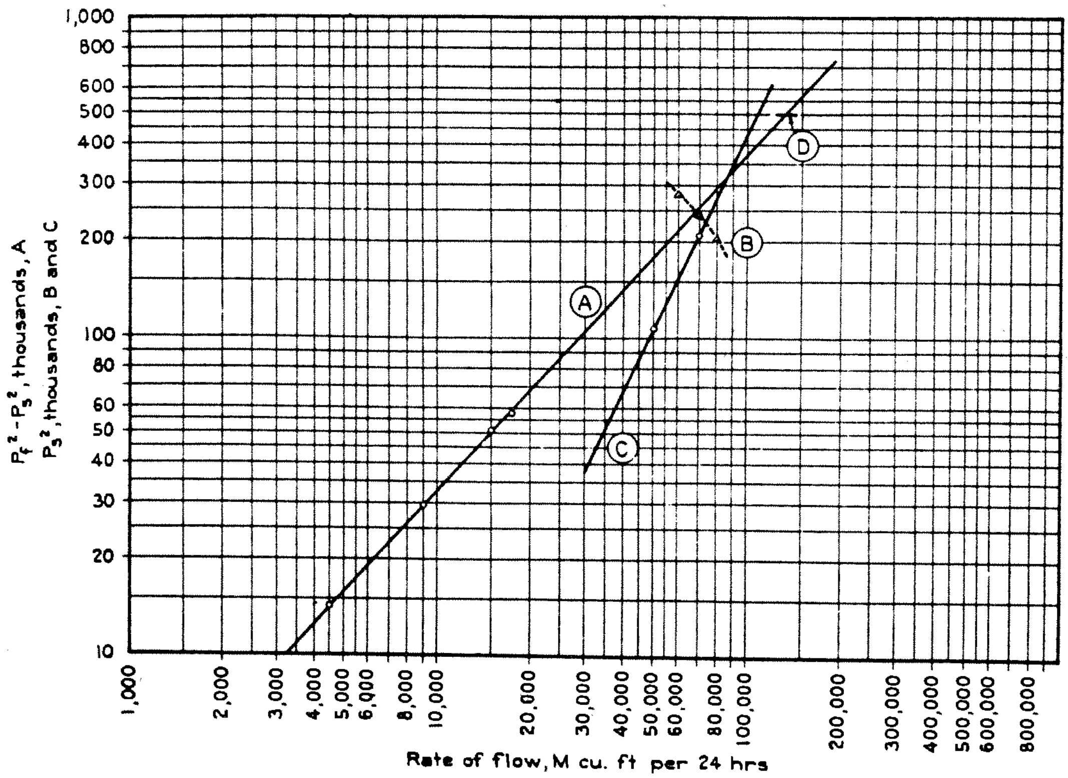
[61] See equation 1, appendix 5.

3. From table 33, appendix 5, determine the equivalent GL (the GL for 1-inch tubing that is equivalent to the computed GL for the producing string).
4. From table 34, appendix 5, determine the value of R corresponding to the equivalent GL and the assumed value of Q.
5. From table 35, appendix 5, determine the pressure drop in the producing string due to friction corresponding to the determined value of R and a pressure at the wellhead of 15 pounds per square inch.
6. Determine the ratio P_w/P_1, in which P_w is 15 pounds per square inch and P_1 is 15 pounds per square inch plus the pressure drop due to friction as determined in (5).
7. Obtain the value of factor F corresponding to the ratio P_w/P_1 from table 36, appendix 5.
8. Calculate GLF.
9. From table 37 obtain the pressure due to the weight of the column of gas corresponding to the value of GLF and the pressure at the wellhead plus the pressure drop due to friction.
10. Calculate P_s, the back pressure at the sand, by adding 15 pounds per square inch to the pressure drop due to friction plus the pressure due to the weight of the column of gas in the well.
11. Determine values of P_f^2 and P_s^2 by the aid of table 38, appendix 5.
12. Compute the value of $P_f^2-P_s^2$.
13. Read from the plotted relationship based on back-pressure data for the well the value of Q corresponding to the determined value of $P_f^2-P_s^2$.
14. If the computed value of Q is not the same as the assumed value it is necessary to repeat the procedure by assuming a new value of Q and to recompute the value of Q until the calculated value agrees with the assumed value. When these two values agree they represent the maximum delivery rate from the well as regulated by the producing string. Each set of calculations in the " cut-and-try " method can be used to guide the selection of a value to be given Q for subsequent calculations. It often is possible to determine the open flow through a producing string of any particular internal diameter with not more than 2 or 3 sets of computations.

The results of a back-pressure test on a well producing a large volume of gas under conditions of open flow in the Depew field, Oklahoma, are shown in figure 53. The specific gravity of the gas was 0.712, the size of flow string 6⅝ inches, and the depth of the well 3,200 feet. The absolute open flow of the well, as determined from the straight-line relationship A plotted in figure 53, was approximately 130,000,000 cubic feet of gas per 24 hours. The rate of delivery of gas with the 6⅝-inch casing open to the atmosphere and the different values obtained when making calculations by the " cut-and-try " method are shown in table 40.

The calculations are made as follows:

1. Assume that the open flow Q through the 6⅝-inch casing is 70,000,000 cubic feet of gas per 24 hours.
2. $GL=0.712\times 3.200=2,280$ (approximately).
3. From table 33, appendix 5, the equivalent GL corresponding to a GL of 2,280 for 6⅝-inch casing is 0.12.
4. From table 34, appendix 5, the value of R corresponding to an equivalent GL of 0.12 and a flow of 70,000,000 cubic feet of gas per 24 hours is 436.
5. From table 35, appendix 5, the pressure drop in the 6⅝-inch casing due to friction, corresponding to an R of 436 and a pressure at the wellhead of 15 pounds per square inch, is 421 pounds per square inch.
6. The ratio $P_w/P_1=\frac{15}{421+15}=\frac{15}{436}=0.034$.
7. From table 36, the value of F corresponding to a P_w/P_1 ratio of 0.034 is 0.67.
8. $GLF=2,280\times 0.67=1,528$.
9. From table 37, appendix 5, the pressure due to the weight of the column of gas, corresponding to a GLF of 1,528 and pressure at the wellhead plus the pressure drop due to friction of 436, is 23 pounds per square inch.
10. $P_s=436+23=459$ pounds per square inch absolute.



A, Relationship between Q and $P_f^2-P_s^2$ calculated from back-pressure data
B, " " Q and P_s^2 for gas flow into well bore
C, " " Q and P_s^2 for maximum gas flow through the producing string
D, Absolute open flow of well
Intersection of B and C gives maximum delivery rate under open-flow conditions

FIGURE 53.—Comparison of " absolute open flow " and open flow through the producing string of a gas well as made from back-pressure data

TABLE 40.—*Computation of "open flow" through the producing string of a gas well from back-pressure data by "cut-and-try" method*

Data	Assumed rate of flow, M cu. ft. per 24 hours	
	70,000	73,000
Specific gravity of gas .... (G)	0.712	0.712
Depth of well .... ft. (L)	3,200	3,200
Diameter of producing string .... in. (d)	$6\frac{5}{8}$	$6\frac{5}{8}$
Equivalent .... GL	0.12	0.12
R	436	455
Pressure drop in producing string .... lb. per sq. in.	421	440
Pressure ratio, P_{w}/P_1	0.034	0.033
Correction factor, *F*	0.67	0.67
GLF	1,528	1,528
Pressure due to weight of column of gas .... lb. per sq. in.	23	24
Back pressure at sand, P_s .... lb. per sq. in. abs.	459	479
Shut-in formation pressure, P_f .... lb. per sq. in. abs.	708	708
P_f^2 (thousands)	501.3	501.3
P_s^2 (thousands)	210.7	229.4
$P_f^2 - P_s^2$ (thousands)	290.6	271.9
Rate of flow read from plot of back-pressure data (curve *A*, fig. 53) .. M cu. ft. per 24 hrs.	78,000	73,500

11. Since P_f is 708 pounds per square inch absolute, then from table 38, appendix 5,

$$P_f^2 = (708)^2 = 501,300,$$

and

$$P_s^2 = (459)^2 = 210,700.$$

12. $P_f^2 - P_s^2 = 501,300 - 210,700 = 290,600$.

13. The rate of flow corresponding to a $(P_f^2 - P_s^2)$ of 290,600 is read from the straight-line relationship shown by curve *A*, figure 53, to be approximately 78,000,000 cubic feet of gas per 24 hours.

14. The assumed value of 70,000,000 cubic feet of gas per 24 hours is therefore too low. If an assumed value of *Q* is taken as 73,000,000 cubic feet of gas per 24 hours and the calculations repeated it will be found that the newly assumed value agrees closely with the value determined from the plotted relationship (see table 40). The open flow of the well through the 6⅝-inch casing therefore is approximately 73,000,000 cubic feet of gas per 24 hours.

GRAPHIC METHOD OF DETERMINING MAXIMUM RATES OF DELIVERY OF GAS FROM GAS WELLS

The graphic method of determining the open flow of a gas well through a producing string of a given internal diameter is based on virtually the same principles as the "cut-and-try" method. The back pressure P_s at the sand in the equation $Q = C(P_f^2 - P_s^2)^n$ is equal to a pressure of 15 pounds per square inch at the wellhead plus the pressure drop in the producing string due to friction plus the pressure due to the weight of the column of gas. The formula $Q = C(P_f^2 - P_s^2)^n$ expresses the relationship of flow from the sand in the reservoir to the well bore. The formula

$$Q = 48,960 \left[\frac{(P_1^2 - P_w^2)\, d^{5\ 1/3}}{GL}\right]^{1/2}$$

expresses the relationship of flow through the producing string.[62] This latter formula may be written

$$Q = 48,960 \frac{d^{8/3}}{\sqrt{GL}} (P_1^2 - P_w^2)^{1/2}.$$

Since P_w (atmospheric pressure) usually is small compared with P_1, the above formula may be written in the following form without introducing an appreciable error:

$$Q = 48,960 \frac{d^{8/3}}{\sqrt{GL}} (P_1^2)^{1/2}.$$

The pressure due to the weight of the column of gas in the producing string is computed from the formula [63]

$$P_1 = \frac{P_s}{e^{0.0000347GLF}},$$

and therefore, by substituting,

$$Q = 48,960 \frac{d^{8/3}}{\sqrt{GL}} \left(\frac{P_s}{e^{0.0000347GLF}}\right).$$

The graphic solution of the problem of open flow through any size of casing or tubing is determined from the intersection of the curve representing the relationship between Q and P_s in the above formula with the curve representing the relationship between Q and P_s in the flow formula, $Q = C(P_f^2 - P_s^2)^n$, for the particular gas

[62] See formula (1), appendix 5.
[63] Based on formula (15), appendix 5.

well. The tables in appendix 5 can be used to facilitate calculations when the following procedure is used.

1. Calculate the value of GL.
2. From table 33 determine the equivalent GL (the GL for 1-inch tubing equivalent to the computed GL for the producing string).
3. From table 34 determine values of R corresponding to the equivalent GL and any two assumed rates of flow. The values of R are considered equivalent to the values of P_1.
4. Calculate the ratios of P_w/P_1.
5. From table 36 determine the correction factors F corresponding to the ratios of P_w/P_1.
6. Calculate values of GLF.
7. From table 37 determine the pressures due to the weight of the column of gas corresponding to the pressure at the wellhead plus the pressure drop due to friction and values of GLF.
8. Calculate the pressures P_s by adding the pressure due to the weight of the column of gas to the pressure at the wellhead plus the pressure drop due to friction.
9. From table 38 determine the value of P_s^2.
10. Plot on the same sheet of logarithmic paper with the relationship between Q and $P_f^2-P_s^2$ the values of P_s^2 against the corresponding values of Q to give a curve showing the capacity of the producing string to deliver gas from any pressure P_s at the face of the sand.
11. From the plotted results of the back-pressure test where Q was plotted against $(P_f^2-P_s^2)$ determine a number of representative values of P_s^2 corresponding to different values of Q.
12. Plot the values of Q and P_s^2 determined directly from the results of the back-pressure test on the same sheet of logarithmic coordinate paper. A curve through the plotted points will give the capacity of the well to deliver gas against any back pressure P_s at the face of the sand.
13. The intersection of the plotted relationship Q versus P_s^2 for flow through the producing string with that for flow through the sand is the open flow through the producing string.

The graphic method is illustrated in figure 53. The procedure of calculation is as follows.

1. Since the specific gravity of the gas is 0.712 and the depth of the well 3,200 feet the value of GL is $0.712\times3{,}200=2{,}280$ (approximately).
2. From table 33, appendix 5, the equivalent GL corresponding to a GL of 2,280 for 6⅝-inch casing is 0.12.
3. Assume rates of flow Q of 50,000,000 and 70,000,000 cubic feet of gas per 24 hours. From table 34, appendix 5, the value of R corresponding to an equivalent GL of 0.12 and a flow of 50,000,000 cubic feet of gas per 24 hours is 311, and for a flow of 70,000,000 cubic feet of gas per 24 hours is 436. In other words, the values of P_1 (the pressure at the wellhead plus the pressure drop in the producing string due to friction) corresponding to rates of flow of 50,000,000 and 70,000,000 cubic feet of gas per 24 hours are taken as 311 and 436 respectively, because in these calculations P_1 is assumed to be equal to R.
4. Ratios of P_w/P_1 corresponding to rates of flow of 50,000,000 and 70,000,000 cubic feet of gas per 24 hours are 15/311 and 15/436, or 0.048 and 0.34, respectively.
5. From table 36, the correction factors F corresponding to the P_w/P_1 ratios for the two rates of flow are the same, or 0.67.
6. The values of GLF corresponding to the two rates of flow also are the same, or $2{,}280\times0.67=1{,}528$.
7. From table 37, the pressure due to the weight of the column of gas when the rate of flow is 50,000,000 cubic feet of gas per 24 hours (corresponding to a GLF of 1,528 and a pressure at the wellhead plus pressure drop due to friction of 311 pounds per square inch) is 17 pounds per square inch. Similarly, the pressure due to the weight of the column of gas when the rate of flow is 70,000,000 cubic feet per 24 hours (corresponding to a GLF of 1,528 and a pressure at the wellhead plus a pressure drop due to friction of 436 pounds per square inch) is 23 pounds per square inch.

8. The pressures P_s at the sand corresponding to rates of flow of 50,000,000 and 70,000,000 cubic feet per 24 hours therefore are 311+17 or 328 and 436+23 or 459 pounds per square inch, respectively.

9. The values of P_s^2 corresponding to flow rates of 50,000,000 and 70,000,000 cubic feet of gas per 24 hours, from table 38 are 107,580 and 210,700, respectively.

10. The relationship designated by C, figure 53, drawn through points $Q=50,000\ M$, $P_s^2=107,580$, and $Q=70,000\ M$, $P_s^2=210,700$, represents the maximum capacity of the 6⅝-inch casing to produce gas corresponding to the squares of different pressures at the sand.

11. The following tabulation shows different values of P_s^2 with corresponding values of Q, as determined from the plotted relationship between Q and $P_f^2-P_s^2$ from the back-pressure test on the well.

Q, rate of flow, M cu. ft. of gas per 24 hours	$P_f^2-P_s^2$, lb. per sq. in. squared, thousands	P_f^2, lb. per sq. in. squared, thousands	P_s^2, lb. per sq. in. squared, thousands
60,000	219	501	282
70,000	259	501	242
80,000	298	501	203

12. The relationship designated by B, figure 53, which represents the results of plotting Q against P_s^2 as obtained in (11), can be used for determining the capacities of the sand to produce gas against different back pressures at the sand face in the well bore.

13. The intersection of C and B, figure 53, at a rate of flow of approximately 73,000,000 cubic feet of gas per 24 hours gives the open flow of the well through the 6⅝-inch casing.

The graphic method of determining the open flow of a well through the producing string can be used advantageously to determine what the open flow would be if the well were cased or tubed with pipe of other internal diameters. This is illustrated by the following interpretation of the back-pressure data from the well as plotted in figure 53 and data showing maximum capacities of producing strings of different internal diameters that might be used in the well.

Data for determining the relationship between the rates of flow Q and the back pressure at the sand P_s for flows through producing strings of various internal diameters are shown in table 41. Tables 33, 34, 35, 36, 37, and 38, appendix 5, were used to facilitate the calculations indicated by table 41, and the procedure followed was as outlined previously in this report.

Values of P_s^2, the square of the pressure at the face of the sand, corresponding to different rates of flow from the well, as given in table 42, were calculated directly from the plotted results of the back-pressure test in figure 53. Rates of maximum flow Q, corresponding to the squares of different values of back pressure at the sand, that could be produced from the well through producing strings of various internal diameters are shown in figure 54. The figure also shows the rates of flow Q corresponding to different values of the back pressure squared P_s^2, for flow from the producing sand to the well bore. The intersection of the curve representing this latter relationship with the lines representing the relationship for maximum flow through the producing strings gives open flows that would occur through each producing string. The open-flow rates shown in table 43 were obtained from figure 54.

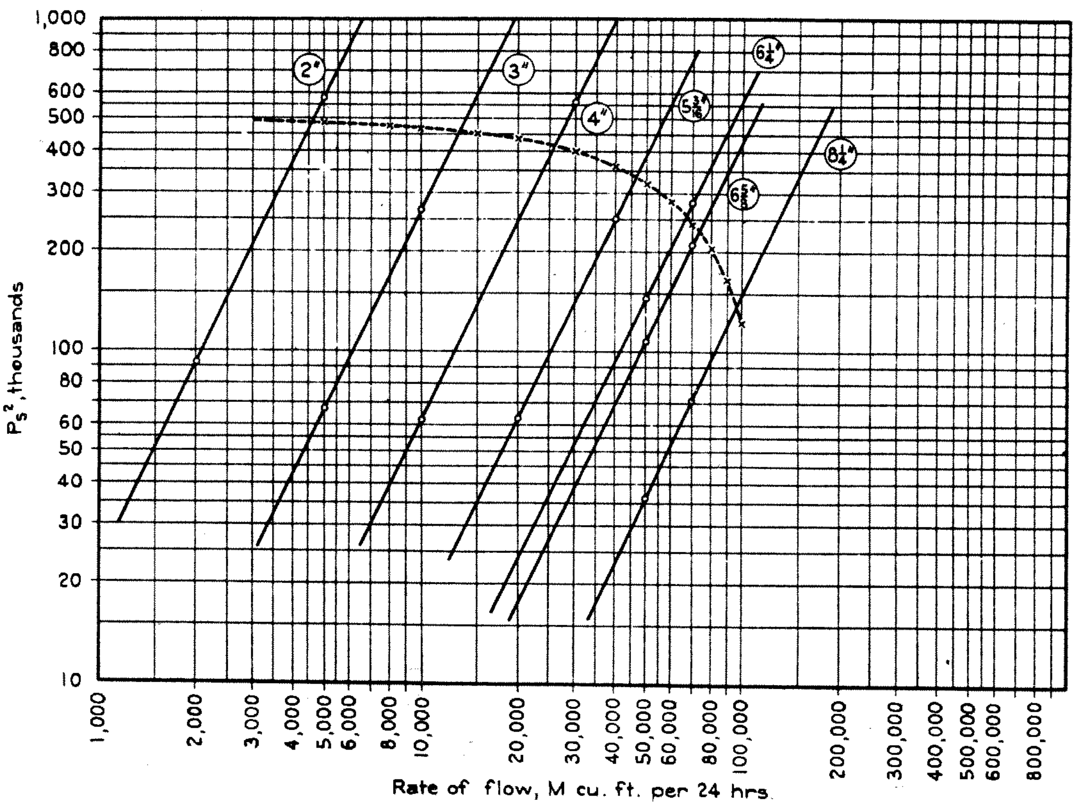
TABLE 41.—*Maximum capacities of producing strings of various internal diameters to deliver gas from a gas well under different pressure conditions at the sand*

Specific gravity of gas = 0.712; depth of well = 3,200 feet; GL = 2,280 (approximately)

	Nominal size and actual internal diameter of producing string, inches													
	8¼ 8.249		6⅝ 6.652		6¼ 6.287		5$\frac{3}{16}$ 5.192		4 4.026		3 3.068		2 2.041	
	Rate of flow, M cu. ft. per 24 hours		Rate of flow, M cu. ft. per 24 hours		Rate of flow, M cu. ft. per 24 hours		Rate of flow, M cu. ft. per 24 hours		Rate of flow, M cu. ft. per 24 hours		Rate of flow, M cu. ft. per 24 hours		Rate of flow, M cu. ft. per 24 hours	
	50,000	70,000	50,000	70,000	50,000	70,000	20,000	40,000	10,000	30,000	5,000	10,000	2,000	5,000
Equivalent GL	0.04	0.04	0.12	0.12	0.16	0.16	0.44	0.44	1.74	1.74	7.3	7.3	64.0	64.0
$R = P_1$ (approximate)	180	252	311	436	359	502	238	476	237	710	243	486	288	719
P_w/P_1	.083	.060	.048	.034	.042	.030	.063	.031	.063	.021	.062	.031	.052	.021
Correction factor F	.67	.67	.67	.67	.67	.67	.67	.67	.67	.67	.67	.67	.67	.67
Value of GLF	1,528	1,528	1,528	1,528	1,528	1,528	1,528	1,528	1,528	1,528	1,528	1,528	1,528	1,528
Pressure due to weight of gas column ... lb. per sq. in.	10	14	17	23	20	27	12	25	12	38	15	26	15	38
Pressure at sand, P_s ... lb. per sq. in. abs.	190	266	328	459	379	529	250	501	249	748	258	512	303	757
P_s^2 (thousands)	36.10	70.76	107.58	210.70	143.6	279.8	62.50	251.0	62.00	559.5	66.56	262.1	91.81	573.0

TABLE 42.—*Effect of back pressure at sand face on rates of delivery of gas from a gas well*

Rate of flow, M cu. ft. per 24 hours	$P_f^2 - P_s^2$, lb. per sq. in.[2] (thousands)	P_f^2, lb. per sq. in.[2] (thousands)	P_s^2, lb. per sq. in.[2] (thousands)
5,000	15.6	501.3	485.7
8,000	25.7	..	475.6
10,000	32.5	..	468.8
15,000	50.0	..	451.3
20,000	68.0	..	433.3
30,000	104.0	..	397.3
40,000	142.0	..	359.3
50,000	180.0	..	321.3
60,000	219.0	..	282.3
70,000	259.0	..	242.3
80,000	298.0	..	203.3
90,000	338.0	..	163.3
100,000	378.0	..	123.3



See table 41 for internal diameters of producing strings.

FIGURE 54.—Comparison of open-flow deliveries that would be obtained through producing strings of different diameters based on the results of a back-pressure test of a gas well

TABLE 43.—*Comparisons of open flows from a gas well through producing strings of different diameters in a gas well*

Size of producing string,[1] inches	Open flow, M cu. ft. per 24 hrs.
	130,000 (absolute)
$8\frac{1}{4}$	97,000
$6\frac{5}{8}$	73,000
$6\frac{1}{4}$	67,000
$5\frac{3}{16}$	46,500
4	26,000
3	13,200
2	4,600

[1] See table 41 for internal diameter of strings.

APPENDIX 8. CAUSE AND EFFECT OF ERROR IN BACK-PRESSURE DATA

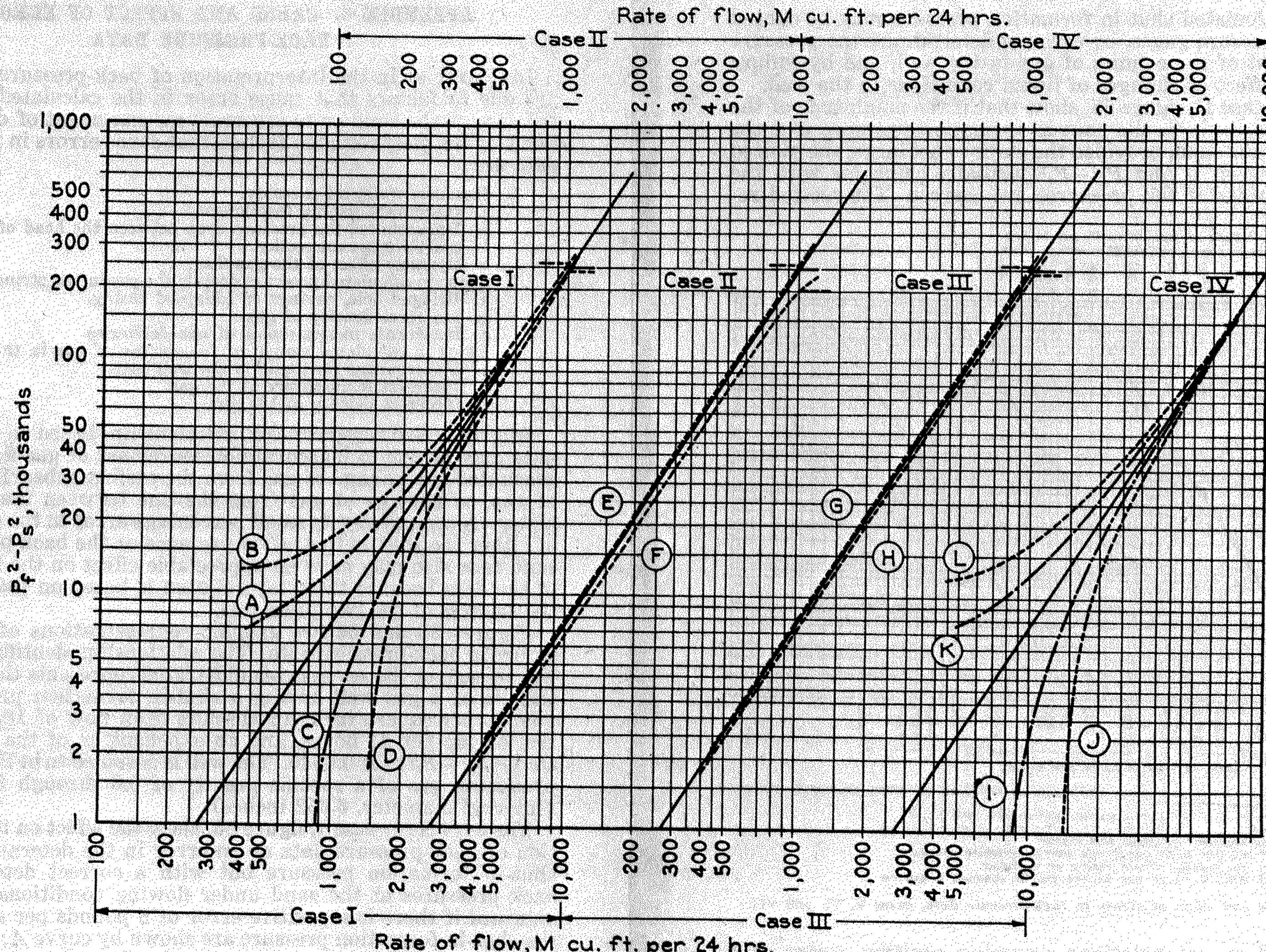
Inaccuracies in the interpretation of back-pressure tests usually are due to factors that cause error in the calculated pressures at the face of the sand or to incorrect measurement of delivery rates. Some of the most common factors that cause errors in back-pressure data are:

1. Incorrect wellhead pressure.
   a. Inaccurate gaging instrument.
   b. Unaccounted-for pressure drop between the head of the flow string and the gage connection.
   c. Dynamic effect of the gas flow.
2. Error in calculated pressure drop in the producing string due to friction.
   a. Bridged hole, cavings or collapsed casing.
   b. Incorrect density of gas.
   c. Inaccurate measurement of gas deliveries.
3. Error in calculated weight of the column of gas in the well.
   a. Unaccounted for liquid in the well bore.
   b. Incorrect temperature of the gas.
   c. Incorrect density of the gas.

Appreciable discrepancies in relationships based on back-pressure data may be due to inaccurate measurement of gas flow and to unaccounted-for leakage of gas from the casing, subsurface migration of gas, or leakage of gas from the line between the well and the meter. A comparatively small percentage error in the determination of either the shut-in formation pressure or the back pressure at the sand face also may have an appreciable effect on the interpretation of the data because the interpretation is based on the difference of the squares of the two pressures.

Figures 55 and 56 are graphic representations of the effect of errors in back-pressure data. The relationship identified by the solid line in each of the seven cases illustrated represents the true characteristic of a gas well having a shut-in formation pressure of 500 pounds per square inch, an absolute open flow of 10,000,000 cubic feet of gas per 24 hours, and an exponent, n, of the flow equation $Q=C(P_f^2-P_s^2)^n$ of 0.6545. The well is assumed to be 2,000 feet deep, producing gas of a specific gravity of 0.6 through $6\frac{5}{8}$-inch casing (internal diameter, 6.652 inches).

The curves for case I, figure 55, show the effect on the interpretation of back-pressure data of an error in the determination of the shut-in formation pressure but with a correct determination of back pressures at the sand under flowing conditions. The results obtained if there is a positive error of 5 pounds per square inch in the shut-in formation pressure are shown by curve *A*; for a positive error of 10 pounds per square inch in the shut-in formation pressure, by curve *B*; for a negative error of 5 pounds per square inch, by curve *C*; and for a negative error of 10 pounds per square inch, by curve *D*. In the particular case under discussion, if errors are made in determining the shut-in formation pressure the calculated values of $P_f^2-P_s^2$ corresponding to different measured delivery rates result in an erroneous interpretation of the delivery capacities of the well. The plotted data do not indicate actual conditions at low values of $P_f^2-P_s^2$, and the interpretation of delivery capacities throughout a large pressure range cannot be made properly.



Case I, Error in shut-in formation pressure, back pressure at sand correct
- A, Positive error of 5 pounds per square inch
- B, " " " 10 " " " "
- C, Negative " " 5 " " " "
- D, " " " 10 " " " "

Case II, Same error in shut-in formation pressure and back pressure at sand
- E, Positive error of 10 pounds per square inch
- F, Negative " " 50 " " " "

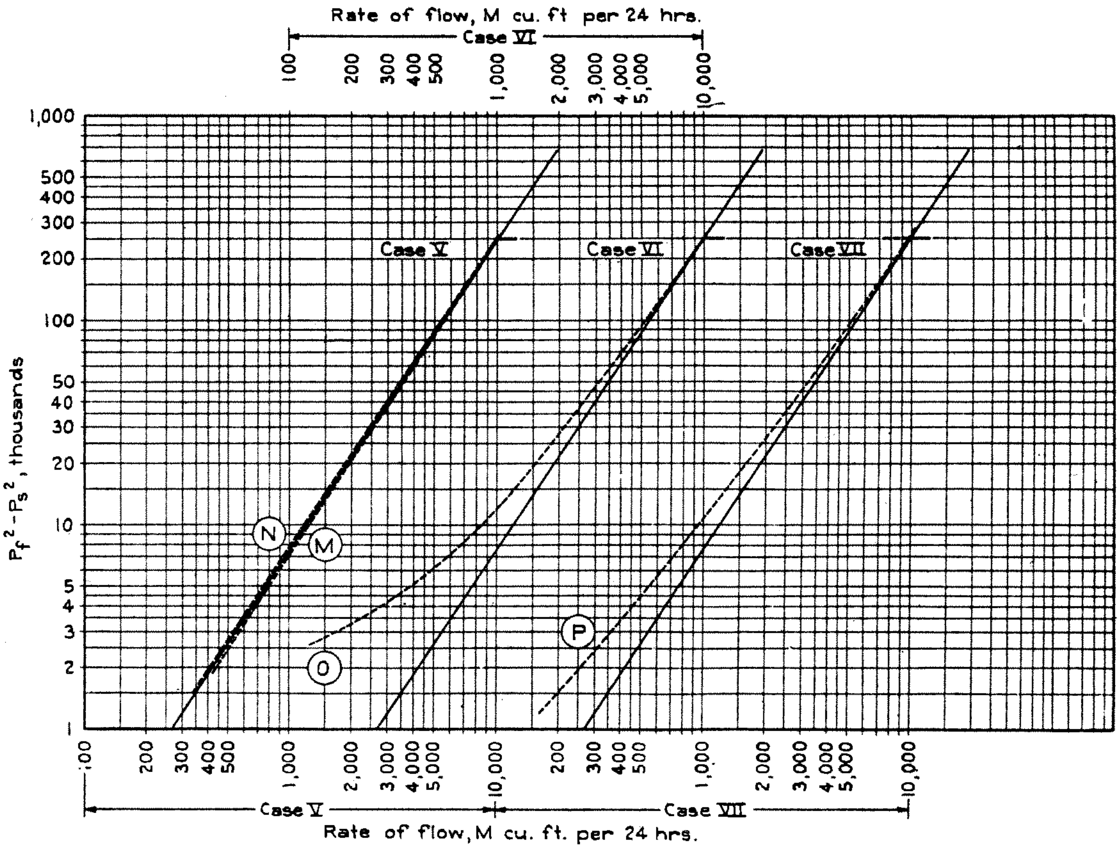
Case III, Error increasing with pressure in shut-in formation pressure and back pressure at sand
- G, Positive error of from 0 to 10 pounds per square inch
- H, Negative " " " 0 " 10 " " " "

Case IV, Error in back pressure at sand, increasing with pressure, shut-in formation pressure correct
- I, Positive error of from 0 to 5 pounds per square inch
- J, " " " " 0 " 10 " " " "
- K, Negative " " " 0 " 5 " " " "
- L, " " " " 0 " 10 " " " "

FIGURE 55.—Cause and effect of errors in back-pressure data, cases I, II, III, and IV

Errors in the calculated shut-in formation pressure may be caused by inaccurate pressure gages, by error in determining the pressure due to the weight of the column of gas in the well, and by failure to consider the effect of changes of liquid conditions in the well.

The curves in case II, figure 55, show that if the magnitude of the error is the same in both the shut-in formation pressure and the back pressure at the sand, provided the error is not large, the plotted relationship between Q and $P_f^2-P_s^2$ virtually coincides with the relationship obtained if the pressures are correct. The plotted re-



Case V, Error in back pressure at sand decreasing as pressure increases, shut-in formation pressure correct
M, Positive error of from 10 to 0 pounds per square inch
N, Negative " " " 10 " 0 " " " "
Case VI, Gas leakage between wellhead and meter
O, Leakage of 14,000 M cu. ft. per 24 hrs per lb. absolute pressure
Case VII, Continuous gas leakage from casing or wellhead
P, Leakage of 14,000 M cu ft per 24 hrs. per lb. absolute pressure

FIGURE 56.—Cause and effect of errors in back-pressure data, cases V, VI, and VII

lationship based on computations assuming positive errors of 5 pounds per square inch in the shut-in formation pressure and the back pressure at the sand coincided with the true relationship as closely as the results could be plotted. Results for positive errors of 10 pounds per square inch in the shut-in formation pressure and the back pressure at the sand are shown in curve *E;* and for negative errors of 50 pounds per square inch in both pressure determinations, by curve *F.* Substantially equal errors in the shut-in formation pressure and in the back pressure at the face of the sand may be caused by inaccurate pressure gages or by an unchanged column of liquid in the well bore during a back-pressure test.

The curves for case III, figure 55, show the effect of an error increasing with the values of both the formation pressure and the back pressure at the sand, such as may occur if through a faulty gage the errors in pressure readings change with pressure, and no account is taken of the erroneous readings in subsequent computations. The error, however, usually is small and if it is in the range of 0 to 5 pounds per square inch, the effect is negligible. Results for a positive error increasing with pressure from 0 to 10 pounds per square inch are shown by curve *G;* and for a negative error increasing with pressure of 0 to 10 pounds per square inch, by curve *H.*

The curves for case IV, figure 55, show the effect on interpretation of back-pressure data of an error increasing with the pressure, assuming that the shut-in formation pressure is correct and that the error is in the computed back pressure at the sand. Results for a positive error in the back pressure increasing with the value of the pressure from 0 to 5 pounds per square inch are shown by curve *I;* for a positive error of 0 to 10 pounds per square inch, by curve *J;* for a negative error of 0 to 5 pounds per square inch, by curve *K;* and for a negative error of 0 to 10 pounds per square inch, by curve *L.* The magnitude of the effect of such errors is appreciable at low values of $P_f^2 - P_s^2$ and, as in case I, the interpretation of delivery capacities throughout a large pressure range cannot be made properly.

The curves for case V, figure 56, show the effect of error in the back pressure at the sand when the error decreases as the pressure increases. As indicated by the curves, the effect of such an error is small. Results for a positive error in the back pressure at the sand when the error decreases from 10 to 0 pounds per square inch as the pressure increases are shown by curve *M;* and for a negative error, with the same change of error with an increase of pressure, by curve *N.*

Curve *O,* case VI, figure 56, shows the effect on the results of a back-pressure test of gas leakage between the wellhead and the meter when the pressure of the gas in the meter is virtually the same as at the wellhead. It is assumed that there is no leakage of gas at the wellhead during the observation of the shut-in pressure at that point. Calculations are based on a rate of leakage of 14,000 cubic feet of gas per 24 hours per pound absolute pressure. The magnitude of the effect of the leakage of gas on interpretation of delivery capacities is appreciable at low values of $P_f^2 - P_s^2$.

Curve P, case VII, figure 56, shows the effect of a continuous leakage of gas (during measurement of both shut-in and working pressures) from an opening in the casing or wellhead where the pressure at the point of leakage is the same as the pressure at the wellhead. The calculations are based on a leakage rate of 14,000 cubic feet of gas per 24 hours per pound absolute pressure.

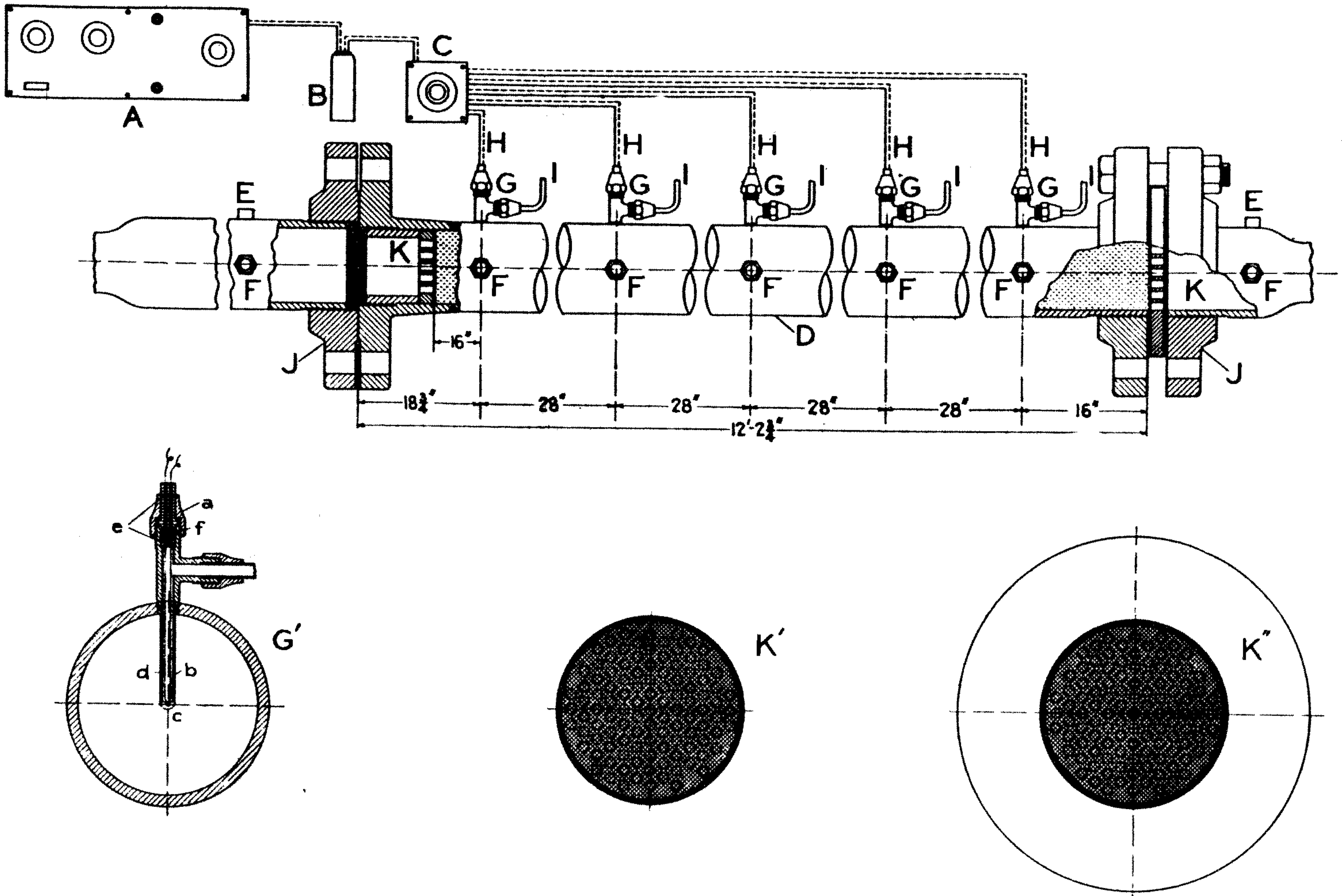
The graphic illustrations of the effect of error on the interpretation of back-pressure data emphasize the necessity of obtaining accurate data and the need for considering the factors that might influence measurements of the shut-in formation pressure, the back pressure at the sand, and the delivery rate.

APPENDIX 9. EXPERIMENTAL STUDY OF FLOW OF GAS THROUGH POROUS MEDIA

The character of the flow of gas through the producing formations and the pressure conditions within the reservoir fundamentally affect the absolute rate of availability of gas and the volume of gas that ultimately may be recovered from the reserves. Back-pressure tests of gas wells give useful information regarding the character of gas flow through the reservoir sands, pressure conditions within the reservoir, and the rate at which the gas is available. However, the information that can be obtained from tests is limited, and the effects of many separate and distinct factors are considered and grouped in the coefficient and exponent of the flow equation $Q=C(P_f^2-P_s^2)^n$. Therefore, an experimental study of flow of gas through porous media was made to supplement the results of the large number of back-pressure tests that have been made on gas wells. The experiments were conducted mainly to study the effects of the nature of any particular medium and of the pressure conditions that are imposed on the flow of gas through porous media. The effect of such factors as size, shape, and surface texture of the sand grains, porosity of the sand, distance of travel of the gas, and the surface area exposed to gas flow have been isolated insofar as the media available permitted.

The apparatus for the experimental tests consisted principally of steel flow tubes, pressure gages, instruments for measuring temperatures, and a prover for measuring the rates of flow of gas. The porous media were packed in the steel flow tubes and the pressure and temperature observations were made at different points along the tubes while gas was flowing through them at different rates.

The steel flow tube shown in figure 57 consists essentially of a section of steel tubing equipped with special flanges J on each end. Screen-covered perforated steel retaining plates K kept the porous medium in place in the flow tube. The retaining plate for the intake end was machined to fit the inside diameter of the tube and could be tightened against the porous medium in the tube by means of a follower ring; thus pressure could be applied to the material as it was being packed to obtain longitudinal uniformity in the consistency of the packed medium and to permit packing different materials to similar consistencies for comparative tests. The retaining plate at the discharge end of the tube was inserted between the flange faces. The length of the tube between the intake and discharge flanges was 12 feet 2¾ inches. Special temperature and pressure connections G, spaced 28 inches apart, each consisting of a brass tubing compression unit, a, with an inserted piece of copper tubing b, extending to the center of the tube, and covered at the lower end with a fine copper screen, c, made it possible to secure temperature and pressure observations at the centers of different cross sections of the tube. Thermocouple leads d were inserted in the copper tubing of the temperature-pressure connections through a fiber plug, e, which was packed off with a plastic composition rubber gasket, f. The pressure connection I was at the side of the fitting. Pressure connections F are for observing pressures along the insid



A—Potentiometer
B—Thermocouple cold junction
C—Ten-point rotary switch
D—Flow tube
E—Thermometer wells
F—Side static pressure connections
G—Combination thermocouple and pressure tap
G′—Detail of combination thermocouple and pressure tap
a—Brass tubing compression unit
b—Copper tube extending to center of flow tube
c—Copper screen
d—Chromel-copel thermocouple
e—Fiber plugs
f—Plastic composition rubber
H—Thermocouple leads
I—Pressure leads
J—Flanges on flow tube
K—Perforated plate and screen arrangement to retain sand
K′—Detail of plate and screen on inlet
K″—Detail of plate and screen on outlet

FIGURE 57.—Design of flow tubes used in study of flow of gas through porous media

wall of the tube. Pressure connections and thermometer wells *E* in the inlet and discharge fittings provide means of obtaining pressures and temperatures of the gas before and after flowing through the porous medium. The thermocouple leads *H* were connected through a rotary switch, *C*, and a thermocouple cold junction, *B*, to a potentiometer, *A*.

Five flow tubes were used during the tests; four consisted of only one pressure section, and the fifth was made up of four sections, as illustrated in figure 57. The dimensions of the tubes, all of which were of the same general design, are as follows:

Nominal internal diameter, inches	Distance between retaining plates (approximate), inches	Length of section (distance between thermocouple-pressure fittings), inches	No. of sections
3	44	28	1
3	144	28	4
2½	44	28	1
2	44	28	1
1½	44	28	1

The piping arrangement for the experimental tests is shown in figure 58. The gas was obtained from a gas well with a delivery capacity such that the maximum delivery rate required in the flow tests did not reduce the delivery pressure at the inlet end of the flow tube more than 5 pounds per square inch below that existing under shut-in conditions. Pressure-flow conditions following a change in the rate of production reached equilibrium rapidly, and the experimental work was expedited greatly since not more than 2 or 3 minutes were required for stabilizing delivery rates. Gas was delivered from the well into the piping system through the throttling valve *A*. The 4-inch flange *D*, into which an orifice plate could be inserted, was installed downstream from the throttling valve. A thermometer well, *B*, and a pressure connection, *C*, were provided on the upstream side of flange *D* for making pressure and temperature observations. The 4-inch flange, with its inserted orifice, thermometer well, and pressure connection, was used as a critical-flow meter to measure delivery rates under conditions of critical flow for purposes of calibration and for an occasional check on other gas measurements. The gas was allowed to pass through the flow tube packed with a porous medium, *H*, and was measured again through one or both meter runs *K* with provers *N*.

The orifices used in prover *N* at the start of the flow investigation were calibrated for velocities corresponding to a differential pressure range of 10 to 40 inches of water. Measurement of flow rates by means of the critical-flow meter at *D*, figure 58, was used as a standard for the calibrations. A length of 2-inch pipe was used in the set-up at *H* during the calibration tests, and the only change in the connections made after calibration was completed was replacement of the section of 2-inch pipe by the previously fitted flow tube and approach fittings, thus eliminating the possibility of discrepancies caused by the effect of the approach fittings.

As gas was produced from the well through 8¼-inch casing and under the low velocities of flow during the experimental tests, it was improbable that entrained liquid accompanied gas from the well. Nevertheless, a vertical drip was installed in the line between the

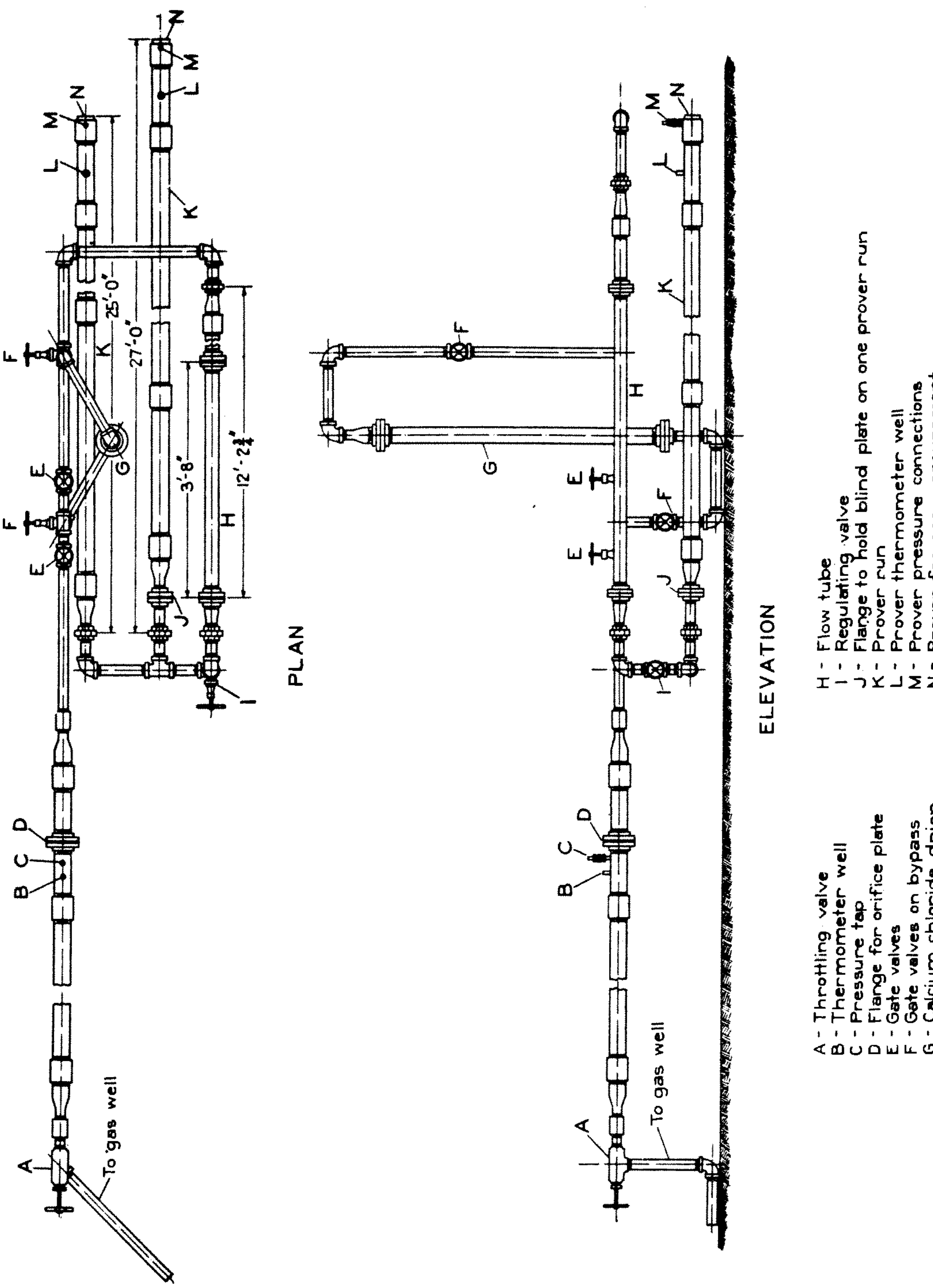


FIGURE 58.—Set-up of equipment used in study of flow of gas through porous media

well and the experimental set-up to serve as a protection against liquids entering the flow tubes. However, to determine definitely whether or not the data were influenced by the effect of liquid from the well or by the adsorption of water vapor or heavy hydrocarbon fractions present in the gas by the medium in the flow tubes, a calcium-chloride-filled tube and bypass were provided in the intake line to the flow tube. (See *G*, fig. 58.) Five tests were made to determine the character of the flow through fine-grained sand—3 with gas flowing through the calcium-chloride drier before entering the sand tube and 2 with gas flowing through the sand tube directly from the well. Comparison of the results obtained under the two conditions of flow showed that the moisture in the gas had a negligible effect on the flow of gas through the sands.

Studies were made of the character of flow of gas through the following granular materials:

(1) Lead shot of density 11.201 grams per cubic centimeter, with a smooth surface texture.

(2) Ottawa sand of density 2.6416 grams per cubic centimeter, with rounded grains having a surface texture slightly rougher than lead shot. The smaller grains were slightly angular.

(3) Wilcox sand of density 2.6412 grams per cubic centimeter. The large grains were similar in shape and surface texture to the Ottawa sand grains of corresponding screenings. The small grains, however, were more angular and rougher than the large grains.

(4) Building sand of following densities.

Screen size, meshes per inch	Density, grams per cubic centimeter
Through 20 on 28	2.6252
Through 28 on 35	2.623
Through 48 on 65	2.6286

The grains were angular and the surface slightly rough.

(5) Gravel of density 2.6321 and less angular than building sand. The surface of the grains was relatively rough.

The sand was screened in the laboratory at the Bureau of Mines Petroleum Experiment Station, Bartlesville, Okla., through a Hummer vibrating screen. A comparison of the screen analyses before and after the materials were packed in the tubes showed that there was no appreciable crushing of the grains in the packing process and that the amount of very fine material removed by the gas during flow tests was negligible.

The materials were packed in the tubes by pounding the walls of the filled tube with hammers and maintaining a pressure on the movable inlet plate by means of the threaded follower, while the tubes were in a vertical position. Rapping the tubes and applying pressure were continued until further vibration and pressure had no appreciable effect on the degree of packing of the media or until a predetermined voidage was obtained.

Void space in porous media usually is expressed in terms of the percent porosity and is the ratio of the void spaces within the material to the gross space occupied by the material multiplied by 100. For determining the percent porosities of the media the volume of the space in the tubes between the retaining plates was calibrated with water and the respective densities and weights of the different materials used to pack the tube were determined carefully. The void space in the packed material and the percent porosity were calculated as follows:

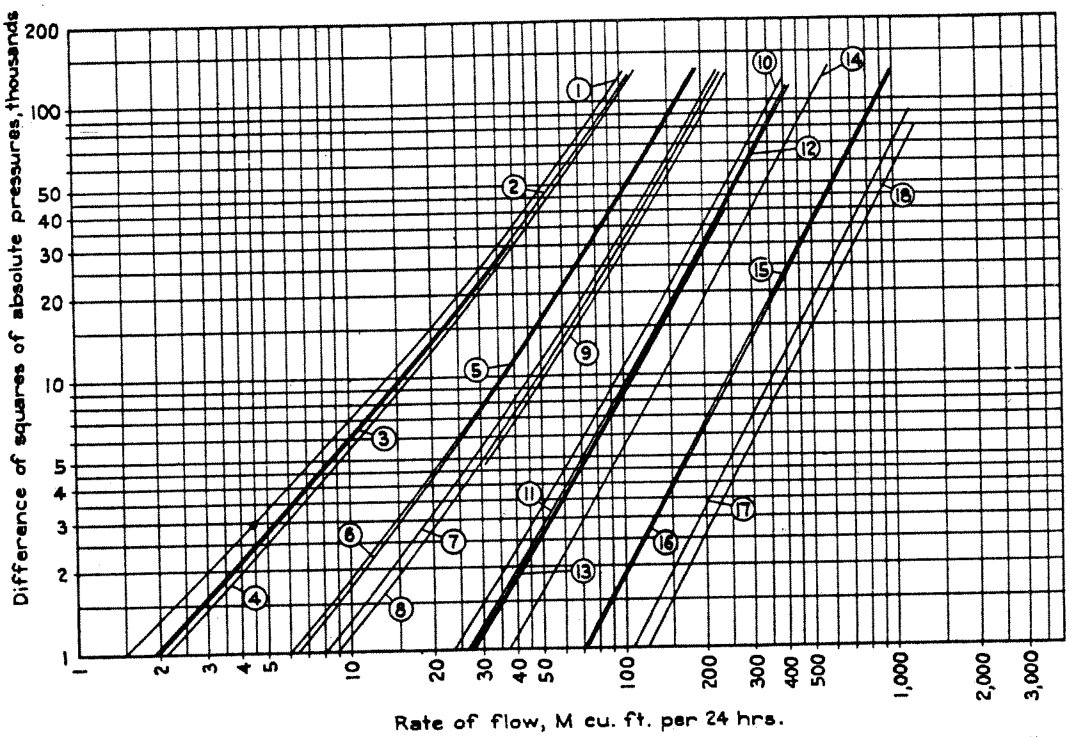
$$\text{Void space in the material} = \left(V - \frac{M}{d}\right), \text{ and}$$

$$\text{percent porosity} = \left(V - \frac{M}{d}\right)\left(\frac{100}{V}\right),$$

where V=gross space occupied by material, cubic centimeters;
M=weight of material, grams; and
d=density of material, grams per cubic centimeter.

The condition of the material packed in the flow tube to each of several porosities remained unchanged when subjected to pressure of the flow of gas. On three of the media, however, flow tests were conducted at each of several different porosities.

The experimental procedure in the majority of the tests was similar. All pipe and pressure connections were tested for leakage be-



Designation	Sand separation	Kind of sand	Porosity	Designation	Sand separation	Kind of sand	Porosity
1	120 - 170	Wilcox	32.63	10	28 - 35	Ottawa	33.20
2	120 - 170	Ottawa	35.04	11	20 - 28	Building	33.98
3	120 - 170	Wilcox	32.56	12	20 - 28	Ottawa	31.43
4	Run of mine	Wilcox	30.52		20 - 28	Building	33.75
5	48 - 65	Wilcox	32.09	13	20 - 28	Ottawa	31.34
6	Run of mine	Ottawa	28.62	14	14 - 20	Gravel	35.39
7	48 - 65	Building	35.50	15	No. 9	Shot	32.47
8	48 - 65	Ottawa	35.27	16	No. 12	"	35.34
9	28 - 35	Building	36.53	17	No. 5	"	34.67
				18	No. 1	"	34.57

Results of tests conducted on 3-inch flow tube
3 and 13, Results of tests conducted on 28-inch section of long flow tube
Other tests conducted on 28-inch section of short flow tubes

FIGURE 59.—Effect of grain size and shape on flow of gas through unconsolidated porous media

fore the first reading and at intervals during the test. The maximum differential pressure across the packed tube was imposed during the first of the series of tests, and the rates of flow of gas were decreased in the test series irrespective of whether the inlet or discharge pressure was varied, except during a few tests on loosely-packed tubes in which the magnitude of the flow was first increased and then decreased in the test series. All data were obtained under stabilized conditions of temperature and pressure, 30 to 40 minutes being required for temperatures to reach equilibrium on the initial flow through the more permeable media. Nine to fifty-two pressure adjustments were made during each test or included in each test series.

Three or four variations over a differential pressure range from 40 to 10 inches of water usually were obtained for each orifice in the prover. Frequently one orifice was replaced by another of a different size so the same rate of flow could be measured under various differential pressures to check the calibration of the respective orifices.

Because only very small differences in the pressures at the center and at the wall of the flow tube at corresponding longitudinal points

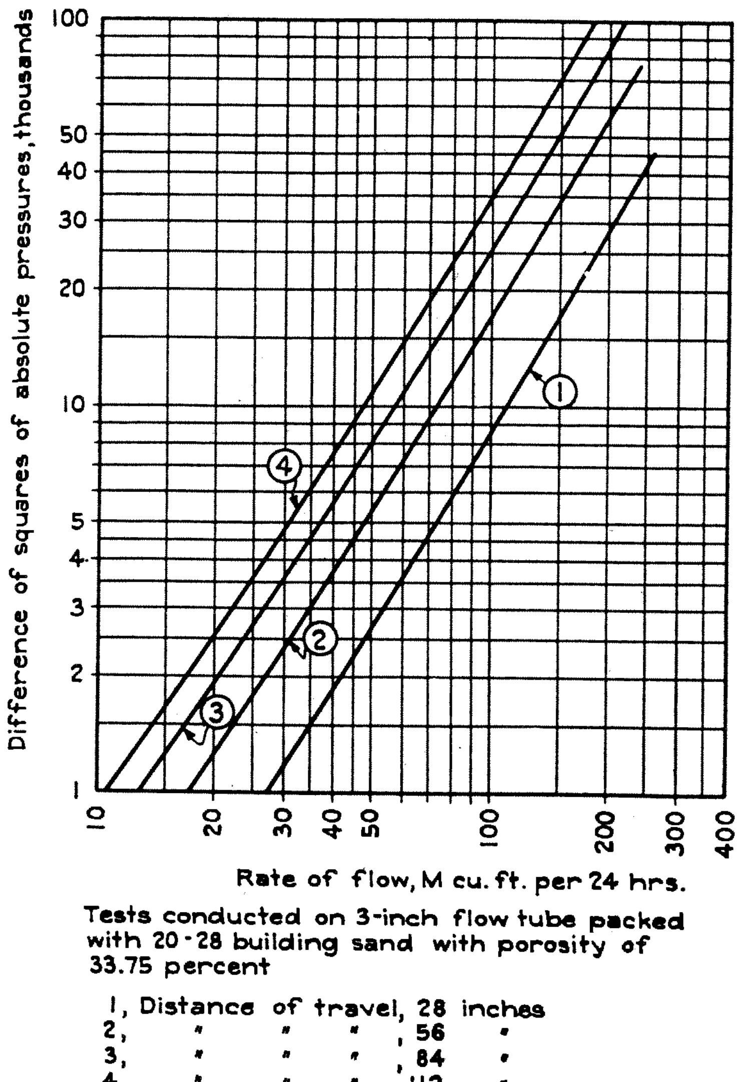
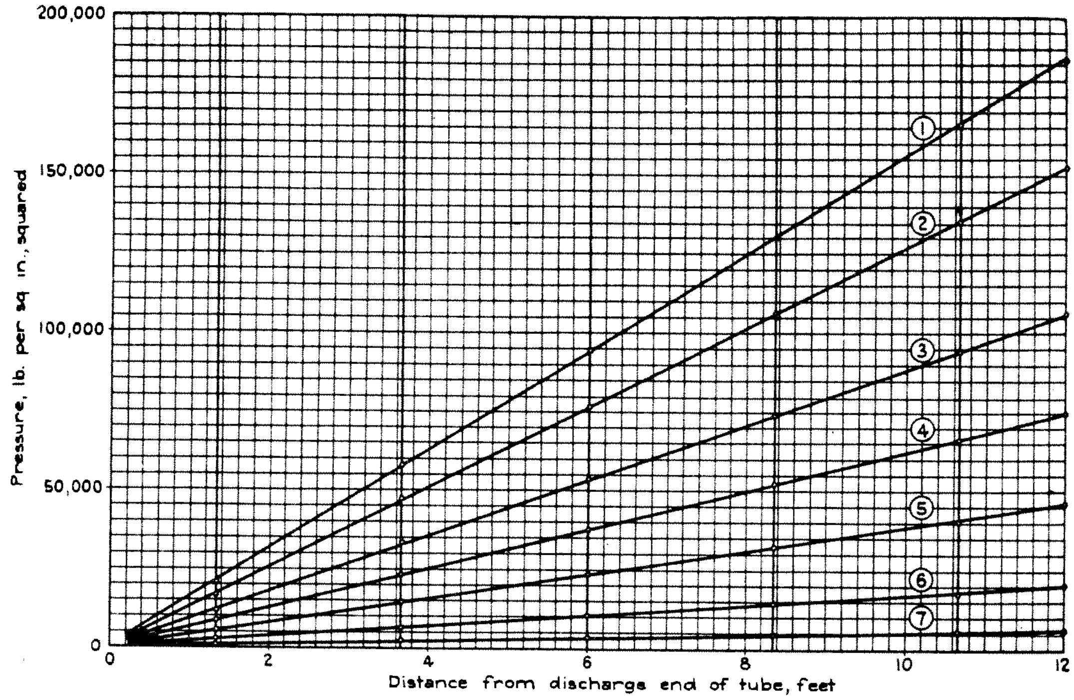


FIGURE 60.—Effect of distance of travel on flow of gas through unconsolidated porous media

were noted, the pressures at the walls of the flow tubes were recorded for only a few of the tests. To determine the effect of the magnitude of the mean pressure on the flow of gas through the porous media, comparative tests were made in which the inlet and discharge pressures, respectively, were varied. Thus, data were obtained for comparison of low rates of flow under pressures slightly greater than 1 atmosphere (14.4 pounds per square inch) and under pressures of approximately 30 atmospheres. The effect of the magnitude of the inlet pressure was determined by tests in which the inlet pressure was maintained at 265 pounds per square inch and at 437 pounds per square inch absolute, respectively. The longitudinal pressure gradient throughout the length of the material was established from data obtained for flow of gas through the multisection tubes equipped with five sets of equally spaced pressure and temperature connections. Several series of tests were made in which data were obtained for a comparison of the character of the flow of gas through porous material packed in 3-inch, 2½-inch, 2-inch, and 1½-inch nominal diameter flow tubes.



Gas volumes at pressure of 14.4 lb. per sq. in absolute, temperature of 60°F., specific gravity of 0.697 (air=1.00), and flowing temperature of 70°F.

Tests conducted on 3-inch flow tube packed with 20-28 Ottawa sand with porosity of 31.34 percent

1, Rate of flow, 158.68 cubic feet per minute
2, " " " , 141.53 " " " "
3, " " " , 115.14 " " " "
4, " " " , 94.10 " " " "
5, " " " , 71.32 " " " "
6, " " " , 43.82 " " " "
7, " " " , 21.37 " " " "

FIGURE 61.—Linear relationship between pressure squared and distance of travel of gas through unconsolidated porous media

Static pressures obtained during the experimental tests were measured with dead-weight gages or by liquid columns, depending on the magnitude of the pressures. All gage connections were made with copper tubing and cinch fittings. During the progress of the experimental tests the dead-weight gages were checked against each other at higher pressures and against a mercury column under lower pressures.

The study of flow of gas through porous media gave much valuable information on the effect of the size, shape, and roughness of the sand, distance of travel of gas under different differential pressures, diameter of flow tube, and porosity of the sand. Examples of these results are shown in figures 59 to 63, inclusive.

The curves shown in figures 59, 60, 62, and 63 can be approximated by straight lines on the logarithmic charts conforming to equations in the form

$$Q = C(P_a^2 - P_b^2)^n,$$

where Q=rate of flow, thousands of cubic feet per 24 hours;
C=coefficient;
P_a=pressure at upstream face of porous medium, pounds per square inch absolute;
P_b=pressure at downstream face of porous medium, pounds per square inch absolute; and
n=exponent, equivalent to the tangent of the angle between the straight line approximating the relation of Q to $(P_a^2 - P_b^2)$ and the vertical axis.

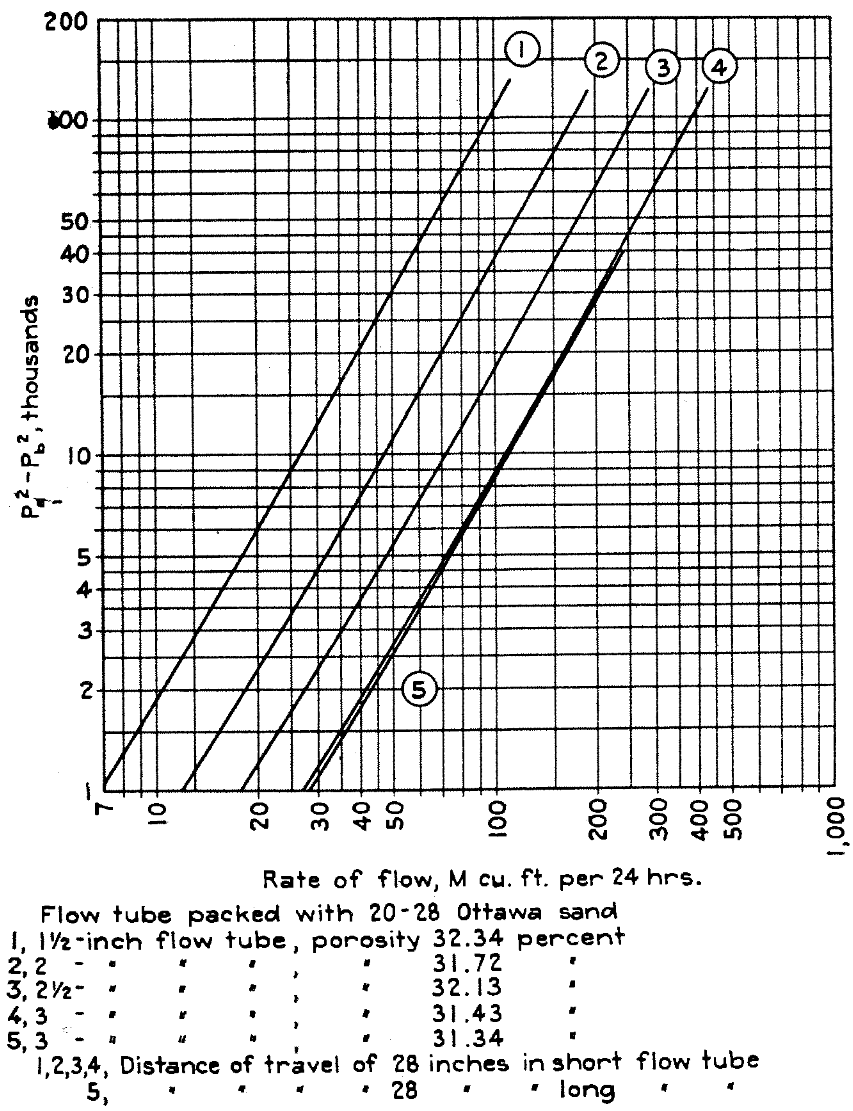
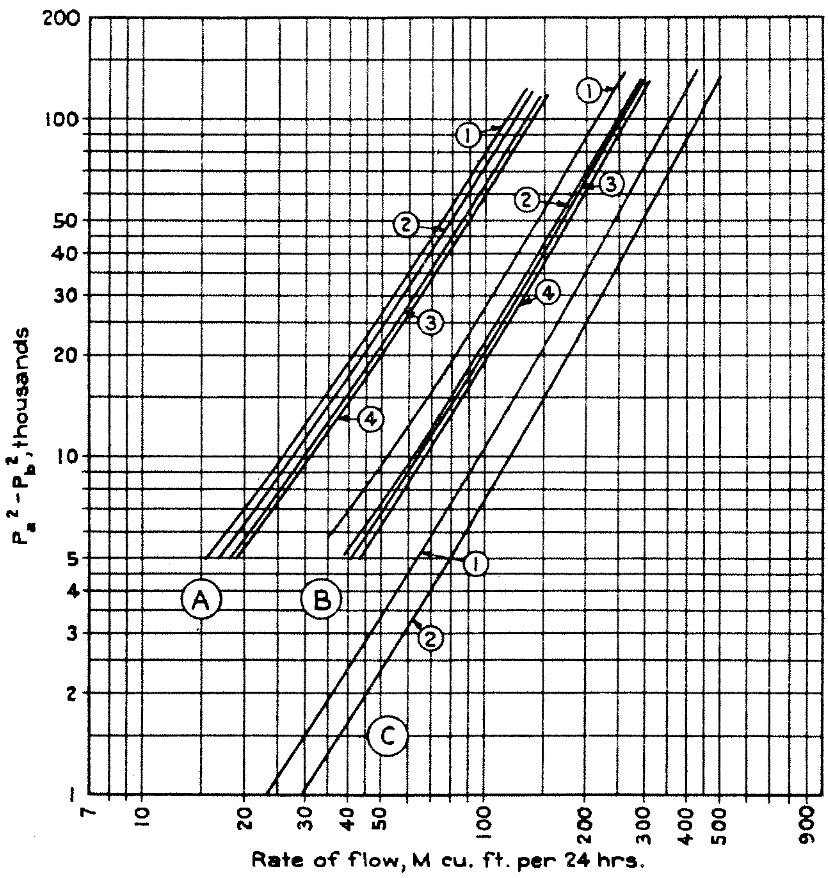


FIGURE 62.—Effect of diameter of flow tube on flow of gas through unconsolidated porous media

The curves in figure 59 show the relationships between the rate of flow and the pressure factor for flow of gas through the 3-inch flow tube packed with the different porous media and indicate mainly the effect of grain size and shape on the flow characteristic. The porosities of the different materials were not uniform so the differences in porosities had an indirect influence and must be considered when the curves in figure 59 are compared. The size and shape of the grain evidently have a pronounced effect on the coefficient C of the flow equation, because the values of the rates of flow at a difference of the squares of the upstream and downstream pressures of 50,000 ranged from 940,000 cubic feet of gas per 24 hours for the No. 1 lead shot to 52,000 cubic feet per 24 hours for the 120-170 mesh Wilcox sand. The grain size and shape evidently also affect exponent n of the equation of flow, as evidenced by the gradual in-



Test conducted on 2½-inch flow tube packed with 48-65 Wilcox sand
A, 1, Porosity, 32.36 percent 3, Porosity, 34.33 percent
2, " , 33.47 " 4, " , 34.87 "

Test conducted on 3-inch flow tube packed with 28-35 building sand
B, 1, Porosity, 36.53 percent 3, Porosity, 39.29 percent
2, " , 38.46 " 4, " , 39.86 "

C, Test conducted on 3-inch flow tube packed with 28-35 Ottawa sand
1, Porosity, 33.20 percent 2, Porosity, 35.21 percent

FIGURE 63.—Effect of porosity on flow of gas through unconsolidated porous media

crease in the slope of the tangents to the curves with an increase of grain size. The curves indicate also that there is a noticeable curvature in the relationship at low values of $P_a^2 - P_b^2$ for small grain sizes (for example, 120-170 Wilcox sand).

The curves in figure 60 show that the distance of travel of the gas through the 20-28 mesh building sand packed in the 3-inch flow tube on the flow characteristic has little or no effect on exponent n of the flow equation because the curves are substantially parallel. However, there is a noticeable change in coefficient C with changes in distance of travel of gas through the tubes. For example, the rates of flow corresponding to a pressure factor of 10,000 range from 109,000 to 47,500 cubic feet of gas per 24 hours for the shortest and longest distances of travel, respectively, used in the experimental tests. The results of the experiments indicate also that the pressure squared is a linear function of the distance along the flow tube expressible by an equation of the form

$$P^2=a+bs,$$

where P=pressure at any point along the tube,
s=distance along the tube, and
a and b=experimental constants.

Figure 61 represents the linear relationship between pressure squared and the distance obtained from one particular series of experimental tests.

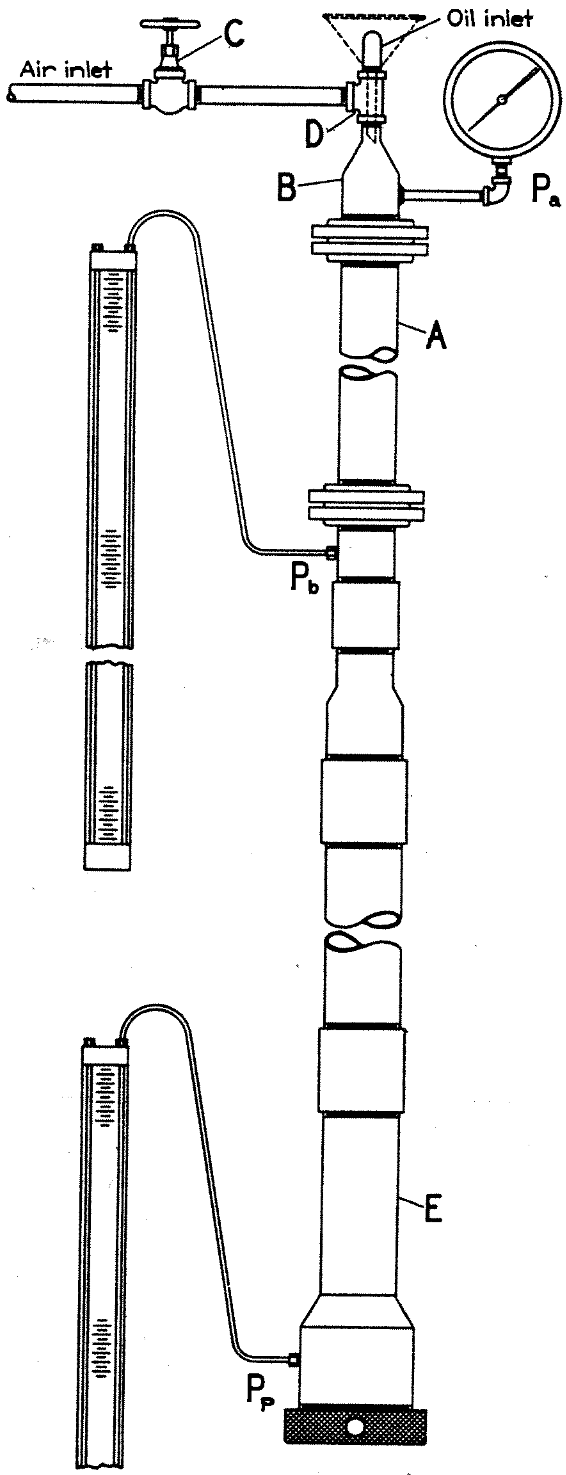
Figure 62 shows the general effect of the diameter of the tube on the characteristic of flow of the gas through 1½-, 2-, 2½-, and 3-inch tubes packed with 20-28 mesh Ottawa sand. The curves indicate that there is, for all practical purposes, little or no effect on exponent n of the flow equation but a noticeable effect on coefficient C because the actual range of flow rates at a pressure factor of 10,000 was from 26,800 to 111,000 cubic feet of gas per 24 hours. The changes in flow rates were approximately proportional to the ratios of the squares of the respective diameters.

A comparison of the curves in figure 63 shows that for all practical purposes the porosity of a sand affects only coefficient C of the flow equation. The curves designated by A, figure 63, show the results of flowing gas through 48-65 mesh Wilcox sand packed to different porosities in a 2½-inch tube; the curves designated by B show the results of flowing gas through 28-35 mesh building sand packed to different porosities in a 3-inch tube; and those designated by C show the results of flowing gas through 28-35 mesh Ottawa sand packed to different porosities in a 3-inch tube. In each case, the curves are practically parallel within the range of pressure and flow where data were obtained, indicating little or no effect of differences in porosity on exponent n of the flow equation.

APPENDIX 10. EXPERIMENTAL STUDY OF THE EFFECT OF LIQUID ON FLOW OF AIR THROUGH POROUS MEDIA

An investigation is being conducted in connection with the study of gaging gas-well deliveries to determine the effect of liquid in the void spaces of porous media on the character of gas flow through bonded and uncemented sands. Only the results obtained from that part of the investigation which deals with the effect of a constant quantity of liquid in the pore spaces of the material on the character of the flow of air through unbonded sands will be described.

The arrangement of apparatus used is shown in figure 64. The apparatus consists primarily of a flow tube, a prover for measuring gas delivery rates, and gages for measuring pressures. The flow tube A, which is a 1½-inch flanged pipe nipple approximately 20 inches long, is filled with sand. The sand is held in place within the flow tube by a screen arrangement which is virtually the same



A, 1½-inch flow tube; B, 1½-inch to 1-inch swedge;
C, valve on air inlet; D, tee for introducing oil
or air to flow tube; E, 2-inch prover;
P_a, upstream pressure on flow tube;
P_b, downstream " " " ";
P_p, pressure on 2-inch prover

FIGURE 64.—Arrangement of apparatus used for study of effect of liquid on flow of air through unconsolidated porous media

as that used in the study of the flow of gas through porous media described in appendix 9 and illustrated in figure 57. The flow tube was maintained in a vertical position during the tests, and the air flowed downward. A 1½- by ½-inch swedge, *B*, with a ½-inch tee was screwed into the upstream flange of the flow tube so that one outlet was at the side and the other above the tube. The ½-inch air inlet was connected into the side opening of the tee, and the flow of air into the test apparatus was controlled and regulated by a valve, *C*. While a test was in progress the top opening of tee *D* was closed with a ½-inch bull plug. Liquid was introduced into the system after removing the bull plug from the tee by pouring the liquid into a glass funnel inserted in the tee. A pressure connection, (P_b), was made to the 1½-inch nipple screwed into the downstream flange of the flow tube and to the 2- by ½-inch swedge at P_a. The pressure P_a was observed with a spring pressure gage and P_b with a manometer. A 1½-inch collar, 1½- by 2-inch swedge, 2-inch collar, 2-inch nipple 20 inches long, 2-inch collar, and 2-inch prover were connected in the order named below the 1½-inch nipple screwed into the flange at the downstream end of the flow tube. A pressure connection, P_P, was used to measure pressures on the prover by means of a manometer. Any liquid that flowed through the sand was collected in a glass beaker placed below the prover.

Three series of tests were conducted with the apparatus shown in figure 64.

Case I. Flow of air through a 20-30 separation [64] of sea sand wetted with a light-grade lubricating oil.
Case II. Flow of air through a 20-30 separation of river sand wetted with a light-grade lubricating oil.
Case III. Flow of air through a 20-30 separation of sea sand wetted with water.

The following procedure was used in studying the flow of air through a 20-30 separation of sea sand wetted with a light-grade lubricating oil (case I) and is representative of that used in all of the tests. Flow tube *A*, figure 64, was packed with the 20-30 separation of sea sand and connected into the apparatus between the flanges. Air was allowed to flow through the tube, and observations were made of the air pressures at P_a and P_b—to find the pressure drop through the packed tube—and at P_P to find the corresponding rate of flow of air through the tube. This procedure was followed for several different pressure-flow conditions, as shown in test 1, table 44, and the data were used to determine the flow characteristics of air through dry sand. The bull plug in the tee *D* then was removed, and 25 cm³ of light-grade lubricating oil was poured into the flow tube. After the bull plug was replaced a second series of observations of pressures was taken under the conditions shown in test 2, table 44. Several minutes were allowed to elapse for the oil to become distributed throughout the sand and for the approximate stabilization of pressure-flow conditions before the first pressure reading was made. An additional 25 cm³ of oil then was introduced at the top of the flow tube, and a third series of observations of pressures and rates of flow was obtained (see test 3, table 44). Finally an additional 25 cm³ of oil was added, making a cumulative

[64] Sand that would pass through a 20-mesh screen and be retained on a 30-mesh screen.

total of 75 cm^3, and a fourth series of observations of pressures and rates of flow was obtained, for which the data are shown as test 4, table 44.

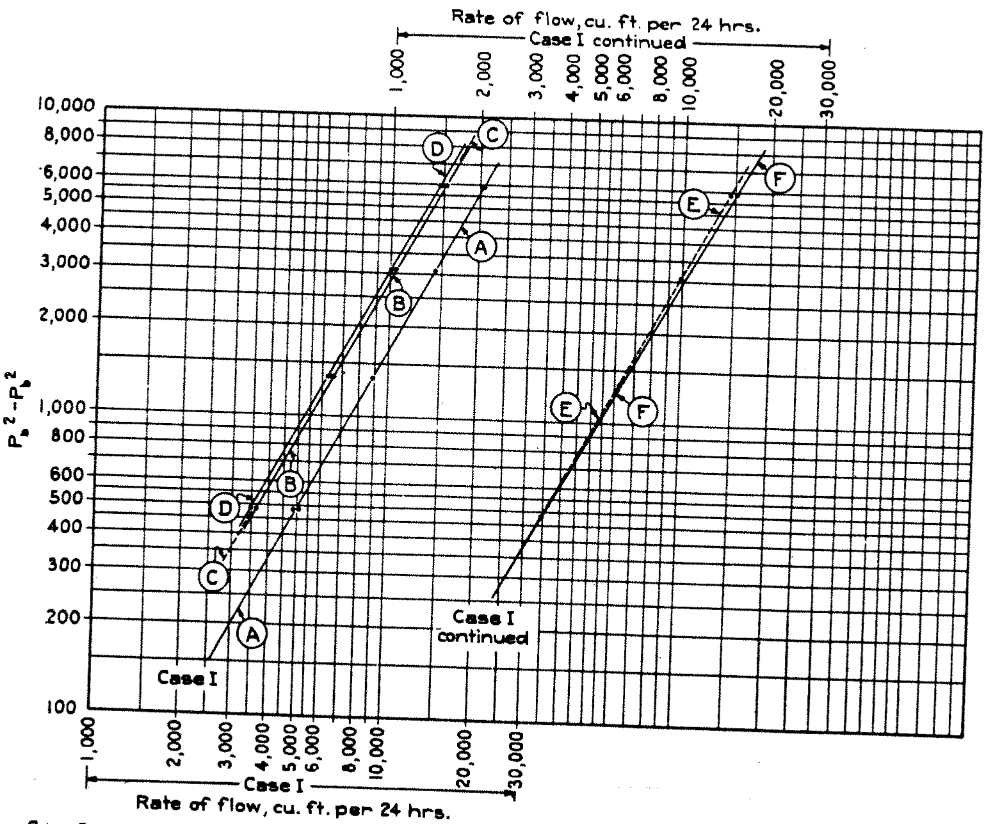
The results derived from the calculations of the data are shown in case I, figure 65. The relationship between the rate of flow and the difference of the squares of the inlet and outlet pressures on the flow tube for the flow of air through dry sand is shown by curve *A*. The results of test 2, which was performed after 25 cm^3 of light-grade lubricating oil was added to the system, are shown by curve *B*—the results of tests 3 and 4, after totals of 50 and 75 cm^3 of oil, respectively, had been added to the system are shown by curves *C* and *D*. The straight lines (*A*, *B*, *C*, and *D*, case I, fig. 65) representing the relationships between flow rates and pressures under

TABLE 44.—*Data and results of tests for flow of air through a 20–30 separation of sea sand wetted with a light-grade lubricating oil*

Test No.	Reading No.	Pressures on flow tube, lb. per sq. in. abs. P_a	P_b	$P_a^2 - P_b^2$, thousands	Rate of flow, cu. ft. per 24 hours	Remarks
1	1	77.90	15.05	5.841	20,400	Dry sand.
	2	56.90	14.71	3.022	14,190	
	3	39.40	14.53	1.341	8,845	
	4	26.40	14.44	0.488	5,005	
	5	26.40	14.53	0.486	4,873	
2	6	77.90	14.75	5.850	15,130	25 cm^3 of light-grade lubricating oil added before test.
	7	56.90	14.56	3.026	10,310	
	8	39.40	14.47	1.343	6,480	
	9	39.40	14.61	1.338	6,375	
	10	26.40	14.70	.481	3,588	
	11	20.20	14.50	.198	2,087	
3	12	77.90	14.73	5.851	14,570	25 cm^3 of light-grade lubricating oil added before test—total of 50 cm^3 for tests 2 and 3.
	13	56.90	14.53	3.027	9,895	
	14	39.40	14.60	1.339	6,330	
	15	26.40	14.69	.481	3,580	
	16	20.20	14.50	.198	2,051	
	17	77.90	14.75	5.851	14,980	
4	18	77.90	14.72	5.851	14,460	25 cm^3 of light-grade lubricating oil added before test—total of 75 cm^3 for tests 2, 3, and 4.
	19	56.90	14.55	3.026	9,960	
	20	39.40	14.46	1.343	6,210	
	21	39.40	14.60	1.339	6,180	
	22	26.40	14.69	.481	3,495	
	23	20.20	14.50	.198	1,993	
	24	77.90	14.74	5.851	14,820	

the different conditions of wetting of the sand with oil are virtually parallel, indicating equal values of exponent n in the flow equation $Q=C(P_a^2-P_b^2)^n$ throughout the range of pressure-flow conditions observed (see appendix 9). However, as established by the four tests coefficient C in the equation differs. The presence of the oil in the pores of the sand in the flow tube evidently causes a decrease in the flow rates corresponding to different values of $(P_a^2-P_b^2)$ compared with the flow through the dry sand. A comparison of curves *A* and *B*, for example, shows that at the same value of $P_a^2-P_b^2$ the rate of flow through the sand after 25 cm^3 of oil was added was approximately 27 percent less than the rate of flow through the dry sand. Comparison of curves *B* and *D*, however, shows that the addition of 50 cm^3 more of oil caused a further decrease in the delivery capacity of the sand of only about 2 percent. In other words, virtually all of the decrease in the permeability of the sand to gas occurred after the addition of the first 25 cm³ of oil and more oil had only a negligible effect upon the delivery capacity of the sand.

The data, tests 3 and 4, table 44, were supplemented at the beginning and at the end of each series by "check" observations of pressures and flow rates at the maximum rate of the test series, to determine the effect of an unavoidable small loss of oil during a particular test. For instance, in test 3 the rate of flow corresponding to a $P_a^2-P_b^2$ value of 5,851 at the beginning of the test

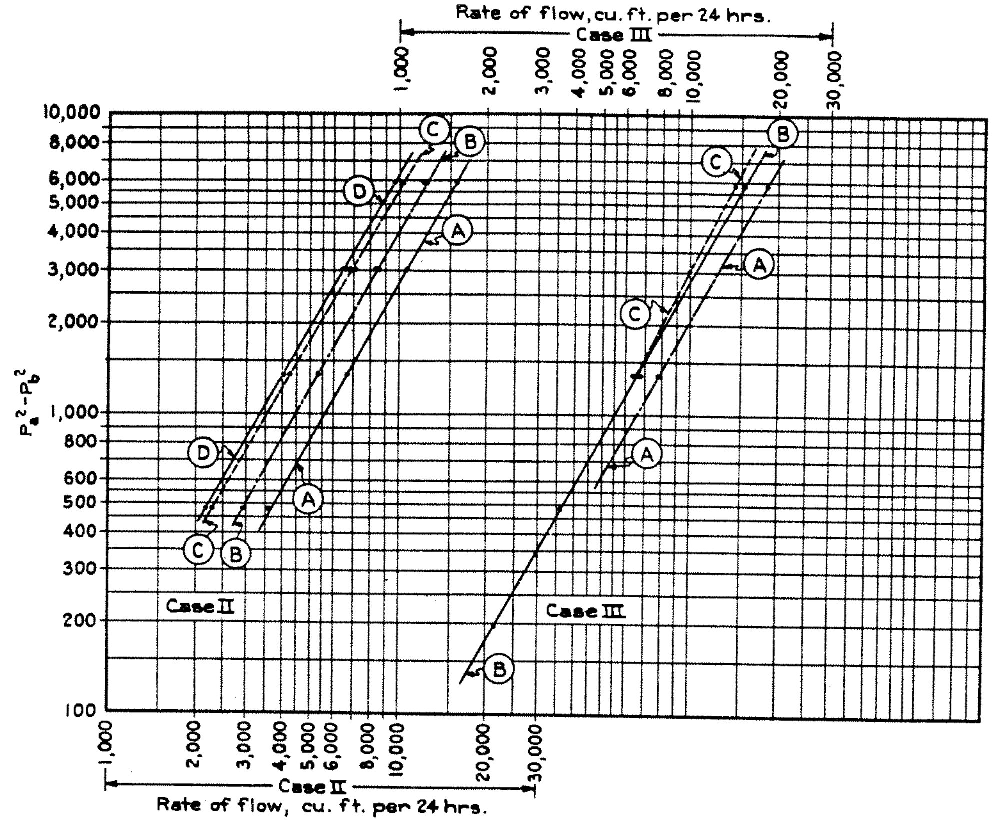


Case I, Flow of air through 20-30 separation of sea sand wetted with light lubricating oil
A, Dry sand
B, After adding 25 cm³ of light lubricating oil
C, " " 50 " " " "
D, " " 75 " " " "
Comparison of E and F indicates loss of liquid from packed tube during test series

FIGURE 65.—Effect of liquid on flow of air through unconsolidated porous media, case I

was 14,570 cubic feet of air per 24 hours, and the rate of flow corresponding to the same $P_a^2-P_b^2$ value at the end of the test was 14,980 cubic feet of air per 24 hours—an increase of 410 cubic feet (2.8 percent) per 24 hours. Curve *E*, case I, figure 65, is based on observations under conditions of the maximum flow of air at the beginning of the test and curve *F* on observations under conditions of maximum flow at the end of the test. The comparison of curves *E* and *F* shows that there is a small change in exponent *n* of the flow equation $Q=C(P_a^2-P_b^2)^n$ due to the loss of liquid during the test.

Twenty five cm³ of the oil that had been introduced into the sand was recovered from the flow stream at the discharge end of the prover during the stabilization period before observations were taken for test 4. Possibly some oil also may have been discharged from the sand and become deposited on the walls of the discharge fittings during the stabilization period before observations were made in test 3. Comparison of the curves in case I, figure 65, indicates that under the maximum flow rate used in the tests a condition of near-saturation existed after the introduction of the first 25 cm^3 of oil into the sand before the observations in test 2 were made.



Case II, Flow of air through 20-30 separation of river sand wetted with light lubricating oil
A, Dry sand
B, After adding 25 cm^3 of light lubricating oil
C, " " 50 " " " " "
D, " " 100 " " " " "

Case III, Flow of air through 20-30 separation of sea sand wetted with water
A, Dry sand
B, After adding 50 cm^3 of water
Comparison of B and C indicates loss of water during test series

FIGURE 66.—Effect of liquid on flow of air through unconsolidated porous media, cases II and III

Except for the total amount of oil added to the sand the procedure of the experimental tests on the flow of air through the flow tube packed with a 20-30 separation of river sand was the same as through the 20-30 separation of sea sand. First, a series of observations was obtained for the flow of air through dry sand; second, observations were obtained after 25 cm^3 of light-grade lubricating oil had been poured into the top of the flow tube; third, a test was conducted after another 25 cm^3 of oil was added; and fourth, a test was made after 50 cm^3 more was added, making a total of 100 cm^3 of oil added to the sand in the flow tube. The data and results of the calculations of this set of tests are given in table 45, and the interpretation of the data are shown in case II, figure 66.

The relationship for flow of air through the dry sand is shown by curve *A;* for flow of air through the sand after the addition of 25 cm^3 of oil, by curve *B;* for flow of air through the sand after the addition of a total of 50 cm^3 of oil, by curve *C;* and after the addition of a total of 100 cm^3 of oil, by curve *D*. The straight lines representing the relationships between the rate of flow and the difference between the squares of the flowing pressures are virtually parallel, and there is no change in exponent n of the flow equation throughout the range of data. However, there is a noticeable decrease in the ability of the sand to pass gas, as the quantity of oil added to the sand was increased from 25 to 100 cm^3. For instance, the rate of flow corresponding to a value of $(P_a^2-P_b^2)$ of 2,000 for curve *A* (flow of air through dry sand) is approximately 8,400 cubic feet

TABLE 45.—*Data and results of tests for flow of air through a 20–30 separation of river sand wetted with a light-grade lubricating oil*

Test No.	Reading No.	Pressures on flow tube, lb. per sq. in. abs.		$P_a^2 - P_b^2$, thousands	Rate of flow, cu. ft. per 24 hours	Remarks
		P_a	P_b			
1	1 2 3 4 5	77.90 56.90 39.40 26.40 77.90	14.79 14.58 14.47 14.70 14.79	5.849 3.025 1.343 .481 5.849	15,850 10,780 6,650 3,552 15,850	Dry sand.
2	6 7 8 9 10 11	77.90 56.90 56.90 39.40 26.40 77.90	14.64 14.51 14.76 14.54 14.50 14.65	5.854 3.028 3.020 1.341 .487 5.853	12,350 8,335 8,760 5,370 2,892 12,590	25 cm^3 of light-grade lubricating oil added before test.
3	12 13 14 15 16 17 18	77.90 56.90 56.90 39.40 39.40 26.40 77.90	14.56 14.47 14.65 14.49 14.84 14.52 14.56	5.856 3.029 3.023 1.342 1.332 .486 5.856	10,280 6,910 7,025 4,240 4,290 2,290 10,240	25 cm^3 of light-grade lubricating oil added before test—total of 50 cm^3 for tests 2 and 3.
4	19 20 21 22 23 24 25	77.90 56.90 56.90 39.40 39.40 26.40 77.90	14.55 14.47 14.82 14.48 14.80 14.51 14.55	5.856 3.029 3.024 1.342 1.333 .487 5.858	9,710 6,735 6,506 4,072 4,075 2,190 10,010	50 cm^3 of light-grade lubricating oil added before test—total of 100 cm^3 for tests 2, 3, and 4.

of air per 24 hours, whereas the rates of flow corresponding to this same value of $(P_a^2-P_b^2)$ for curves *B, C,* and *D* are approximately 6,700, 5,400, and 5,100 cubic feet of air per 24 hours respectively. The decreases in flow rates for curves *B, C,* and *D* compared with curve *A*, therefore, are approximately 20, 36, and 40 percent, respectively.

In case II, tests 2 and 3, only a negligible quantity of liquid actually was noticed in the flow stream at the discharge end of the prover, although 25 cm^3 of oil was introduced into the sand in the flow tube before each test. However, while the pressure conditions were becoming stabilized before taking observations for test 4, where an additional 50 cm^3 of oil was placed in the flow tube, a further and more appreciable quantity of oil was recovered from the discharged flow.

In the third case, a study was made of the flow of air through a 20-30 separation of sea sand wetted with water. As shown in table 46, two observations (1 and 2) were made to establish the relationship for the flow of air through the dry sand, following which 9 observations were made after 50 cm^3 of water had been added to the dry sand. The results of the tests are shown graphically in case III, figure 66. Curve *A* is based on flow data for the dry sand, and curves *B* and *C* were obtained after the sand had been wetted with 50 cm^3 of water. The variation between curves *B* and *C* is due to the unavoidable loss of a small quantity of water from the sand during the test. As shown by the curves, there was a decrease in the ability of the sand to pass gas of approximately 16 percent due to the addition of the 50 cm^3 of water.

TABLE 46.—*Data and results of tests for flow of air through a 20–30 separation of sea sand wetted with water*

Test No.	Reading No.	Pressures on flow tube, lb. per sq. in. abs.		$P_a^2 - P_b^2$, thousands	Rate of flow, cu. ft. per 24 hours	Remarks
		P_a	P_b			
1	1	77.90	14.92	5.845	18,270	Dry sand.
	2	39.40	14.71	1.336	7,700	
2	3	77.90	14.71	5.852	14,160	50 cm^3 of water added.
	4	56.90	14.55	3.026	9,980	
	5	39.40	14.47	1.343	6,635	
	6	39.40	14.61	1.338	6,440	
	7	26.40	14.47	.488	3,602	
	8	26.40	14.72	.480	3,660	
	9	20.20	14.50	.198	2,109	
	10	77.90	14.76	5.850	15,280	
	11	39.40	14.63	1.338	6,755	

An interpretation of the results of the tests in case III indicates that the 50 cm^3 of water more than sufficed to saturate the sand under the maximum differential pressure of the test. Evidently, the first two observations of test 2 were recorded while a supersaturated condition existed. It was noticed also that the loss of water from the sand was greater under conditions of near-saturation than the loss of oil in either case I or case II.

The results of the tests (cases I, II, and III) indicate that the effect of a constant quantity of liquid in the pore space of the sand is confined mainly to the coefficient of the flow equation and that usually the presence of liquid has a noticeable effect on the ability of the sand to pass gas.

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