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Unique wireline retrievable tool permits commingling of production downhole, accurate determination of contribution from each zone

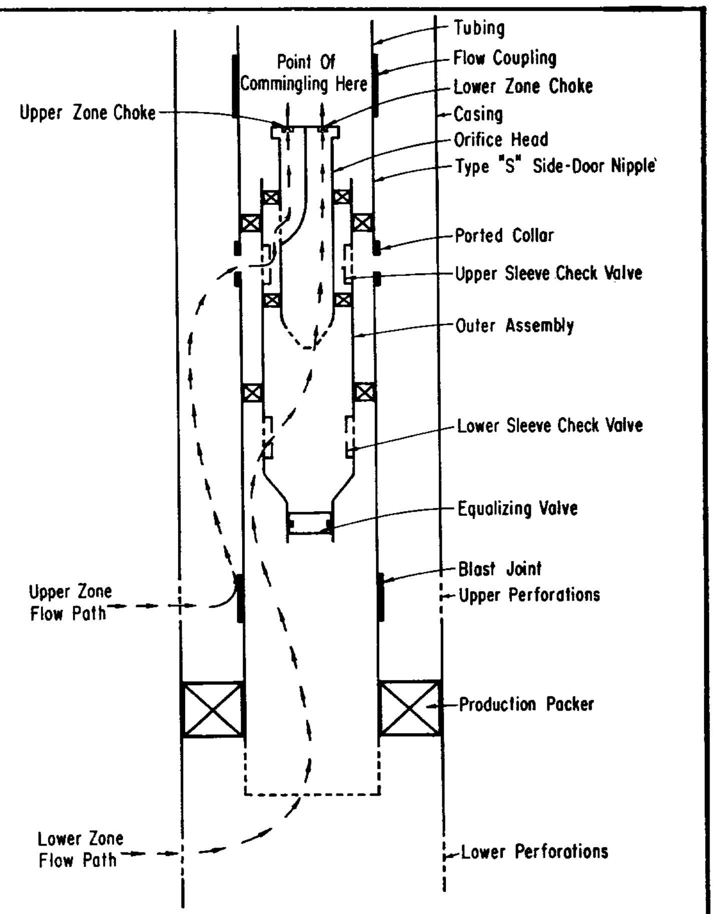

FIGURE 1—Schematic drawing shows how new multiple completion wireline tool works. Note that production is effectively separated until commingled above chokes.

By J. W. Hodges, Administrative Engineer,
Sun Oil Company, Beaumont, Texas

Sun Oil Company has developed and is currently using a new wireline multiple completion tool to produce two separate reservoirs simultaneously through a single tubing string. The multiple completion tool has been successfully installed in a well in Allen Parish, Louisiana since March 1960. Annual gross income from the well has increased $48,400.00, with a net reduction in operating costs. Another tool was set recently in a well in St. Mary Parish. Five additional Sun installations in Louisiana are in progress.

Major advantages in using this tool to commingle production from separate reservoirs in one string of tubing are:

- Excess energy from one zone can be used to lift production from a weaker well.
- Current income can be increased and well costs reduced sharply.
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- When completed and commingled with a good well, weak zones can be produced to depletion without artificial lift.

All these factors contribute to an increase in ultimate recovery.

Operation of the downhole commingling tool is shown schematically in Figure 1. The lower zone flows up the tubing, enters the tool through a slotted section in the outer assembly, flows around a resilient check valve and enters the tube of the orifice head assembly where it is choked. Lower zone production then is commingled with upper zone fluid in the tubing above the tool.

The upper zone flows up the casing and into the tubing through a ported collar. It then enters the tool through another slotted section in the outer assembly, flows around the upper resilient check valve into the annulus around the tube, is choked and then commingled with the lower zone.

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The multiple completion choke assembly is shown in Figure 3. The outer assembly, shown on the left, is run with wireline tools and is located and locked in a type S side-door choke landing nipple. The resilient check valves, shown opposite the relative positions they occupy within the tool, prevent flow from one zone to the other. The orifice head, shown on

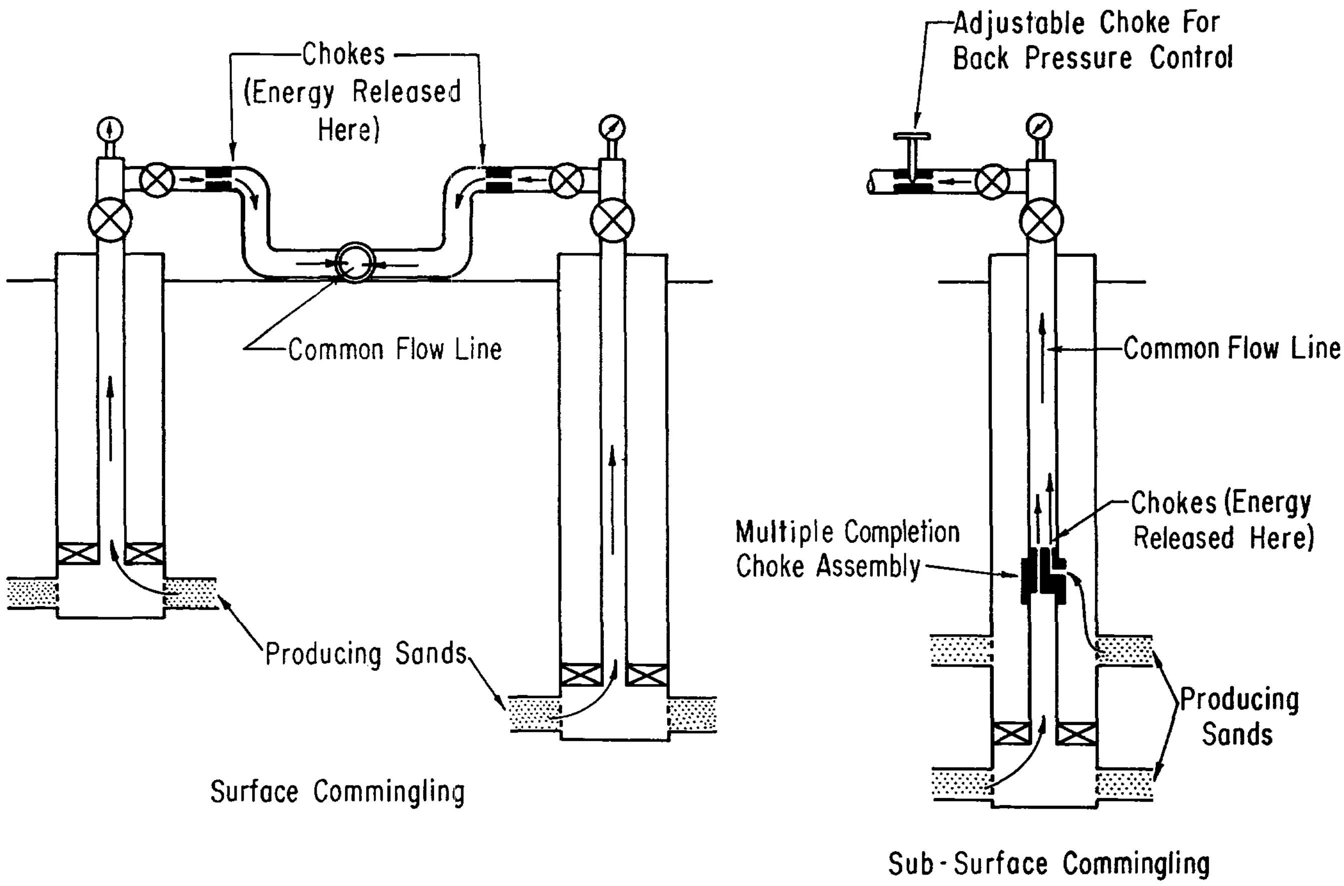

FIGURE 2—Downhole commingling is analoguous to surface commingling except that the pressure reduction is accomplished at the bottom of the hole where energy in released gas can be used.

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Steps involved in installation of the assembly are illustrated in Figure 4. When a choke change is required, the orifice head is pulled leaving the outer assembly in place. The check valves in the outer assembly prevent flow from one zone to the other even with the orifice head removed from the well. Required wireline operations are relatively simple and have become routine.

The well in Allen Parish, prior to installation of the multiple completion choke assembly, was producing as a concentric dual completion with the upper zone flowing in the annulus between the 2⅜-inch tubing and 5½-inch casing and the lower zone flowing through the tubing. The upper zone, a high ratio oil well, is completed through perforations 8,067-70 feet. The lower zone, a gas well, is completed through perforations 8,448-52 feet. The conversion to commingled flow was made with wireline tools by pulling the side-door choke located at 8,000 feet and replacing it with the multiple completion choke assembly.

The subsequent increase in production resulted from decreased gas-liquid ratios and an increase in lower zone productivity. Operating costs were reduced through elimination of the surface heater (by the bottom hole choke effect) and because gas from the lower zone no longer requires compression to enter the sales line. Periodic production and packer leakage tests required by the Louisiana Department of Conservation have been performed on a routine basis. *There has been no evidence of communication between the two reservoirs.*

Hardness of the choke material and location of chokes below paraffin deposition depth have eliminated choke erosion and plugging. This has resulted in accurate determination of the contribution from each zone. Table 1 reflects the consistency of production rates through the $\frac{5}{64}$-inch choke serving the upper zone well. The same $\frac{5}{64}$-inch choke was used in each test and operated in the well from April 1, 1960 until replaced with a different size choke in January 1961. The choke was not cut when replaced.

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Conditions imposed by use of the multiple completion choke assembly afford maximum opportunity for accurate flow rate control. In any system involving commingled production, the accuracy of determining the contribution from each zone depends on accurate flow rate control. The chokes in the multiple completion tool —more resistant to erosion and unaffected by paraffin deposition—will perform more efficiently than surface chokes. The multiple completion tool dual, therefore, will provide for more accurate allocation than can be obtained with conventional surface commingling.

Multiple completion choke beans are undergoing a severe abrasion test in one of Sun's wells in Chambers County, Texas. In an attempt to solve acute problems associated with high pressure well completions, the multiple completion tool has been modified to single zone flow and is being used as a bottom hole choke. Surface tubing pressure of this well has been reduced from 7,300 psi to 4,100 psi.

A high differential type leak, probably a tubing thread leak, which had existed before the installation was made, has been stopped. Production through the choke to date has been 492,000 Mcf of gas and 2,400 barrels of condensate, a total effluent in excess of 24 million pounds. There has been no discernible cutting of the choke.

If this experiment proves the feasibility of pressure reduction as a solution to the problems associated with producing abnormally high pressure wells, hazards to personnel will be reduced and the terrific costs incurred in working over such wells can be avoided.

The dual oil well in St. Mary Parish, an inland water location, is completed 14,236-39-feet and 14,025-33-feet. A drill stem test of the upper sand completion indicated productivity too low to justify the additional cost of a twin string dual. Production tubing was run with a single packer, a side-door choke landing nipple, and a side-door choke.

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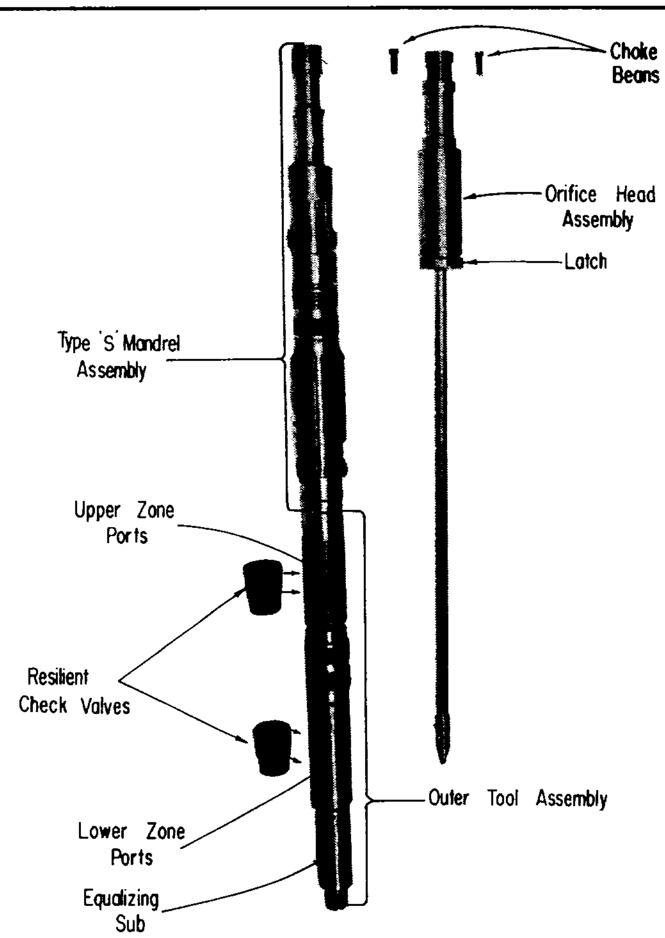

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The necessary wire line operations in this deep, high pressure, high temperature, directional well have been performed with relative ease; however, a word of caution is directed to anyone planning to use this tool for the first time: someone with previous experience should be on the job. Dressing and running the assembly would not be a routine operation to an inexperienced person and could jeopardize success of the installation.

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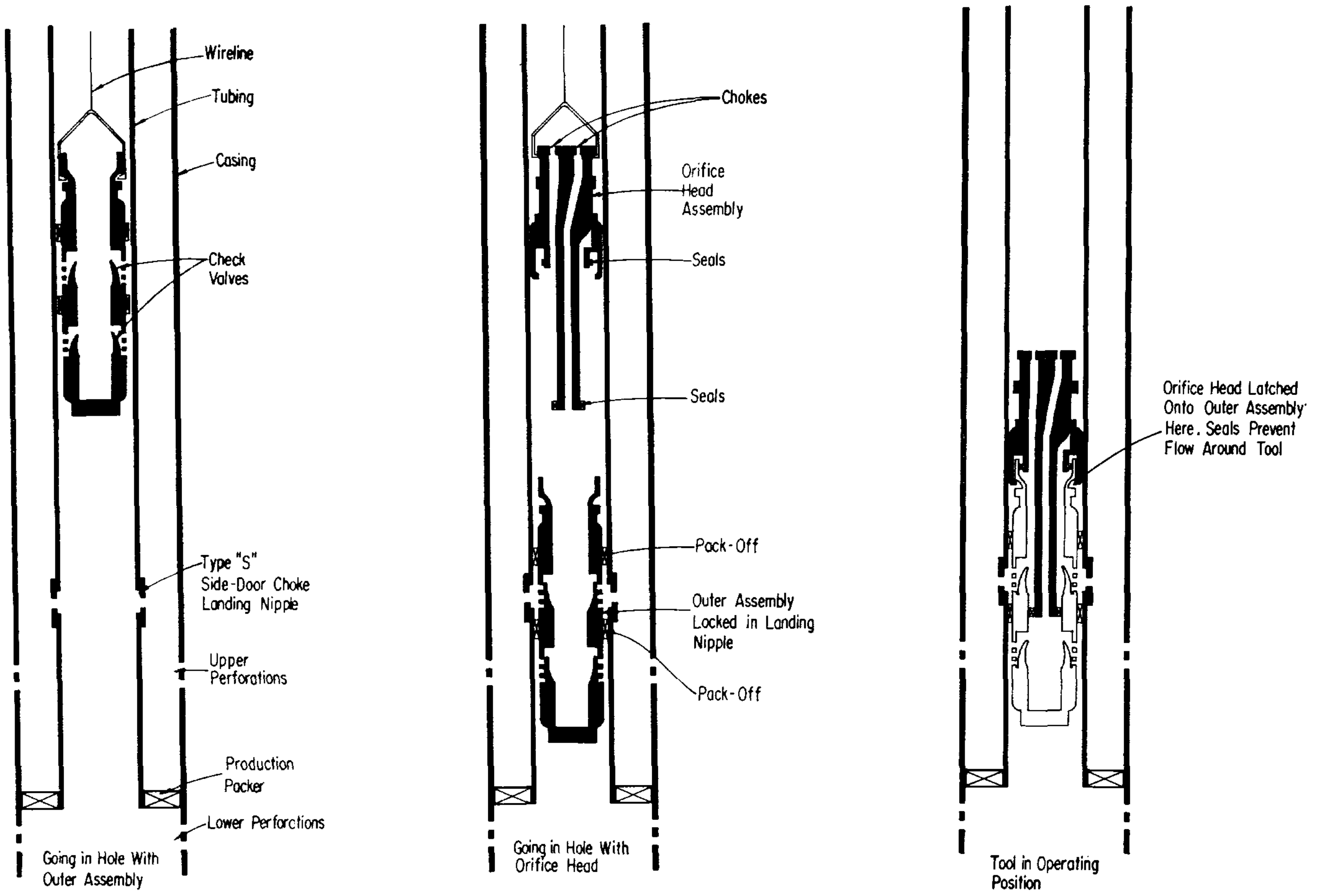

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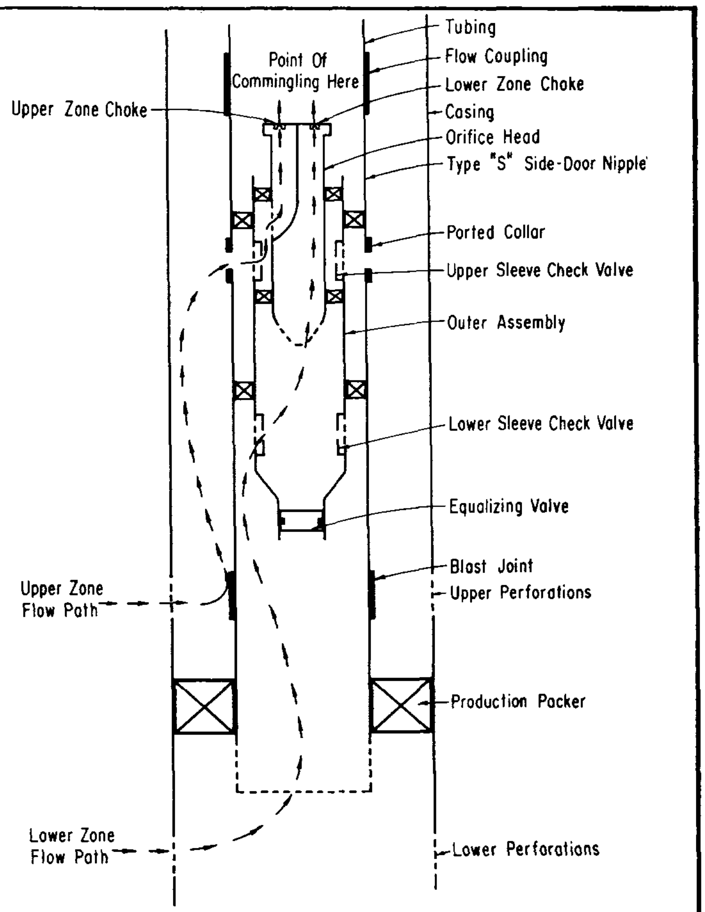

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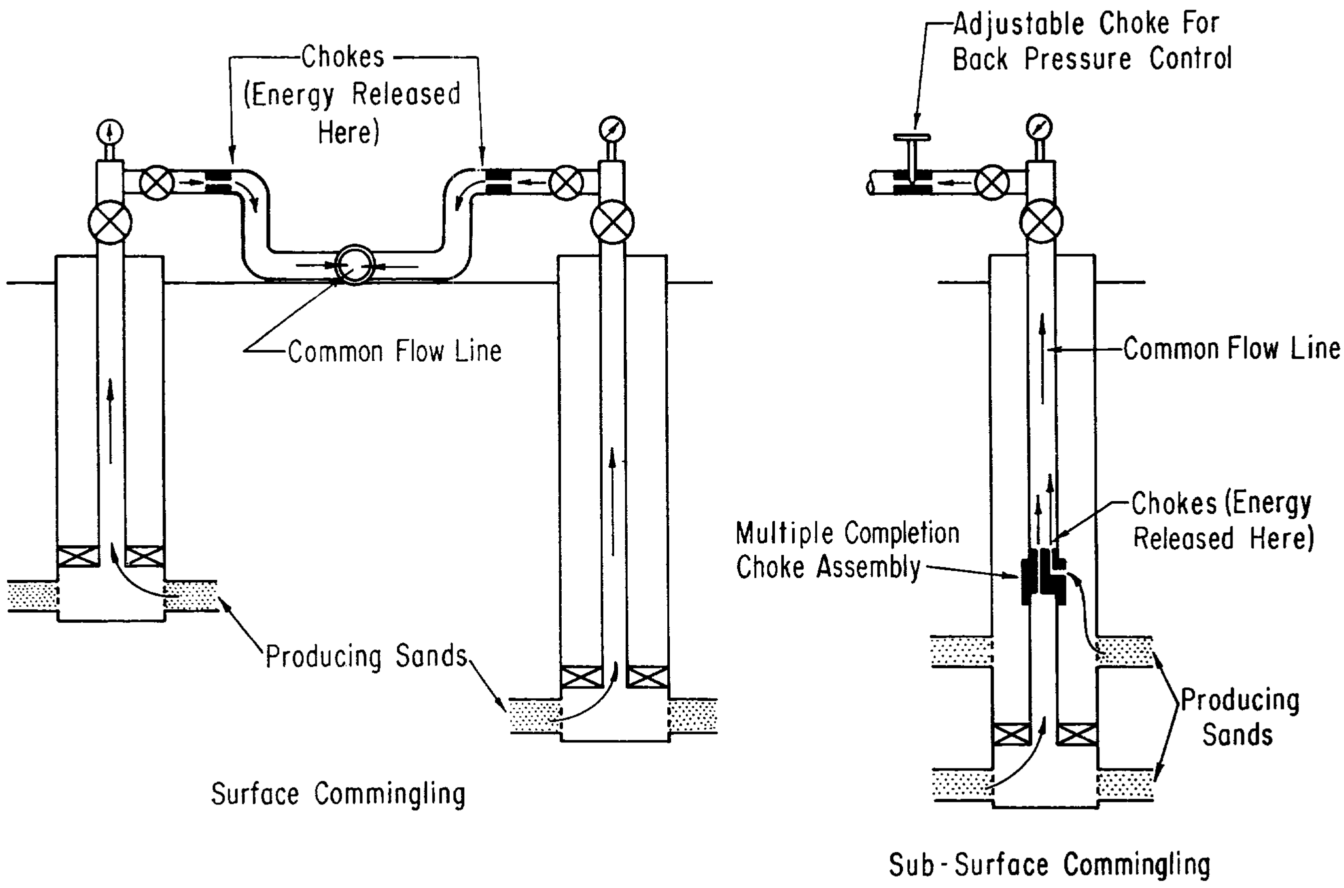

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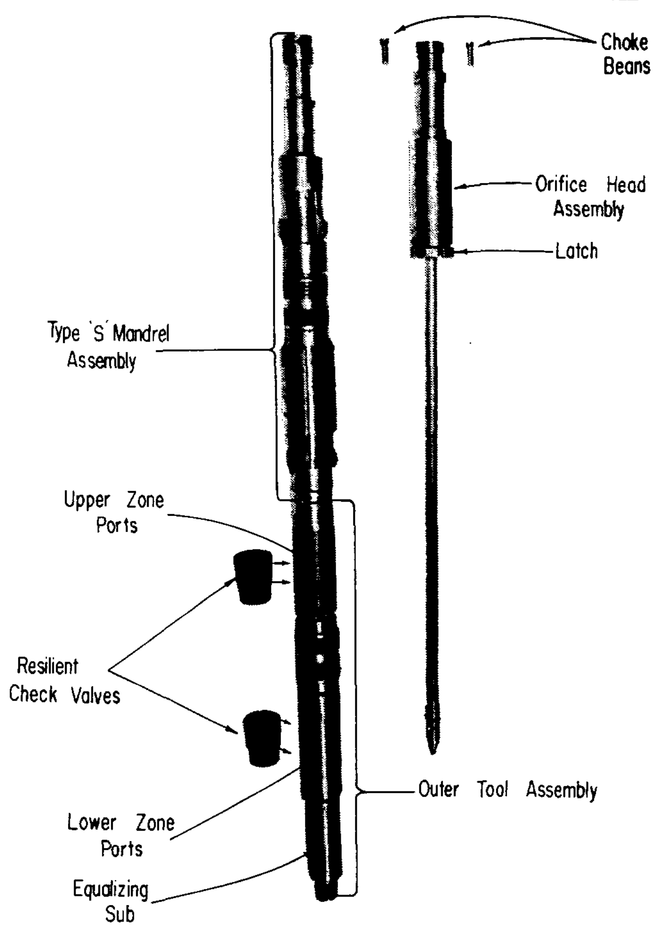

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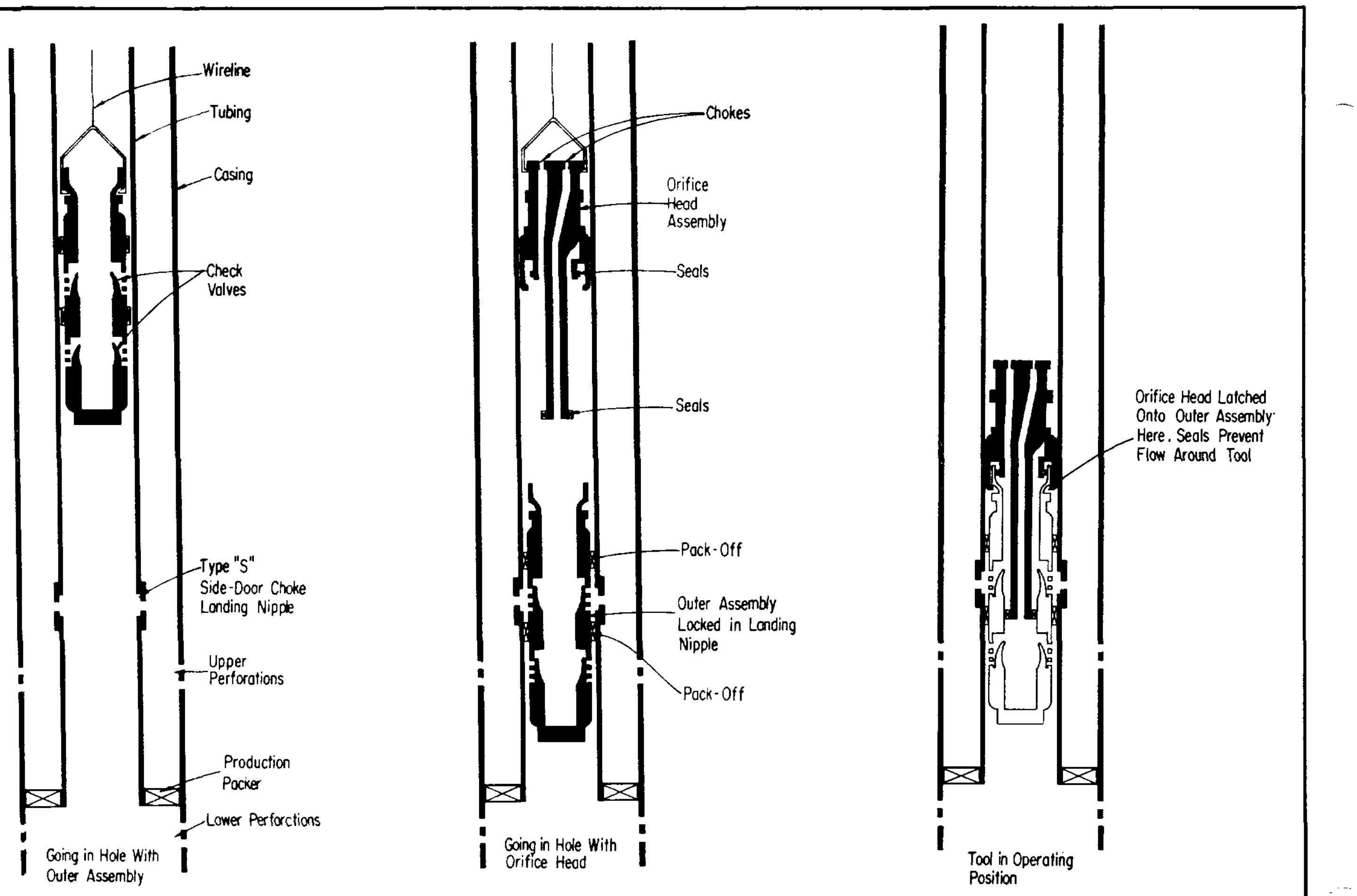

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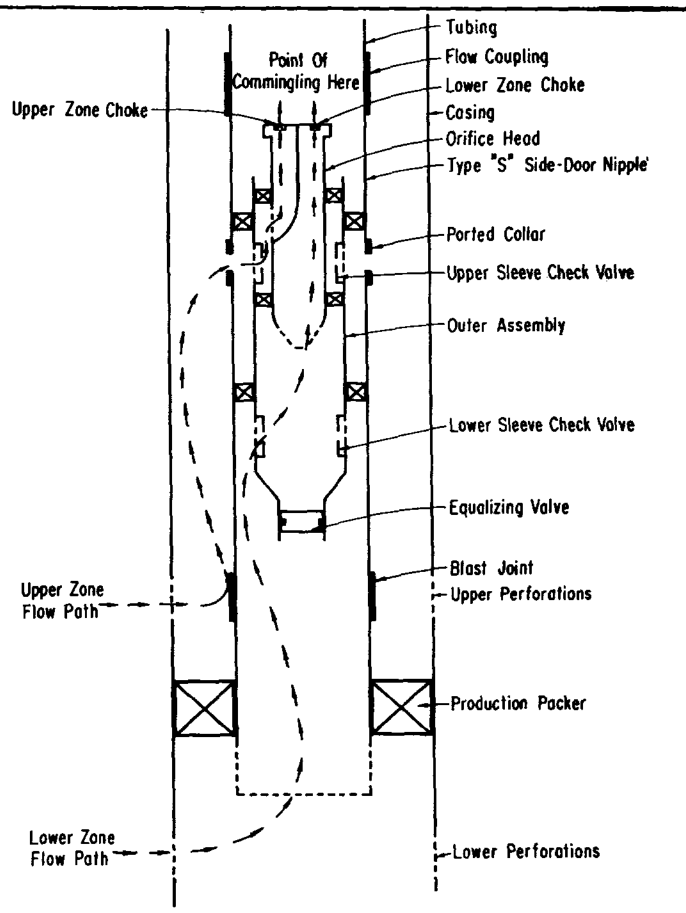

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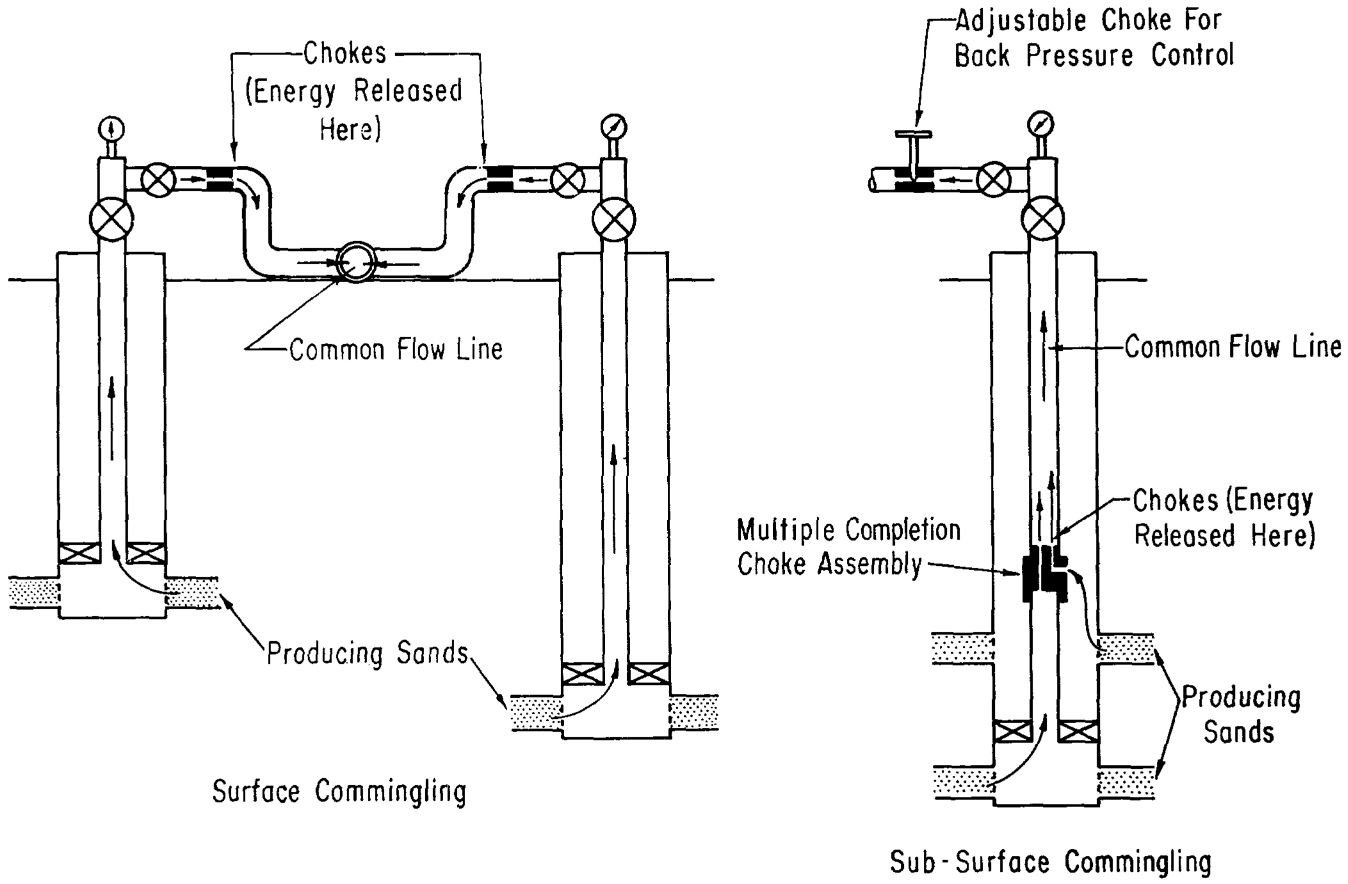

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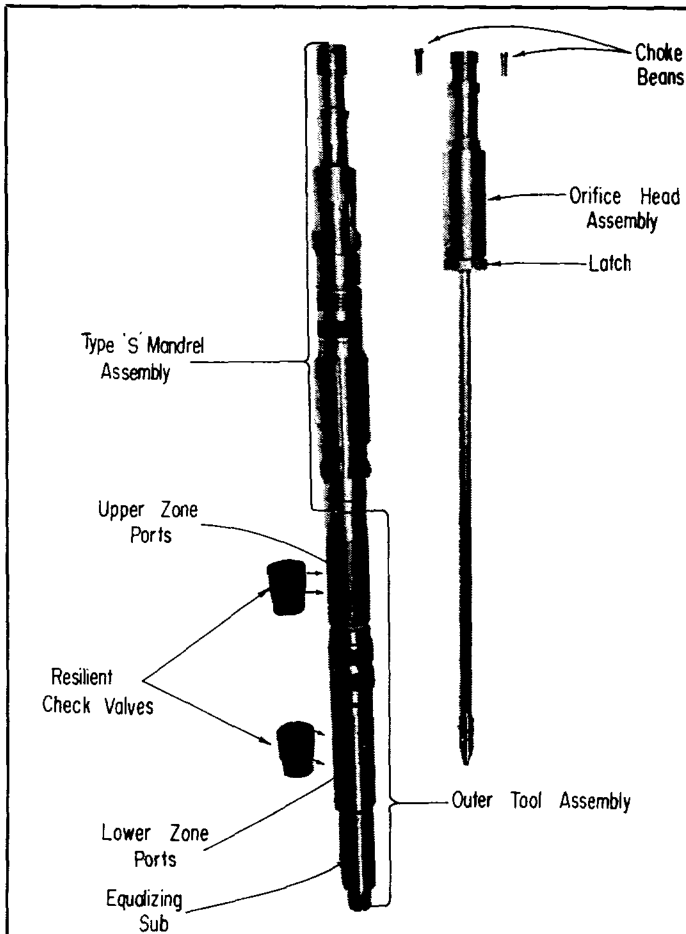

FIGURE 3—Elements of multiple completion tool are shown here. Orifice head assembly can be retrieved separately to blank off one choke for well test purposes or to change production chokes.

The dual oil well in St. Mary Parish, an inland water location, is completed 14,-236-39-feet and 14,025-33-feet. A drill stem test of the upper sand completion indicated productivity too low to justify the additional cost of a twin string dual. Production tubing was run with a single packer, a side-door choke landing nipple, and a side-door choke.

The side-door choke was removed after displacing drilling mud, and the multiple completion choke assembly was installed in its place. Testing now is in progress to establish potential of the two zones.

The flowing bottom hole pressure of the lower zone is reduced from 6,500 psi to 1,350 psi across the tool. Surface pressure is regulated at 150 psi and can be increased with an adjustable choke, if necessary, to control upper zone production. Tubing pressure immediately above the multiple completion tool can be elevated to approximately 3,250 psi without changing the lower zone rate.

The necessary wire line operations in this deep, high pressure, high temperature, directional well have been performed with relative ease; however, a word of caution is directed to anyone planning to use this tool for the first time: someone with previous experience should be on the job. Dressing and running the assembly would not be a routine operation to an inexperienced person and could jeopardize success of the installation.

The multiple completion tool can be used in a wide range of wells: dual oil; dual oil and gas; dual gas (the tool is ideally adapted to dual gas wells and is being used in that capacity in Mexico); permanent completions; and gas lift installations.

To determine whether the tool has application in any particular well, one must first determine the pressure that will exist at the point of commingling. This will be the controlled surface pressure plus the pressure required to lift the combined fluids to the surface, the latter being essentially a function of gas-liquid ratio,

TABLE 1—Test Results of Upper Well With Lower Well Blanked Off

TEST DATE	Choke Size	Oil-BPD	Gas-Mcfd	GOR
7-24-60	5/64"	7.23	248	34,200
10- 5-60	5/64"	7.80	227	29,100
10-18-60	5/64"	7.80	227	29,100
12- 4-60	5/64"	7.23	209	28,900
1-27-61	3.5/64"	6.38	175	27,500

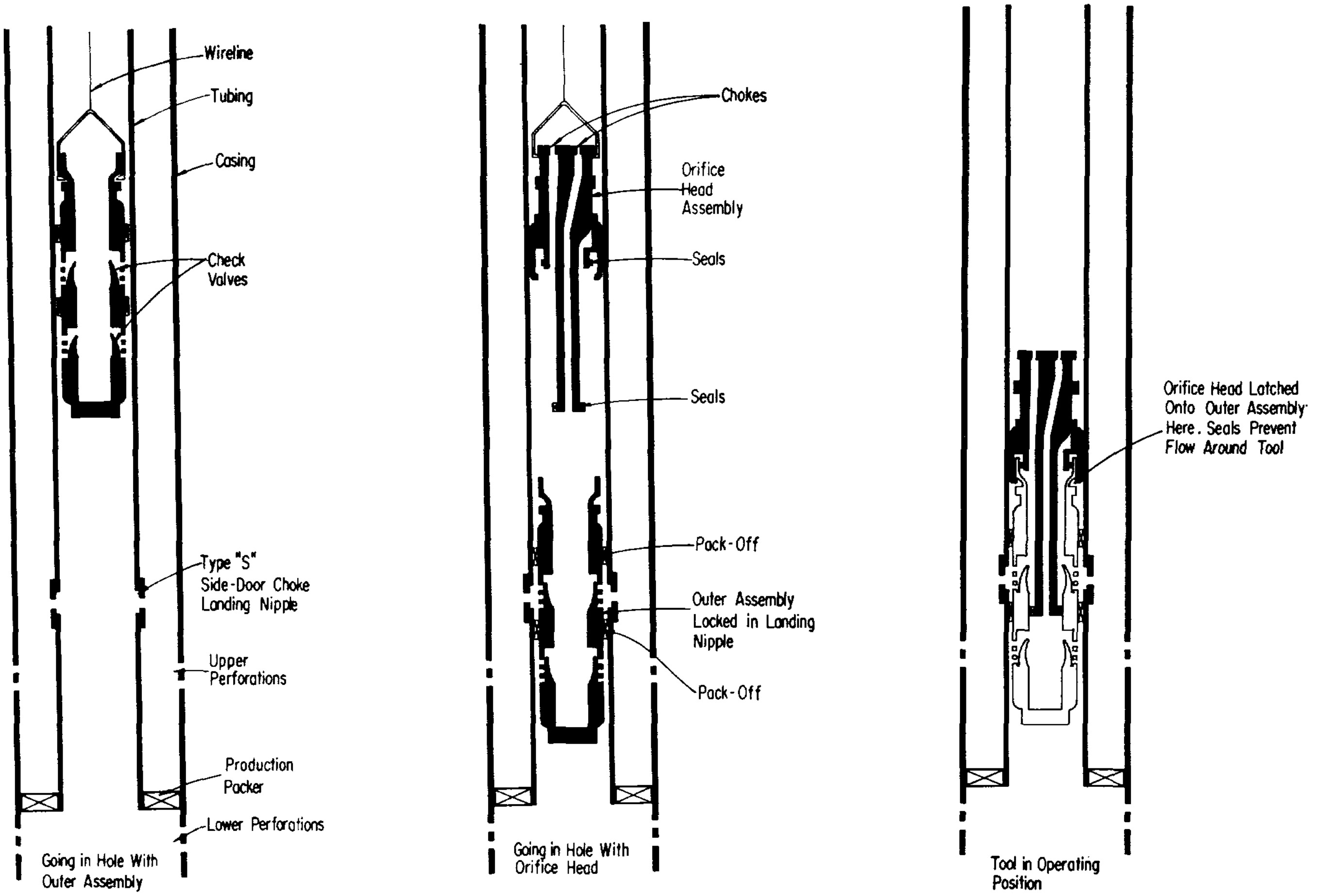

FIGURE 4—Inner and outer assemblies are run separately as shown. Note in center drawing that resilient check valves in outer assembly prevent interzone flow.

production rate and tubing size. Published flowing gradient curves covering almost any set of conditions now are available and can be used for this purpose. Pressure at the point of commingling and productivity index of the weaker well will determine its maximum rate of production.

Use of the multiple completion tool as a gas lift mechanism offers interesting possibilities. When gas direct from the formation is used to lift liquids through the tool, the gas is put to work at maximum depth and pressure thus obtaining maximum efficiency. Single point injection with a retrievable flow valve, considered by many to be the ultimate in gas lift, can be attained with the multiple completion tool.

Field tests of the multiple completion tool have demonstrated it to be a means of increasing current income as well as ultimate recovery at reduced operating costs. This should appeal to all segments of the industry —oil companies, royalty owners and regulatory agencies.

Future development of the multiple completion tool depends to a large extent on acceptance by conservation commissions, as well as the oil industry. Acceptance in turn depends on a thorough understanding of the tool and an appreciation of its potential worth. Some traditional ideas and concepts must be re-examined. There is a great difference between controlled and uncontrolled subsurface commingling. Sun has clearly demonstrated in field tests that wireline tools can be used to separate the production from two reservoirs, to control the rate of production from each and to change the rate of production as required.

The interest and cooperation shown by the Louisiana Department of Conservation has been a material factor in the present stage of development of this new production technique.

About the Author

J. W. Hodges received a B.S. degree in petroleum engineering from The University of Texas in 1938. He joined Sun Oil Company upon graduation and has worked as seismographer, roustabout, roughneck, pumper, drilling engineer, production engineer, field superintendent, division petroleum engineer and administrative engineer, his present position. He holds several patents on oil field tools and has several pending, including one on the multiple completion tool discussed in this article.

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New Tool Permits Simultaneous Production of Two Reservoirs Through the Same Flow String

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Abstract

The constant search for methods to increase the efficiency of production systems and to reduce operating costs has led to the development of a wireline tool which makes it possible to produce and control two separate reservoirs through a single string of tubing. This paper is a progress report of the experience one company has gained with this tool in eight of its dually completed wells in Louisiana and Texas. Field tests have clearly demonstrated that this device can be used to maintain separation of production from two reservoirs, to control and determine the rate of production from each, and to change the rate of production as required. The advantages in simultaneous one-string multiple completions are enumerated, and various applications of the method are discussed.

Introduction

It is now almost standard operating procedure to complete wells in more than one zone wherever possible, with the great majority of these multiples being dual completions. This is a sign of the times. Saving must be accomplished wherever possible; however, there is no need to expand on this theme. All are painfully aware of the economic conditions within the industry. It is sufficient to say that the practice of multiple completions is here to stay and is becoming more popular every day. The only question is whether or not the practice has evolved into its most acceptable form.

The earlier duals were the concentric type, with one zone producing through the tubing and the other through the tubing-casing annulus. This method is still practiced to a large degree. It is popular because it is relatively inexpensive. Unfortunately, it has some rather severe limitations, with which the reader undoubtedly is familiar.

The twin-string dual is an improvement over the concentric in the sense that many of the problems associated with the concentric have been solved. The objectionable features of the twin-string dual are the high cost of equipping the well with an extra string of tubing, plus accessories, and the complications brought on by cramming all this tubing into one string of casing.

Still another type of multiple is the tubingless completion, wherein two or more small casing strings are cemented in place and subsequent operations performed with miniaturized equipment.

The purpose of this paper is to present a different concept in multiple completion—the simultaneous production of separate reservoirs in a single flow string. This method combines the simplicity and low cost of the concentric with the flexibility of the twin-string dual. In addition, it provides the unique advantage of prolonging natural flow from a low-pressure zone by combining its production with the fluids produced from a higher-pressure zone. The wireline tool which makes this method possible is the multiple-completion choke assembly.

Construction and Operation of the Multiple-Completion Choke Assembly

Fig. 1 shows a well properly equipped to receive a multiple-completion choke assembly. A conventional packer separates the two producing zones. The upper packer is optional. A side-door choke landing-nipple hookup is located in the tubing

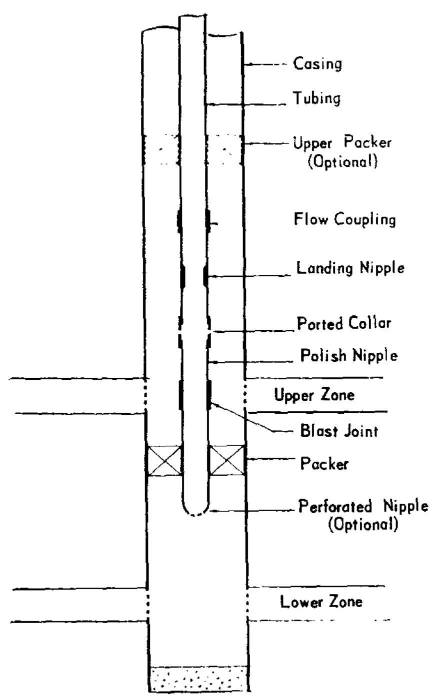

Fig. 1—Well properly equipped for multiple-completion choke assembly.

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string above the lower packer. The multiple-completion choke assembly will be locked in this landing nipple. Normally located a joint or two above the upper zone, the position of the landing-nipple hookup can be varied to suit well conditions. For example, where the two zones are widely separated, it might be placed just above the lower packer to facilitate bottom-hole pressure tests of the lower zone.

The tool consists of two separate assemblies. The outer assembly, which is run independently and locked in the landing nipple, contains the check valves and packing seals which prevent flow from one zone to the other. In practice, however, only one check valve is usually required and is installed to protect the zone with the lower pressure.

The orifice-head assembly, which carries the tungsten-carbide choke beans, is run separately and is seated and locked in the outer assembly. The method of running each section is illustrated in Fig. 2.

Fig. 3 is a schematic drawing which shows more clearly how the device works. Production from the lower zone enters the assembly through a slotted section, flows around a resilient sleeve-type check valve, enters, and flows through the tube of the orifice-head assembly; it is choked and—now regulated—flows into the tubing. Produced fluids from the upper zone enter the casing opposite a blast joint on the tubing, flow through the ported collar of the side-door choke landing-nipple hookup, through the upper slotted secion, around the upper check valve, into the annulus surrounding the tube and through the upper-zone choke bean into the tubing. Here the two controlled flow streams, which have been kept separate up to this point, combine and flow to the surface.

Tubing Inlet Pressure

The pressure in the tubing at the junction of the two streams will be the minimum pressure required to lift the combined fluids to the surface (at zero surface pressure) and will be determined essentially by the gas-liquid ratio, production rate and tubing size. This pressure, which will hereafter be referred to as the "tubing inlet pressure", is of particular interest because of its importance in the application of the multiple-completion choke assembly. For example, suppose that investigation is being made into the possibility of using the assembly in a two-zone oil well with characteristics as tabulated in Table 1.

The combined production rate is 160 B/D of liquid (including salt water) and 87 Mcf/D of gas. The combined gas-liquid ratio is 543 cu ft/bbl. With a multiple-completion choke assembly set at 6,500 ft in 2⅜-in. OD tubing, it can be determined from published depth-pressure gradient curves[1] that the tubing inlet pressure will be approximately 850 psi.

The upper zone, with a productivity index of 0.5, will produce 96 B/D of liquid with a flowing bottom-hole pressure of approximately 1,308 psi. Since the flowing bottom-hole pressure of the weaker zone is greater than the tubing inlet pressure at the desired rate of production, this well can be produced by natural flow with a multiple-completion choke assembly. Natural flow will be maintained so long as the flowing bottom-hole pressure of the weaker zone (in this example, the upper zone) exceeds the tubing inlet pressure. At some point in the life of the upper zone, however, conditions favorable for natural flow *as a single completion* would no longer prevail. In other words, if it were being produced independently, some form of artificial lift would be required. The requirement is postponed because of the availability of the gas from the lower zone. When the lower zone can no longer "carry" the upper, a single set of flow valves can be run to produce both zones through the multiple-completion choke assembly.

TABLE 1—WELL DATA USED IN EVALUATING APPLICATION OF MULTIPLE-COMPLETION TOOL

	Upper Zone	Lower Zone
Producing Depths (ft)	6,600	7,200
Static BHP (psi)	1,500	3,400
Productivity Index (B/D/psi drop)	0.5	1.0
Oil Produced (B/D)	56	64
Salt Water Produced (B/D)	40	None
Gas Produced (Mcf/D)	39	48
Gas-Liquid Ratio	406	750

Allocation of Production

Allocation of fluids produced from each zone is based on a separate, individual zone test. To obtain such a test, the orifice-head assembly is removed from the check-valve assembly and brought to the surface with conventional wireline tools. (Removal of

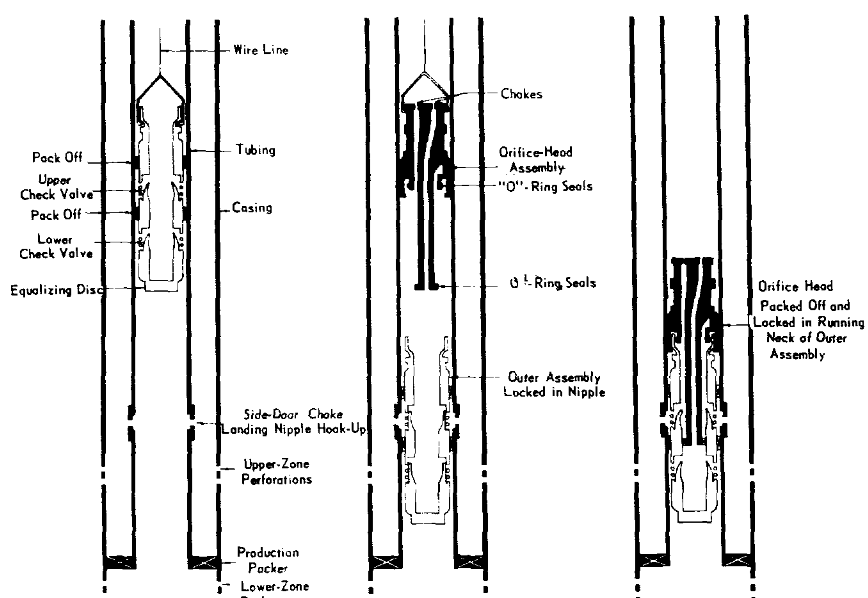

Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

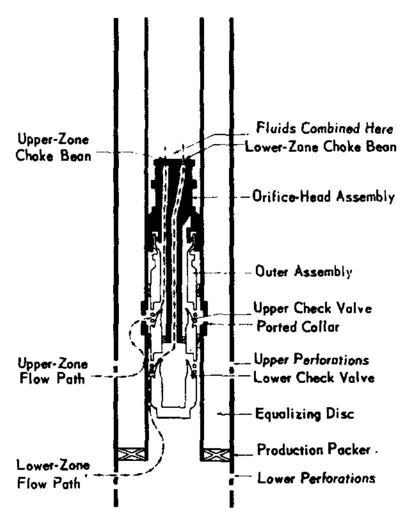

Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

the orifice head does not result in interzone flow, as the check-valve assembly remains in the well.) If the lower zone is to be tested, a blank bean is inserted in the opening in the orifice head communicating with the flow path of the upper zone. A choke bean, properly sized[1] to produce the desired volume of fluid from the lower zone, is placed in the opposite side of the orifice head. The orifice head is then lowered into the well, and landed and locked in the check-valve assembly. The upper zone cannot flow because of the blank choke bean. Produced fluids from the lower zone are measured into conventional surface facilities until a stabilized 24-hour test is obtained. The orifice head is again removed from the well. The blank bean is replaced with a production bean, and the assembly is returned to its operating position in the well. A stabilized test of the combined fluids produced is obtained. The predetermined rate from the lower zone is subtracted from the combined total, with the difference assigned to the upper zone.

The test procedure used will be determined by the flow conditions present in the well—specifically, whether or not one of the zones is in critical flow. A stream is said to be in critical flow when alterations in pressure downstream from an orifice do not affect the rate of flow through the orifice. The critical point occurs when the downstream pressure is 53 per cent of the upstream pressure. The significance of this phenomenon in the operation of the multiple-completion choke assembly is that, if one of the zones is in critical flow and the other is not, the zone not in critical flow can be regulated with a surface control without affecting the rate from the other. In the well described earlier, for example, if the tubing inlet pressure is not allowed to exceed approximately 1,765 psi (53 per cent of 3,336 psi), the rate from the lower zone will not be affected. In other words, back-pressure at the surface can be increased to the point of actually shutting-in the upper zone, with no effect on the rate from the lower zone.

In any well where two reservoirs are being produced simultaneously through the multiple-completion choke assembly, one of the following three conditions will exist: (1) one zone will be in critical flow; (2) neither zone will be in critical flow; or (3) both zones will be in critical flow. The method of testing for allocation will depend upon which one of these conditions exists.

The exact value of the critical P_2/P_1 ratio, whether it be 53 per cent or some other value, is of no particular concern. The ratio is not used quantitatively. As a matter of interest, however, in the wells where this critical point has been observed, the value has appeared reasonably close to 53 per cent.

The exact point of critical flow can be determined by changing the surface tubing pressure with an adjustable choke, measuring the rate of flow into conventional test facilities and observing the effect of the back-pressure changes.

At the same time, the tubing inlet pressure is measured with a bottom-hole pressure gauge. For example, tests run on a certain zone in a dual completion might result in the data shown in Table 2.

These data show the stream is going into critical flow between a tubing inlet pressure of 1,050 and 825 psi. This point can be determined more precisely if the results are shown graphically, as will be illustrated later in actual well tests.

A predetermined rate for this particular zone on a specific choke size for this range of tubing inlet pressures has now been established. It makes no difference what effect, if any, the second zone may have on the tubing inlet pressure in the well. Because this pressure can be determined, the rate from the first zone will be known. The difference is then assigned to the zone not tested individually, usually the lower-pressure zone.

If each zone can produce its allowable independently of the other, there may be some reason to test each separately. This procedure, of course, will require additional wireline work and is not essential in determining the production from each zone. The method has been used occasionally to demonstrate the consistency of flow-rate control possible with the choke beans in the tool.

Summarizing, production tests will follow one of two patterns. If either or both of the two zones is in critical flow when combined, a 24-hour stabilized test of the zone with the higher pressure is obtained. Back-pressure is not adjusted during this test. Following this, both zones are combined and tested for 24 hours at a stabilized rate. The difference in production is known to have come from the zone not tested singly.

If neither of the zones is in critical flow, the zone with the higher pressure is tested individually. The surface pressure is varied and the stabilized rates of production at the various back-pressures are measured. Tubing inlet pressure is recorded with a bottom-hole pressure gauge. This test predetermines the rate to be expected from this zone during periods of combined flow. The rate from the other zone will be determined by difference.

TABLE 2—CRITICAL FLOW DATA

Surface Tubing Pressure (psi)	Tubing Inlet Pressure (psi)	Liquid Rate (B/D)
700	1,300	50
500	1,050	55
300	825	60
100	600	60

Use Of The Tool In Gas Lifting

The multiple-completion choke assembly, when used as a gas-lift device, is in effect a single-point injection, retrievable flow valve utilizing gas supplied directly from the formation at maximum efficiency. An expert in gas-lift technology, in discussing conventional gas-lift systems,[2] has made the following pertinent observations.

> Which flow process, continuous or intermittent, will yield the greatest amount of produced stock-tank liquid for the least amount of injected gas at the available pressures? The continuous-flow process, if properly instituted, should be inherently more efficient than that of intermittent flow. The gas is put to work as needed and the high dissipation of initial energy in overcoming starting inertia is largely absent. Also, the external work done by the gas is negligible. The fact is, however, that maximum efficiency in the continuous-flow process can only be realized by putting the gas to work as soon as possible. This means high injection pressures at moderate depths. Because the high injection pressures necessary for maximum efficiency are seldom available, it has been found in practice that the intermittent-flow process is frequently more efficient than that of continuous flow, for wells that produce moderate amounts of liquid.
>
> It is significant to point out here that the Phillips paper, previously referred to, lists data from some 34 flowing wells and 16 gas-lift wells (continuous flow). The thermodynamic flow efficiency for the flowing wells was on the order of 85 to 95 per cent, whereas the gas-lift wells were mainly of the order of 40-60 per cent. There is no reason why continuous-flow gas-lift wells should not closely approximate the efficiency of naturally flowing wells, if the installations are correctly designed.
>
> It is recognized that the high-pressure requirements for maximum efficient operations is definitely a limiting factor in any practical well installation. It is most important to recognize that, as injection pressures are decreased below the optimum, the flow efficiency

[1]References given at end of paper.

of the installation falls off very rapidly.

Low injection pressures mean high injection GORs and should be avoided where possible.

. . . and to emphasize the advantage of valve installations in which the valves may be retrieved and reset or replaced.

These statements make a strong case for using the multiple-completion choke assembly as a gas-lift mechanism. The high injection pressures necessary for maximum efficiency are now within practical reach. Almost any well can be produced by continuous lift. The "flow valve" can be removed and replaced by wireline. All this adds up to maximum efficiency at minimum cost.

To illustrate the truly significant potential of the multiple-completion choke assembly as it applies to gas lift, a comparison was made between gas lifting with a conventional system and with the multiple-completion choke assembly in a well in the Sour Lake field, Hardin County, Tex. The Railroad Commission of Texas has granted permission to use in this well a gas sand at 9,610 ft to supply gas-lift gas through the multiple-completion choke assembly to lift produced fluids from an oil sand at 9,800 ft. The results of this study[3] were rather startling. The input gas required using the conventional system was calculated to be 560 Mcf/D as compared to only 34 Mcf/D using the multiple-completion choke assembly; in addition, it should be remembered that the latter method does not require surface gas-lift facilities such as high-pressure separators or compressors, heaters, dehydration equipment, delivery lines, etc.

Data pertinent to the analysis and the results thereof are presented in Table 3.

Field Tests

Sun Oil Co.'s first test of the multiple-completion choke assembly was in the Kinder field, Allen Parish, La., in Sept., 1959.

Additional development and testing were done in the North Winnie field in a surface manifold with a high-pressure oil well flowing through the tool. Sand-laden liquid was pumped into the flow stream where it entered the manifold. The severity of these and other surface and subsurface tests has resulted in the development of a very durable and rugged tool.

TABLE 3—GAS-LIFTING WITH MULTIPLE-COMPLETION TOOL COMPARED TO CONVENTIONAL METHOD

Conditions	
Required Production (B/D)	100 oil, 100 SW
Productivity Index (B/D/psi drop)	0.154
Surface Pressure (psi)	100
Static BHP Lower Zone (psi)	3,800
Static BHP Upper Zone (psi)	4,000
Gas-Oil Ratio Lower Zone (cu ft/bbl)	500
Gas-Liquid Ratio Lower Zone (cu ft/bbl)	250
Required Gas-Liquid Ratio for Well to Flow (cu ft/bbl)	420
Input Gas Pressure (psi)	*700*

Comparison Between the Two Methods

	Conventional	Proposed
Number of Flow Valves	11	1
Depth of Lift (ft)	4,500	9,500
Input Gas-Liquid Ratio (cu ft/bbl)	2,800	170 (420-250)
Gas Required (Mcf/D)	560	34

Well No. 1

The first successful field test was begun March 31, 1960, in a well in the Kinder field. The Louisiana Conservation Commission approved a six-month test period and, after a three-month interval, granted permanent approval to use the tool in this well, which will be identified as Well No. 1.

Sun now has eight wells equipped with multiple-completion choke assemblies, and several more installations either are planned or are in progress. A description of the wells now equipped with the assembly appears in Table 4.

Well 1, prior to installation of the multiple-completion choke assembly, was a concentric-type dual completion with the upper zone flowing in the annulus between 2⅜-in. tubing and 5½-in. casing and the lower zone flowing through the 2⅜-in. tubing. As a result of using the tool, the combined hydrocarbon production from the two zones was increased by approximately 20 B/D and 300 Mcf/D, representing an annual increase in gross income of $48,400.

Tables 5 and 6 illustrate the exact method used to allocate production from the two zones in Well 1. Table 5 represents four consecutive 24-hour tests of stabilized flow from the upper zone with the lower zone closed in by a blank choke bean in the orifice head. It is not necessary, as a routine matter, to run the tests this long. The tool was experimental during this period, and the stabilized nature of the flow possible with the device was being demonstrated. Table 6 represents tests made of the combined flow, with the resulting allocation to each zone.

Table 7 shows the results obtained during the following months when testing the upper zone individually, and demonstrates the accurate flow-rate control possible with the choke beans used in the assembly. The same 5/64-in. choke was used throughout the period shown. Gas production was measured by orifice meter and liquid production was gauged in a 210-bbl tank.

TABLE 4—DESCRIPTION OF WELLS USING MULTIPLE COMPLETION TOOL

Well No.	Location	Depth (ft)	Static BHP (psi)	Production (B/D)	Gas-Liquid Ratio (cu ft/bbl)
1	Kinder, La.	8,067	2,575	6 Oil	22,100
		8,448	2,460	19 Cond.	18,466
2	Bayou Sale, La.	14,025	5,870	20 Oil	1,000
		14,236	6,533	75 Oil, 75 SW	7,750
3	Kinder, La.	7,678	3,263	64 Oil	784
		8,379	3,371	37 Cond.	19,100
4	Belle Isle, La.	13,958	6,500	129 Oil	735
		13,983	6,500	129 Oil	945
5	Kinder, La.	7,394	3,290	7 Oil, 15 SW	643
		8,390	0,485	64 Cond.	16,188
6	Belle Isle, La.	12,840	5,670	115 Oil	906
		13,398	5,781	129 Oil	423
7	Bateman Lake, La.	10,154	4,538	71 Oil	2,929
		11,700	5,060	65 Oil, 10 SW	3,354
8	Sour Lake, Tex.	4,710	814	No Cond., No SW	113 Mcf Dry Gas
		4,788	1,093	14 Oil	649

TABLE 5—INDIVIDUAL TEST DATA FOR UPPER ZONE, WELL NO. 1—LOWER ZONE BLANKED-OFF

Date	Surface Tubing Pressure (psig)	Production: Oil (B/D)	Production: Gas (Mcf/D)	Gas-Oil Ratio (cu ft/bbl)
6-9-60	900	10.39	242	23,300
6-10-60	900	10.68	237	22,100
6-11-60	900	10.98	238	21,700
6-12-60	900	10.97	238	21,700
	Average	10.75	239	22,100

TABLE 6—COMBINED PRODUCTION DATA AND ALLOCATION TO EACH ZONE, WELL NO. 1

Date	Surface Tubing Pressure (psig)	Measured Production		Calculated Production			
				Upper Zone		Lower Zone	
		Total Liquid (B/D)	Total Gas (Mcf/D)	Oil (B/D)	Gas (Mcf/D)	Condensate (B/D)	Gas (Mcf/D)
6-16-60	900	28.92	498	10.75*	239*	18.17	259
6-17-60	900	30.07	463	10.75	239	19.32	224
6-18-60	900	23.69	442	10.75	239	12.94	203
6-19-60	900	26.87	452	10.75	239	16.12	213
6-20-60	900	27.45	466	10.75	239	16.70	227

*Based on predetermined tests shown in Table 5.

Well No. 2

Well 2 was completed in May, 1961. The upper zone on drill-stem test was judged to be noncommercial but did produce some oil. This is a situation frequently confronting an operator. A zone looks doubtful on an electric log and a drill-stem test is not conclusive—should he make a single or dual completion? It is a perplexing question. The great expense involved in twin-string duals will not often justify a thorough evaluation of these doubtful zones. On the other hand, he may be passing up a commercial reserve. The multiple-completion choke assembly can be used to good advantage in this situation. Doubtful producing horizons can be fully evaluated at low additional cost and, when combined with good producers, can be depleted without artificial lift. This will result in the recovery of more oil and more gas.

Well 2 is a deep, directionally drilled, high-pressure, high-temperature well—a water location—and provided quite a test for the tool. The wireline operations in this well, however, have gone quite smoothly.

Well No. 3

Well 3 was originally a single-completion oil well. In June, 1961, the oil zone was dualled with a deeper sand productive of gas and condensate.

Table 8 gives the results of single-zone tests of the lower zone; Fig. 4 is a graphic representation of these data. Note that the well goes into critical flow at a tubing inlet pressure of 1,835 psi, or 55 per cent of the upstream pressure of approximately 3,300 psi.

After the tests of the lower zone were concluded, the upper zone was tested and then the two zones were combined. The tubing inlet pressure at 7,550 ft was measured with a bottom-hole pressure gauge and found to be 1,720 psi with a surface tubing pressure of 1,100 psi. As a check, the depth-pressure gradient curves were used to determine the tubing inlet pressure under these conditions of flow. This value was interpolated to be 1,650 psi. The lower zone is in critical flow under these conditions. This means that the predetermined rate of production of the lower zone is not affected by combining with the upper.

TABLE 7—INDIVIDUAL TEST DATA FOR UPPER ZONE, WELL NO. 1—LOWER ZONE BLANKED-OFF

Date	Choke Size (in.)	Production: Oil (B/D)	Production: Gas (Mcf/D)
7-24-60	5/64	7.23	248
10-5-60	6/64	7.80	227
10-18-60	5/64	7.80	227
12-4-60	5/64	7.23	209
1-27-61	3.5/64	6.38	175
5-29-61	3.5/64	6.96	150

TABLE 8—INDIVIDUAL TEST DATA OF LOWER ZONE, WELL NO. 3—UPPER ZONE BLANKED-OFF

Tubing Pressure (psig)		Production	
Surface	Inlet	Condensate (B/D)	Gas (Mcf/D)
790	1,466	38.40	726,802
950	1,549	39.41	726,802
1,060	1,835	37.34	708,654
1,250	2,091	32.12	638,787
1,335	2,345	30.06	555,196
1,475	2,517	22.82	454,251
1,600	3,125	12.44	222,078

Well No. 4

Well 4, a water location, was completed in June, 1961. The upper zone is only 8-ft thick and would not justify the additional cost of a twin-string dual.

Production tests of the lower zone with a 4.5/64-in. choke bean in the orifice head were made as shown in Table 9.

These tests show that the well goes out of critical flow when the surface pressure is increased manually above 250 psi. Plotting oil rate vs tubing pressure locates the critical point at 875 psi.

Following these tests, the orifice head was pulled and run back with the lower zone blanked and a 4.5/64-in. choke bean controlling production from the upper zone. On stabilized test in critical flow, the upper zone produced 152 BOPD (neither zone produces salt water) with a gas-oil ratio of 720 cu ft/bbl.

The orifice head was then pulled and returned with each zone open to a 4.5/64-in. choke bean. Combined production was gauged at 311 BOPD, a good check with the individual zone tests (157 and 152, a total of 309 BOPD).

TABLE 9—WELL DATA, LOWER ZONE, WELL NO. 4

Oil Production (B/D)	Gas-Oil Ratio (cu ft/bbl)	Surface Tubing Pressure (psi)
156	827	150
158	919	150
157	936	250
149	905	975
138	972	1,075
122	957	1,200
100	900	1,450

Well No. 5 Through 7

Well 5 was a singly-completed, deficient oil well when it was dually-completed in Aug., 1961, with a gas zone. The oil zone was not good enough to support a twin-string completion and would have been abandoned had not the multiple-completion choke assembly been available.

Well 6, a water location, was completed in Aug., 1961, and has been produced without incident.

Well 7, another water location, was completed in Aug., 1961. Tests show that both zones are in critical flow. Each zone was tested separately. The lower zone made 65 BOPD, and the upper zone was tested at 71 BOPD. When combined, the two zones produced 132 BOPD.

Well No. 8

Well 8, the first test in Texas, was worked-over and completed as a dual in Oct., 1961. This well is completed in a low-pressure gas sand and a low-pressure oil sand. The gas is used to lower the gradient in the well to allow flow from the oil zone. The low bottom-hole pressure existing in the gas

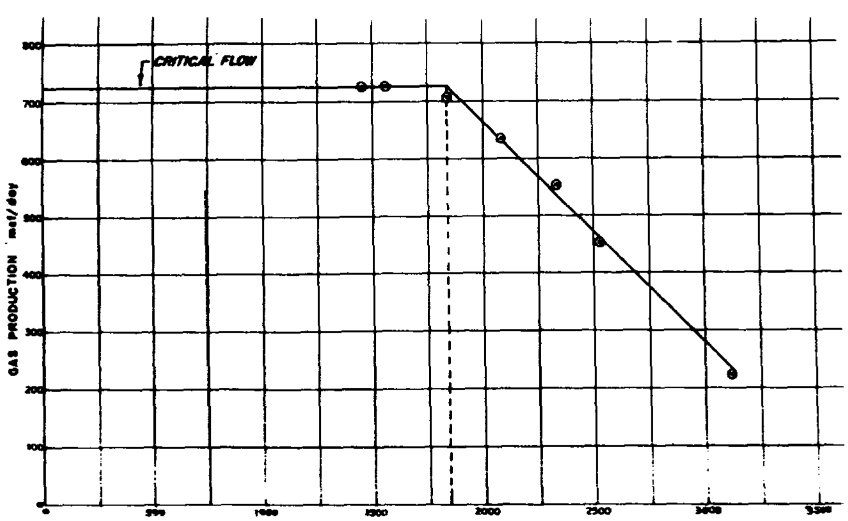

Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

sand will not justify the surface facilities that would be required for the sale of the gas, nor will the low pressure justify the use of this gas in a conventional gas-lift system.

A new check valve received its first subsurface test in Well 8. Results were quite encouraging, and the valve subsequently has been used in other wells. The lower zone in Well 8 was acidized with the new check valve protecting the upper zone. The treatment was successful mechanically, and the check valve functioned perfectly. Maximum differential pressure across the check valve during acidizing was 4,000 psi.

This new check valve is a sleeve-type steel valve incorporating both a metal-to-metal and an O-ring seal. In time, it may replace entirely the resilient-type check valve.

The required packer-leakage test in Well 8 was obtained by blanking-off the upper zone in the orifice head and flowing the upper zone through the casing. The lower zone was open to the tubing. The casing and tubing pressures were recorded simultaneously. This is the method for obtaining a packer-leakage test when there is no packer set above the upper zone. If the upper packer is set, packer-leakage tests can be made by measuring the bottom-hole pressure of one zone while flowing the other. A device is now available which will allow a bottom-hole pressure element to be run with the orifice-head assembly. The shut-in bottom-hole pressure of one zone is measured while the other is open to flow. This type of packer-leakage test should be more realistic than the conventional test where surface pressure fluctuations are observed.

Allocation tests in Well 8 are made by blanking-off the lower zone and measuring the gas produced from the upper zone through the tubing. The two zones are then combined and the increase in gas rate is calculated from the orifice-meter chart. This increase represents the volume of gas produced from the lower zone. All liquids produced are known to have come from the lower zone, as the upper zone produces dry gas. The tubing inlet pressure is measured. The results show that the upper zone is in critical flow. This means that production from the lower zone has no effect on the predetermined rate from the upper zone.

It can be argued that this method of gas measurement is considerably more accurate than the usual method of measuring gas into and out of a conventional, intermitting-type gas-lift well.

Economics

Use of the multiple-completion choke assembly to produce two reservoirs simultaneously through a single flow string results in an initial saving in equipment and rig costs, and in later workover costs, when compared with twin-string duals.

The savings possible cover a wide range. For example, the equipment costs of Well 6 are compared with those of a twin-string dual in the same field, on a comparative-footage basis, in Table 10. This represents a difference of $42,131 and includes neither the saving in rig time nor the considerable saving in workover costs which may result. Anyone who has worked-over a deep twin-string dual in a water location will attest—perhaps grimly—to the costs that can be incurred in such operations.

At the other end of the scale, in the relatively shallow wells, a cost comparison between tubular requirements in three different types of dual completions is shown in Table 11.

Initial completion operations conceivably might result in the tubingless-completion dual costing more than the single-string dual.

Simplicity and flexibility always should be taken into account when planning the system that will produce the most hydrocarbons for the least money.

The wireline expense associated with the simultaneous, one-flow-string method will depend primarily upon operator skill, accessibility of location, depth and testing requirements. This expense will be relatively high for the first month or two, and then will taper off. Wireline costs for the year 1961 in Well 1 have averaged $65 per month. In many wells, as in Well 1, the wireline expense will be more than compensated for by increased production, reduced lifting costs and greater ultimate recovery.

TABLE 10 — TUBULAR-GOODS COST OF TWIN-STRING VS SINGLE-STRING DUAL COMPLETION

	Well "X"	Well No. 6
Conductor	$ 788 (20 in.)	$ 538 (16 in.)
Surface	13,981 (11¾ in.)	11,200 (10¾ in.)
Oil String	61,500 (7⅝ in.)	39,600 (5½ in.)
Tubing	27,000 (2⅜ in.)	11,200 (2⅜ in.)
Wellhead Costs	5,200	3,800
Total	$108,469	$66,338

Acceptance By Regulatory Agencies

Permission to use the multiple-completion choke assembly in Well 1 was granted by the Louisiana Conservation Commission on a six-month basis, and then extended permanently for that particular well. Approval for the other two Kinder wells was obtained after a public hearing. The hearing was necessary because the lower producing sand was unitized and created a diversity of ownership in those wells.

Approval for the other Louisiana installations has been obtained after filing a routine request for permission to dually complete, with the provision that a review of the well be made after a six-month operational period.

In Texas, the Railroad Commission has been somewhat stymied by Statewide Rule 15, which says "No well shall be permitted to produce oil and/or gas from different strata through the same string of casing".

This rule was written some 27 years ago to prevent an operator from indiscriminately opening two or more zones in the same wellbore, and commingling this production without regulation or proper identification as to source.

The Railroad Commission, after a public hearing, granted an exception to Rule 15 in the case of Well 8. It was emphasized at the hearing that the old concept of commingling did not apply to wells equipped with the multiple-completion choke assembly, and that there was no basic difference between this and conventional methods inasmuch as commingling occurred *after* regulation, as it does in any tank battery where surface commingling takes place.

There are really no statutory obstacles to Railroad Commission acceptance of this producing method. Opinion No. 0-2245 concerning "The right of an operator to utilize gas produced from an upper horizon in lifting the oil produced from an oil sand at a lower horizon, without first producing the gas at the surface", was approved on May 20, 1940, by Texas Attorney General Mann and by his Opinion Committee. They ruled as follows: "So long as the proper steps are

TABLE 11—TUBULAR-GOODS COST OF SINGLE-STRING VS TWIN-STRING AND TUBINGLESS COMPLETION

	Twin String			Tubingless			Single String		
	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost
Surface	500	9⅝	$ 1,750	500	9⅝	$1,750	500	9⅝	$ 1,750
Oil String	4,600	7	9,450	9,000	2⅞	7,450	4,600	5½	6,750
Tubing	9,000	2⅜	5,600	None	—	—	4,500	2⅜	2,800
Total			$16,800			$9,200			$11,300

taken to insure against the escape of oil or gas from one stratum into another, we do not believe that the statutes prevent the Commission from permitting the more efficient method of introducing the gas into the tubing below the surface, instead of requiring that the gas first be brought to the surface through a separate string of casing and then reintroduced into the well".

Other Applications

Use of the multiple-completion choke assembly is not limited to the applications that have been described. For example, the device is ideally suited to dual gas wells, and is being used in such wells in Mexico. Other, more specialized, installations are illustrated in Figs. 5 through 10. The single-string dual tubingless completion shown in Fig. 10 must surely represent the final stage in the reduction of initial equipment costs for dual completions.

Operational Suggestions

Following are some suggestions to those who contemplate using the multiple-completion choke assembly.

1. Set tubing with as little compression as possible to facilitate wireline operations.

2. Install the side-door choke in the landing nipple when the tubing is run to permit washing the well around the bottom of the tubing.

3. Pull the side-door choke and clean both zones before running the check-valve assembly, unless the differential in bottom-hole pressures is too great.

4. Use a wireline operator experienced in the operation of the multiple-completion choke assembly. Be sure he has good equipment on the job, including a sensitive weight indicator.

5. If the lower zone is protected by a check valve, do not run the orifice head with a blank in the opening communicating with the lower zone. This is similar to forcing a piston into a closed cylinder containing liquid, and will cause destruction of the O-ring seals on the tube and possible bending of the tube. This situation arises only when the lower zone is the weak zone and requires a check valve. Under these circumstances, when a test is made of the upper zone alone, the O-rings should be left off the tube of the orifice-head assembly. The higher pressure of the upper zone acting against the check valve of the lower zone will prevent flow from the lower zone.

6. Take extra precautions to assure accurate measurement of the fluids produced during tests. This is very important and should be stressed with field personnel.

7. For especially severe service, the metal sleeve-type check valve with an O-ring seal is recommended.

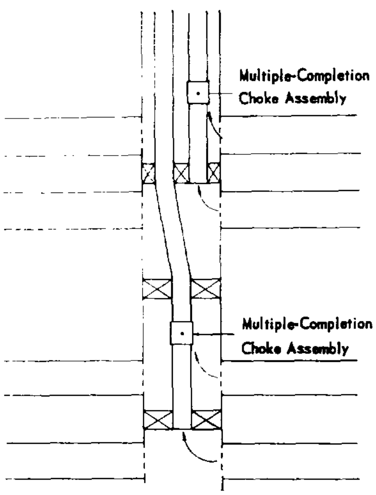

Fig. 5—Two-string quadruple completion.

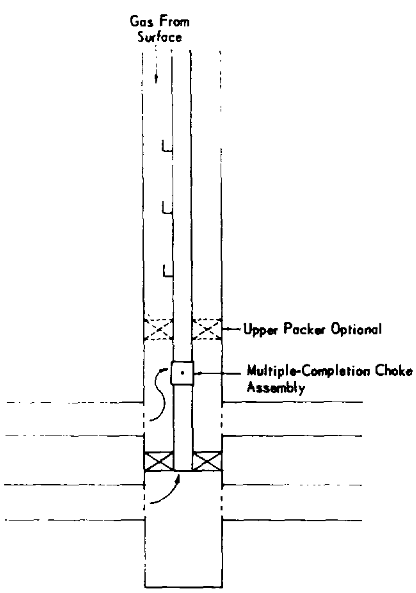

Fig. 6—Gas-lifting two zones with one string of flow valves.

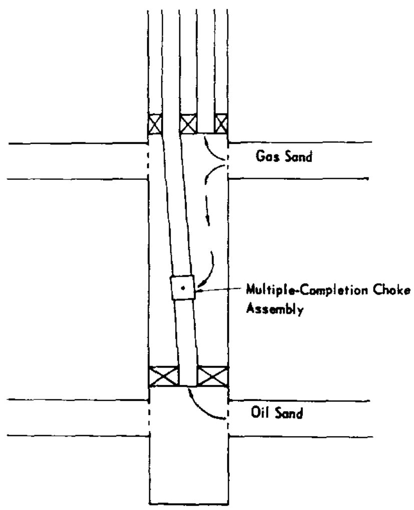

Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

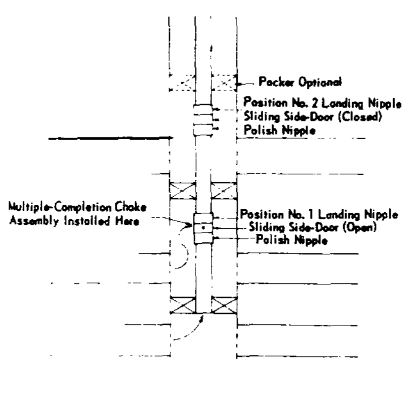

Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

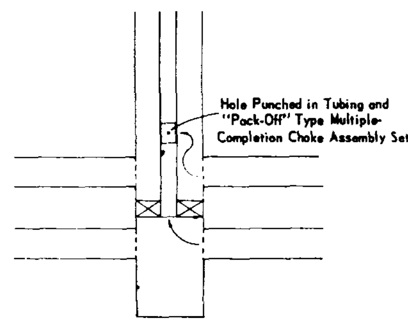

Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

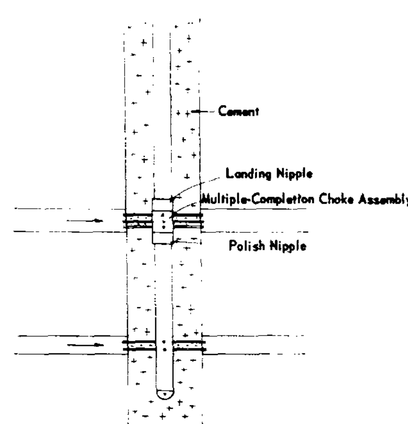

Fig. 10—One-string dual tubingless completion.

Future Development

The future development of the multiple-completion choke assembly and the method of simultaneous production through a single flow string is projected along the following two lines.

1. Surface-recorded bottom-hole pressures will be used to facilitate allocation and packer-leakage tests. A large portion of the wireline work could be eliminated if one had knowledge of the two pressures upstream from the choke and the tubing inlet pressure.

2. Informative material will be presented to state regulatory agencies in an effort to secure general acceptance of the process. This is largely a matter of demonstrating the feasibility of the method, both legally and mechanically, and showing that it will effect conservation and prevent waste.

Conclusions

Simultaneous production of two reservoirs through a single flow string can result in a significant reduction in completion and lifting costs, and will increase current income and ultimate recovery. The multiple-completion choke assembly can be used to maintain separation of the reservoirs and to control the rate of production from each. Test procedures have been developed which provide an acceptable method of determining the contribution from each zone. All requirements imposed by the various regulatory agencies can be satisfied.

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New Tool Permits Simultaneous Production of Two Reservoirs Through the Same Flow String

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Abstract

The constant search for methods to increase the efficiency of production systems and to reduce operating costs has led to the development of a wireline tool which makes it possible to produce and control two separate reservoirs through a single string of tubing. This paper is a progress report of the experience one company has gained with this tool in eight of its dually completed wells in Louisiana and Texas. Field tests have clearly demonstrated that this device can be used to maintain separation of production from two reservoirs, to control and determine the rate of production from each, and to change the rate of production as required. The advantages in simultaneous one-string multiple completions are enumerated, and various applications of the method are discussed.

Introduction

It is now almost standard operating procedure to complete wells in more than one zone wherever possible, with the great majority of these multiples being dual completions. This is a sign of the times. Saving must be accomplished wherever possible; however, there is no need to expand on this theme. All are painfully aware of the economic conditions within the industry. It is sufficient to say that the practice of multiple completions is here to stay and is becoming more popular every day. The only question is whether or not the practice has evolved into its most acceptable form.

The earlier duals were the concentric type, with one zone producing through the tubing and the other through the tubing-casing annulus. This method is still practiced to a large degree. It is popular because it is relatively inexpensive. Unfortunately, it has some rather severe limitations, with which the reader undoubtedly is familiar.

The twin-string dual is an improvement over the concentric in the sense that many of the problems associated with the concentric have been solved. The objectionable features of the twin-string dual are the high cost of equipping the well with an extra string of tubing, plus accessories, and the complications brought on by cramming all this tubing into one string of casing.

Still another type of multiple is the tubingless completion, wherein two or more small casing strings are cemented in place and subsequent operations performed with miniaturized equipment.

The purpose of this paper is to present a different concept in multiple completion—the simultaneous production of separate reservoirs in a single flow string. This method combines the simplicity and low cost of the concentric with the flexibility of the twin-string dual. In addition, it provides the unique advantage of prolonging natural flow from a low-pressure zone by combining its production with the fluids produced from a higher-pressure zone. The wireline tool which makes this method possible is the multiple-completion choke assembly.

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Construction and Operation of the Multiple-Completion Choke Assembly

Fig. 1 shows a well properly equipped to receive a multiple-completion choke assembly. A conventional packer separates the two producing zones. The upper packer is optional. A side-door choke landing-nipple hookup is located in the tubing

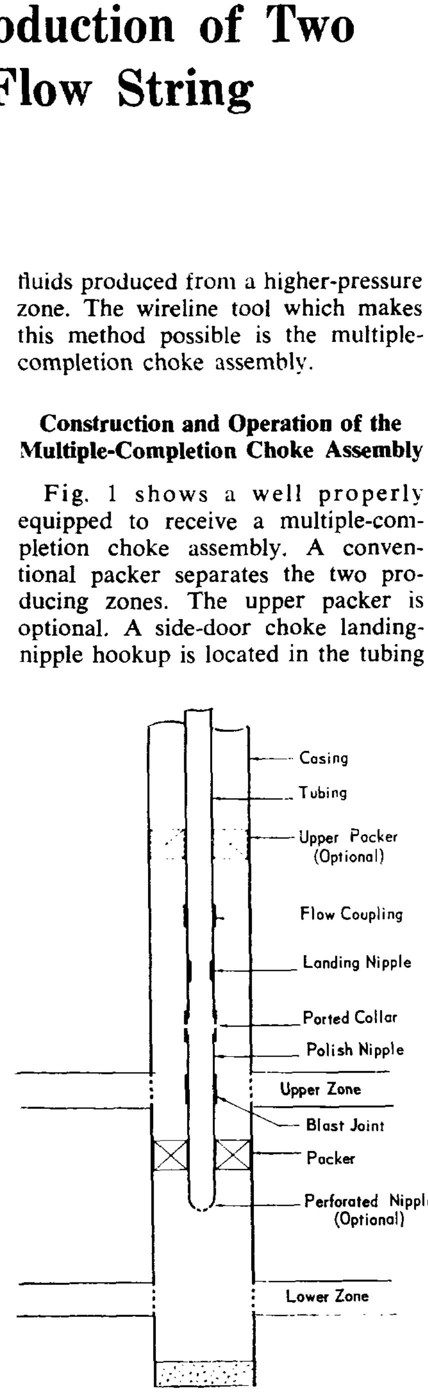

Fig. 1—Well properly equipped for multiple-completion choke assembly.

string above the lower packer. The multiple-completion choke assembly will be locked in this landing nipple. Normally located a joint or two above the upper zone, the position of the landing-nipple hookup can be varied to suit well conditions. For example, where the two zones are widely separated, it might be placed just above the lower packer to facilitate bottom-hole pressure tests of the lower zone.

The tool consists of two separate assemblies. The outer assembly, which is run independently and locked in the landing nipple, contains the check valves and packing seals which prevent flow from one zone to the other. In practice, however, only one check valve is usually required and is installed to protect the zone with the lower pressure.

The orifice-head assembly, which carries the tungsten-carbide choke beans, is run separately and is seated and locked in the outer assembly. The method of running each section is illustrated in Fig. 2.

Fig. 3 is a schematic drawing which shows more clearly how the device works. Production from the lower zone enters the assembly through a slotted section, flows around a resilient sleeve-type check valve, enters, and flows through the tube of the orifice-head assembly; it is choked and—now regulated—flows into the tubing. Produced fluids from the upper zone enter the casing opposite a blast joint on the tubing, flow through the ported collar of the side-door choke landing-nipple hookup, through the upper slotted secion, around the upper check valve, into the annulus surrounding the tube and through the upper-zone choke bean into the tubing. Here the two controlled flow streams, which have been kept separate up to this point, combine and flow to the surface.

Tubing Inlet Pressure

The pressure in the tubing at the junction of the two streams will be the minimum pressure required to lift the combined fluids to the surface (at zero surface pressure) and will be determined essentially by the gas-liquid ratio, production rate and tubing size. This pressure, which will hereafter be referred to as the "tubing inlet pressure", is of particular interest because of its importance in the application of the multiple-completion choke assembly. For example, suppose that investigation is being made into the possibility of using the assembly in a two-zone oil well with characteristics as tabulated in Table 1.

The combined production rate is 160 B/D of liquid (including salt water) and 87 Mcf/D of gas. The combined gas-liquid ratio is 543 cu ft/bbl. With a multiple-completion choke assembly set at 6,500 ft in $2\frac{3}{8}$-in. OD tubing, it can be determined from published depth-pressure gradient curves[1] that the tubing inlet pressure will be approximately 850 psi.

The upper zone, with a productivity index of 0.5, will produce 96 B/D of liquid with a flowing bottom-hole pressure of approximately 1,308 psi. Since the flowing bottom-hole pressure of the weaker zone is greater than the tubing inlet pressure at the desired rate of production, this well can be produced by natural flow with a multiple-completion choke assembly. Natural flow will be maintained so long as the flowing bottom-hole pressure of the weaker zone (in this example, the upper zone) exceeds the tubing inlet pressure. At some point in the life of the upper zone, however, conditions favorable for natural flow *as a single completion* would no longer prevail. In other words, if it were being produced independently, some form of artificial lift would be required. The requirement is postponed because of the availability of the gas from the lower zone. When the lower zone can no longer "carry" the upper, a single set of flow valves can be run to produce both zones through the multiple-completion choke assembly.

TABLE 1—WELL DATA USED IN EVALUATING APPLICATION OF MULTIPLE-COMPLETION TOOL

	Upper Zone	Lower Zone
Producing Depths (ft)	6,600	7,200
Static BHP (psi)	1,500	3,400
Productivity Index (B/D/psi drop)	0.5	1.0
Oil Produced (B/D)	56	64
Salt Water Produced (B/D)	40	None
Gas Produced (Mcf/D)	39	48
Gas-Liquid Ratio	406	750

Allocation of Production

Allocation of fluids produced from each zone is based on a separate, individual zone test. To obtain such a test, the orifice-head assembly is removed from the check-valve assembly and brought to the surface with conventional wireline tools. (Removal of

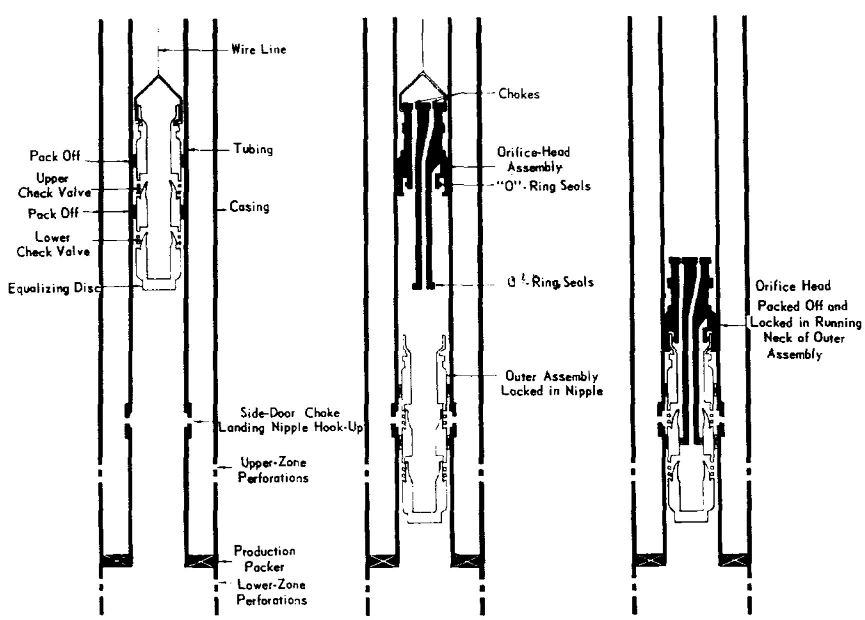

Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

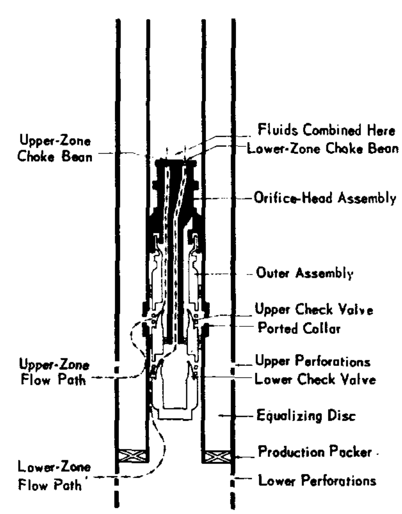

Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

the orifice head does not result in interzone flow, as the check-valve assembly remains in the well.) If the lower zone is to be tested, a blank bean is inserted in the opening in the orifice head communicating with the flow path of the upper zone. A choke bean, properly sized[1] to produce the desired volume of fluid from the lower zone, is placed in the opposite side of the orifice head. The orifice head is then lowered into the well, and landed and locked in the check-valve assembly. The upper zone cannot flow because of the blank choke bean. Produced fluids from the lower zone are measured into conventional surface facilities until a stabilized 24-hour test is obtained. The orifice head is again removed from the well. The blank bean is replaced with a production bean, and the assembly is returned to its operating position in the well. A stabilized test of the combined fluids produced is obtained. The predetermined rate from the lower zone is subtracted from the combined total, with the difference assigned to the upper zone.

The test procedure used will be determined by the flow conditions present in the well—specifically, whether or not one of the zones is in critical flow. A stream is said to be in critical flow when alterations in pressure downstream from an orifice do not affect the rate of flow through the orifice. The critical point occurs when the downstream pressure is 53 per cent of the upstream pressure. The significance of this phenomenon in the operation of the multiple-completion choke assembly is that, if one of the zones is in critical flow and the other is not, the zone not in critical flow can be regulated with a surface control without affecting the rate from the other. In the well described earlier, for example, if the tubing inlet pressure is not allowed to exceed approximately 1,765 psi (53 per cent of 3,336 psi), the rate from the lower zone will not be affected. In other words, back-pressure at the surface can be increased to the point of actually shutting-in the upper zone, with no effect on the rate from the lower zone.

In any well where two reservoirs are being produced simultaneously through the multiple-completion choke assembly, one of the following three conditions will exist: (1) one zone will be in critical flow; (2) neither zone will be in critical flow; or (3) both zones will be in critical flow. The method of testing for allocation will depend upon which one of these conditions exists.

The exact value of the critical P_2/P_1 ratio, whether it be 53 per cent or some other value, is of no particular concern. The ratio is not used quantitatively. As a matter of interest, however, in the wells where this critical point has been observed, the value has appeared reasonably close to 53 per cent.

The exact point of critical flow can be determined by changing the surface tubing pressure with an adjustable choke, measuring the rate of flow into conventional test facilities and observing the effect of the back-pressure changes.

At the same time, the tubing inlet pressure is measured with a bottom-hole pressure gauge. For example, tests run on a certain zone in a dual completion might result in the data shown in Table 2.

These data show the stream is going into critical flow between a tubing inlet pressure of 1,050 and 825 psi. This point can be determined more precisely if the results are shown graphically, as will be illustrated later in actual well tests.

A predetermined rate for this particular zone on a specific choke size for this range of tubing inlet pressures has now been established. It makes no difference what effect, if any, the second zone may have on the tubing inlet pressure in the well. Because this pressure can be determined, the rate from the first zone will be known. The difference is then assigned to the zone not tested individually, usually the lower-pressure zone.

If each zone can produce its allowable independently of the other, there may be some reason to test each separately. This procedure, of course, will require additional wireline work and is not essential in determining the production from each zone. The method has been used occasionally to demonstrate the consistency of flow-rate control possible with the choke beans in the tool.

Summarizing, production tests will follow one of two patterns. If either or both of the two zones is in critical flow when combined, a 24-hour stabilized test of the zone with the higher pressure is obtained. Back-pressure is not adjusted during this test. Following this, both zones are combined and tested for 24 hours at a stabilized rate. The difference in production is known to have come from the zone not tested singly.

If neither of the zones is in critical flow, the zone with the higher pressure is tested individually. The surface pressure is varied and the stabilized rates of production at the various back-pressures are measured. Tubing inlet pressure is recorded with a bottom-hole pressure gauge. This test predetermines the rate to be expected from this zone during periods of combined flow. The rate from the other zone will be determined by difference.

TABLE 2—CRITICAL FLOW DATA

Surface Tubing Pressure (psi)	Tubing Inlet Pressure (psi)	Liquid Rate (B/D)
700	1,300	50
500	1,050	55
300	825	60
100	600	60

Use Of The Tool In Gas Lifting

The multiple-completion choke assembly, when used as a gas-lift device, is in effect a single-point injection, retrievable flow valve utilizing gas supplied directly from the formation at maximum efficiency. An expert in gas-lift technology, in discussing conventional gas-lift systems,[2] has made the following pertinent observations.

> Which flow process, continuous or intermittent, will yield the greatest amount of produced stock-tank liquid for the least amount of injected gas at the available pressures? The continuous-flow process, if properly instituted, should be inherently more efficient than that of intermittent flow. The gas is put to work as needed and the high dissipation of initial energy in overcoming starting inertia is largely absent. Also, the external work done by the gas is negligible. The fact is, however, that maximum efficiency in the continuous-flow process can only be realized by putting the gas to work as soon as possible. This means high injection pressures at moderate depths. Because the high injection pressures necessary for maximum efficiency are seldom available, it has been found in practice that the intermittent-flow process is frequently more efficient than that of continuous flow, for wells that produce moderate amounts of liquid.

It is significant to point out here that the Phillips paper, previously referred to, lists data from some 34 flowing wells and 16 gas-lift wells (continuous flow). The thermodynamic flow efficiency for the flowing wells was on the order of 85 to 95 per cent, whereas the gas-lift wells were mainly of the order of 40-60 per cent. There is no reason why continuous-flow gas-lift wells should not closely approximate the efficiency of naturally flowing wells, if the installations are correctly designed.

It is recognized that the high-pressure requirements for maximum efficient operations is definitely a limiting factor in any practical well installation. It is most important to recognize that, as injection pressures are decreased below the optimum, the flow efficiency

[1]References given at end of paper.

of the installation falls off very rapidly. Low injection pressures mean high injection GORs and should be avoided where possible.

. . . and to emphasize the advantage of valve installations in which the valves may be retrieved and reset or replaced.

These statements make a strong case for using the multiple-completion choke assembly as a gas-lift mechanism. The high injection pressures necessary for maximum efficiency are now within practical reach. Almost any well can be produced by continuous lift. The "flow valve" can be removed and replaced by wireline. All this adds up to maximum efficiency at minimum cost.

To illustrate the truly significant potential of the multiple-completion choke assembly as it applies to gas lift, a comparison was made between gas lifting with a conventional system and with the multiple-completion choke assembly in a well in the Sour Lake field, Hardin County, Tex. The Railroad Commission of Texas has granted permission to use in this well a gas sand at 9,610 ft to supply gas-lift gas through the multiple-completion choke assembly to lift produced fluids from an oil sand at 9,800 ft. The results of this study[3] were rather startling. The input gas required using the conventional system was calculated to be 560 Mcf/D as compared to only 34 Mcf/D using the multiple-completion choke assembly; in addition, it should be remembered that the latter method does not require surface gas-lift facilities such as high-pressure separators or compressors, heaters, dehydration equipment, delivery lines, etc.

Data pertinent to the analysis and the results thereof are presented in Table 3.

Field Tests

Sun Oil Co.'s first test of the multiple-completion choke assembly was in the Kinder field, Allen Parish, La., in Sept., 1959.

Additional development and testing were done in the North Winnie field in a surface manifold with a high-pressure oil well flowing through the tool. Sand-laden liquid was pumped into the flow stream where it entered the manifold. The severity of these and other surface and subsurface tests has resulted in the development of a very durable and rugged tool.

Well No. 1

The first successful field test was begun March 31, 1960, in a well in the Kinder field. The Louisiana Conservation Commission approved a six-month test period and, after a three-month interval, granted permanent approval to use the tool in this well, which will be identified as Well No. 1.

Sun now has eight wells equipped with multiple-completion choke assemblies, and several more installations either are planned or are in progress. A description of the wells now equipped with the assembly appears in Table 4.

Well 1, prior to installation of the multiple-completion choke assembly, was a concentric-type dual completion with the upper zone flowing in the annulus between 2⅜-in. tubing and 5½-in. casing and the lower zone flowing through the 2⅜-in. tubing. As a result of using the tool, the combined hydrocarbon production from the two zones was increased by approximately 20 B/D and 300 Mcf/D, representing an annual increase in gross income of $48,400.

Tables 5 and 6 illustrate the exact method used to allocate production from the two zones in Well 1. Table 5 represents four consecutive 24-hour tests of stabilized flow from the upper zone with the lower zone closed in by a blank choke bean in the orifice head. It is not necessary, as a routine matter, to run the tests this long. The tool was experimental during this period, and the stabilized nature of the flow possible with the device was being demonstrated. Table 6 represents tests made of the combined flow, with the resulting allocation to each zone.

Table 7 shows the results obtained during the following months when testing the upper zone individually, and demonstrates the accurate flow-rate control possible with the choke beans used in the assembly. The same 5/64-in. choke was used throughout the period shown. Gas production was measured by orifice meter and liquid production was gauged in a 210-bbl tank.

TABLE 3—GAS-LIFTING WITH MULTIPLE-COMPLETION TOOL COMPARED TO CONVENTIONAL METHOD

Conditions

Required Production (B/D)	100 oil, 100 SW
Productivity Index (B/D/psi drop)	0.154
Surface Pressure (psi)	100
Static BHP Lower Zone (psi)	3,800
Static BHP Upper Zone (psi)	4,000
Gas-Oil Ratio Lower Zone (cu ft/bbl)	500
Gas-Liquid Ratio Lower Zone (cu ft/bbl)	250
Required Gas-Liquid Ratio for Well to Flow (cu ft/bbl)	420
Input Gas Pressure (psi)	700

Comparison Between the Two Methods

	Conventional	Proposed
Number of Flow Valves	11	1
Depth of Lift (ft)	4,500	9,500
Input Gas-Liquid Ratio (cu ft/bbl)	2,800	170 (420-250)
Gas Required (Mcf/D)	560	34

TABLE 4—DESCRIPTION OF WELLS USING MULTIPLE COMPLETION TOOL

Well No.	Location	Depth (ft)	Static BHP (psi)	Production (B/D)	Gas-Liquid Ratio (cu ft/bbl)
1	Kinder, La.	8,067	2,575	6 Oil	22,100
		8,448	2,460	19 Cond.	18,466
2	Bayou Sale, La.	14,025	5,870	20 Oil	1,000
		14,236	6,533	75 Oil, 75 SW	7,750
3	Kinder, La.	7,678	3,263	64 Oil	784
		8,379	3,371	37 Cond.	19,100
4	Belle Isle, La.	13,958	6,500	129 Oil	735
		13,983	6,500	129 Oil	945
5	Kinder, La.	7,394	3,290	7 Oil, 15 SW	643
		8,390	3,485	64 Cond.	16,188
6	Belle Isle, La.	12,840	5,670	115 Oil	906
		13,398	5,781	129 Oil	423
7	Bateman Lake, La.	10,154	4,538	71 Oil	2,929
		11,700	5,060	65 Oil, 10 SW	3,354
8	Sour Lake, Tex.	4,710	814	No Cond., No SW	113 Mcf Dry Gas
		4,788	1,093	14 Oil	649

TABLE 5—INDIVIDUAL TEST DATA FOR UPPER ZONE, WELL NO. 1—LOWER ZONE BLANKED-OFF

Date	Surface Tubing Pressure (psig)	Production: Oil (B/D)	Production: Gas (Mcf/D)	Gas-Oil Ratio (cu ft/bbl)
6-9-60	900	10.39	242	23,300
6-10-60	900	10.68	237	22,100
6-11-60	900	10.98	238	21,700
6-12-60	900	10.97	238	21,700
	Average	10.75	239	22,100

TABLE 6—COMBINED PRODUCTION DATA AND ALLOCATION TO EACH ZONE, WELL NO. 1

		Measured Production		Calculated Production			
				Upper Zone		Lower Zone	
Date	Surface Tubing Pressure (psig)	Total Liquid (B/D)	Total Gas (Mcf/D)	Oil (B/D)	Gas (Mcf/D)	Condensate (B/D)	Gas (Mcf/D)
6-16-60	900	28.92	498	10.75*	239*	18.17	259
6-17-60	900	30.07	463	10.75	239	19.32	224
6-18-60	900	23.69	442	10.75	239	12.94	203
6-19-60	900	26.87	452	10.75	239	16.12	213
6-20-60	900	27.45	466	10.75	239	16.70	227

*Based on predetermined tests shown in Table 5.

Well No. 2

Well 2 was completed in May, 1961. The upper zone on drill-stem test was judged to be noncommercial but did produce some oil. This is a situation frequently confronting an operator. A zone looks doubtful on an electric log and a drill-stem test is not conclusive—should he make a single or dual completion? It is a perplexing question. The great expense involved in twin-string duals will not often justify a thorough evaluation of these doubtful zones. On the other hand, he may be passing up a commercial reserve. The multiple-completion choke assembly can be used to good advantage in this situation. Doubtful producing horizons can be fully evaluated at low additional cost and, when combined with good producers, can be depleted without artificial lift. This will result in the recovery of more oil and more gas.

Well 2 is a deep, directionally drilled, high-pressure, high-temperature well—a water location—and provided quite a test for the tool. The wireline operations in this well, however, have gone quite smoothly.

Well No. 3

Well 3 was originally a single-completion oil well. In June, 1961, the oil zone was dualled with a deeper sand productive of gas and condensate.

Table 8 gives the results of single-zone tests of the lower zone; Fig. 4 is a graphic representation of these data. Note that the well goes into critical flow at a tubing inlet pressure of 1,835 psi, or 55 per cent of the upstream pressure of approximately 3,300 psi.

After the tests of the lower zone were concluded, the upper zone was tested and then the two zones were combined. The tubing inlet pressure at 7,550 ft was measured with a bottom-hole pressure gauge and found to be 1,720 psi with a surface tubing pressure of 1,100 psi. As a check, the depth-pressure gradient curves were used to determine the tubing inlet pressure under these conditions of flow. This value was interpolated to be 1,650 psi. The lower zone is in critical flow under these conditions. This means that the predetermined rate of production of the lower zone is not affected by combining with the upper.

Well No. 4

Well 4, a water location, was completed in June, 1961. The upper zone is only 8-ft thick and would not justify the additional cost of a twin-string dual.

Production tests of the lower zone with a 4.5/64-in. choke bean in the orifice head were made as shown in Table 9.

These tests show that the well goes out of critical flow when the surface pressure is increased manually above 250 psi. Plotting oil rate vs tubing pressure locates the critical point at 875 psi.

Following these tests, the orifice head was pulled and run back with the lower zone blanked and a 4.5/64-in. choke bean controlling production from the upper zone. On stabilized test in critical flow, the upper zone produced 152 BOPD (neither zone produces salt water) with a gas-oil ratio of 720 cu ft/bbl.

The orifice head was then pulled and returned with each zone open to a 4.5/64-in. choke bean. Combined production was gauged at 311 BOPD, a good check with the individual zone tests (157 and 152, a total of 309 BOPD).

TABLE 9—WELL DATA, LOWER ZONE, WELL NO. 4

Oil Production (B/D)	Gas-Oil Ratio (cu ft/bbl)	Surface Tubing Pressure (psi)
156	827	150
158	919	150
157	936	250
149	905	975
138	972	1,075
122	957	1,200
100	900	1,450

Well No. 5 Through 7

Well 5 was a singly-completed, deficient oil well when it was dually-completed in Aug., 1961, with a gas zone. The oil zone was not good enough to support a twin-string completion and would have been abandoned had not the multiple-completion choke assembly been available.

Well 6, a water location, was completed in Aug., 1961, and has been produced without incident.

Well 7, another water location, was completed in Aug., 1961. Tests show that both zones are in critical flow. Each zone was tested separately. The lower zone made 65 BOPD, and the upper zone was tested at 71 BOPD. When combined, the two zones produced 132 BOPD.

Well No. 8

Well 8, the first test in Texas, was worked-over and completed as a dual in Oct., 1961. This well is completed in a low-pressure gas sand and a low-pressure oil sand. The gas is used to lower the gradient in the well to allow flow from the oil zone. The low bottom-hole pressure existing in the gas

TABLE 7—INDIVIDUAL TEST DATA FOR UPPER ZONE, WELL NO. 1—LOWER ZONE BLANKED-OFF

Date	Choke Size (in.)	Production Oil (B/D)	Production Gas (Mcf/D)
7-24-60	5/64	7.23	248
10-5-60	5/64	7.80	227
10-18-60	5/64	7.80	227
12-4-60	5/64	7.23	209
1-27-61	3.5/64	6.38	175
5-29-61	3.5/64	6.96	150

TABLE 8—INDIVIDUAL TEST DATA OF LOWER ZONE, WELL NO. 3—UPPER ZONE BLANKED-OFF

Tubing Pressure (psig) Surface	Tubing Pressure (psig) Inlet	Production Condensate (B/D)	Production Gas (Mcf/D)
790	1,466	38.40	726,802
950	1,549	39.41	726,802
1,060	1,835	37.34	708,654
1,250	2,091	32.12	638,787
1,335	2,345	30.06	555,196
1,475	2,517	22.82	454,251
1,600	3,125	12.44	222,078

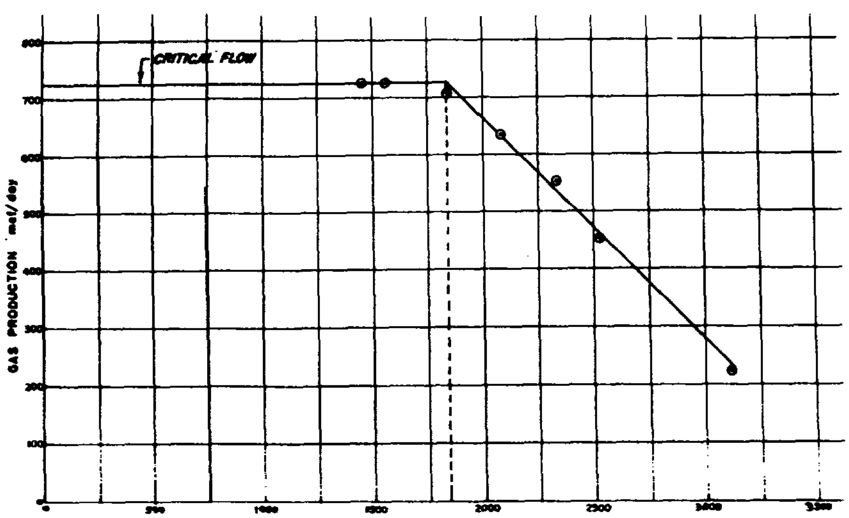

Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

sand will not justify the surface facilities that would be required for the sale of the gas, nor will the low pressure justify the use of this gas in a conventional gas-lift system.

A new check valve received its first subsurface test in Well 8. Results were quite encouraging, and the valve subsequently has been used in other wells. The lower zone in Well 8 was acidized with the new check valve protecting the upper zone. The treatment was successful mechanically, and the check valve functioned perfectly. Maximum differential pressure across the check valve during acidizing was 4,000 psi.

This new check valve is a sleeve-type steel valve incorporating both a metal-to-metal and an O-ring seal. In time, it may replace entirely the resilient-type check valve.

The required packer-leakage test in Well 8 was obtained by blanking-off the upper zone in the orifice head and flowing the upper zone through the casing. The lower zone was open to the tubing. The casing and tubing pressures were recorded simultaneously. This is the method for obtaining a packer-leakage test when there is no packer set above the upper zone. If the upper packer is set, packer-leakage tests can be made by measuring the bottom-hole pressure of one zone while flowing the other. A device is now available which will allow a bottom-hole pressure element to be run with the orifice-head assembly. The shut-in bottom-hole pressure of one zone is measured while the other is open to flow. This type of packer-leakage test should be more realistic than the conventional test where surface pressure fluctuations are observed.

Allocation tests in Well 8 are made by blanking-off the lower zone and measuring the gas produced from the upper zone through the tubing. The two zones are then combined and the increase in gas rate is calculated from the orifice-meter chart. This increase represents the volume of gas produced from the lower zone. All liquids produced are known to have come from the lower zone, as the upper zone produces dry gas. The tubing inlet pressure is measured. The results show that the upper zone is in critical flow. This means that production from the lower zone has no effect on the predetermined rate from the upper zone.

It can be argued that this method of gas measurement is considerably more accurate than the usual method of measuring gas into and out of a conventional, intermitting-type gas-lift well.

Economics

Use of the multiple-completion choke assembly to produce two reservoirs simultaneously through a single flow string results in an initial saving in equipment and rig costs, and in later workover costs, when compared with twin-string duals.

The savings possible cover a wide range. For example, the equipment costs of Well 6 are compared with those of a twin-string dual in the same field, on a comparative-footage basis, in Table 10. This represents a difference of $42,131 and includes neither the saving in rig time nor the considerable saving in workover costs which may result. Anyone who has worked-over a deep twin-string dual in a water location will attest—perhaps grimly—to the costs that can be incurred in such operations.

At the other end of the scale, in the relatively shallow wells, a cost comparison between tubular requirements in three different types of dual completions is shown in Table 11.

Initial completion operations conceivably might result in the tubingless-completion dual costing more than the single-string dual.

Simplicity and flexibility always should be taken into account when planning the system that will produce the most hydrocarbons for the least money.

The wireline expense associated with the simultaneous, one-flow-string method will depend primarily upon operator skill, accessibility of location, depth and testing requirements. This expense will be relatively high for the first month or two, and then will taper off. Wireline costs for the year 1961 in Well 1 have averaged $65 per month. In many wells, as in Well 1, the wireline expense will be more than compensated for by increased production, reduced lifting costs and greater ultimate recovery.

TABLE 10 — TUBULAR-GOODS COST OF TWIN-STRING VS SINGLE-STRING DUAL COMPLETION

	Well "X"	Well No. 6
Conductor	$ 788 (20 in.)	$ 538 (16 in.)
Surface	13,981 (11¾ in.)	11,200 (10¾ in.)
Oil String	61,500 (7⅝ in.)	39,600 (5½ in.)
Tubing	27,000 (2⅜ in.)	11,200 (2⅜ in.)
Wellhead Costs	5,200	3,800
Total	$108,469	$66,338

Acceptance By Regulatory Agencies

Permission to use the multiple-completion choke assembly in Well 1 was granted by the Louisiana Conservation Commission on a six-month basis, and then extended permanently for that particular well. Approval for the other two Kinder wells was obtained after a public hearing. The hearing was necessary because the lower producing sand was unitized and created a diversity of ownership in those wells.

Approval for the other Louisiana installations has been obtained after filing a routine request for permission to dually complete, with the provision that a review of the well be made after a six-month operational period.

In Texas, the Railroad Commission has been somewhat stymied by Statewide Rule 15, which says "No well shall be permitted to produce oil and/or gas from different strata through the same string of casing".

This rule was written some 27 years ago to prevent an operator from indiscriminately opening two or more zones in the same wellbore, and commingling this production without regulation or proper identification as to source.

The Railroad Commission, after a public hearing, granted an exception to Rule 15 in the case of Well 8. It was emphasized at the hearing that the old concept of commingling did not apply to wells equipped with the multiple-completion choke assembly, and that there was no basic difference between this and conventional methods inasmuch as commingling occurred *after* regulation, as it does in any tank battery where surface commingling takes place.

There are really no statutory obstacles to Railroad Commission acceptance of this producing method. Opinion No. 0-2245 concerning "The right of an operator to utilize gas produced from an upper horizon in lifting the oil produced from an oil sand at a lower horizon, without first producing the gas at the surface", was approved on May 20, 1940, by Texas Attorney General Mann and by his Opinion Committee. They ruled as follows: "So long as the proper steps are

TABLE 11—TUBULAR-GOODS COST OF SINGLE-STRING VS TWIN-STRING AND TUBINGLESS COMPLETION

	Twin String			Tubingless			Single String		
	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost
Surface	500	9⅝	$ 1,750	500	9⅝	$1,750	500	9⅝	$ 1,750
Oil String	4,600	7	9,450	9,000	2⅞	7,450	4,600	5½	6,750
Tubing	9,000	2⅜	5,600	None	—	—	4,500	2⅜	2,800
Total			$16,800			$9,200			$11,300

taken to insure against the escape of oil or gas from one stratum into another, we do not believe that the statutes prevent the Commission from permitting the more efficient method of introducing the gas into the tubing below the surface, instead of requiring that the gas first be brought to the surface through a separate string of casing and then reintroduced into the well".

Other Applications

Use of the multiple-completion choke assembly is not limited to the applications that have been described. For example, the device is ideally suited to dual gas wells, and is being used in such wells in Mexico. Other, more specialized, installations are illustrated in Figs. 5 through 10. The single-string dual tubingless completion shown in Fig. 10 must surely represent the final stage in the reduction of initial equipment costs for dual completions.

Operational Suggestions

Following are some suggestions to those who contemplate using the multiple-completion choke assembly.

1. Set tubing with as little compression as possible to facilitate wireline operations.

2. Install the side-door choke in the landing nipple when the tubing is run to permit washing the well around the bottom of the tubing.

3. Pull the side-door choke and clean both zones before running the check-valve assembly, unless the differential in bottom-hole pressures is too great.

4. Use a wireline operator experienced in the operation of the multiple-completion choke assembly. Be sure he has good equipment on the job, including a sensitive weight indicator.

5. If the lower zone is protected by a check valve, do not run the orifice head with a blank in the opening communicating with the lower zone. This is similar to forcing a piston into a closed cylinder containing liquid, and will cause destruction of the O-ring seals on the tube and possible bending of the tube. This situation arises only when the lower zone is the weak zone and requires a check valve. Under these circumstances, when a test is made of the upper zone alone, the O-rings should be left off the tube of the orifice-head assembly. The higher pressure of the upper zone acting against the check valve of the lower zone will prevent flow from the lower zone.

6. Take extra precautions to assure accurate measurement of the fluids produced during tests. This is very important and should be stressed with field personnel.

7. For especially severe service, the metal sleeve-type check valve with an O-ring seal is recommended.

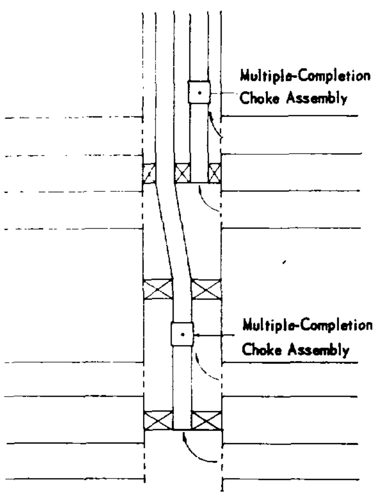

Fig. 5—Two-string quadruple completion.

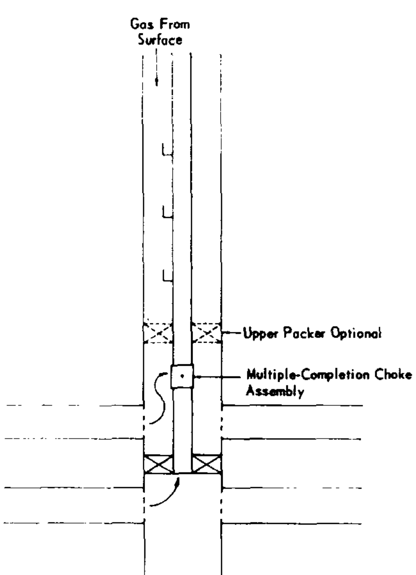

Fig. 6—Gas-lifting two zones with one string of flow valves.

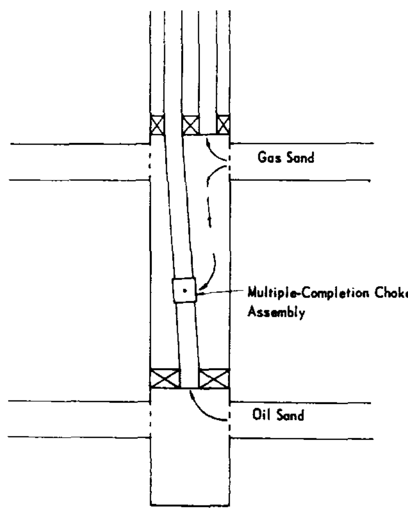

Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

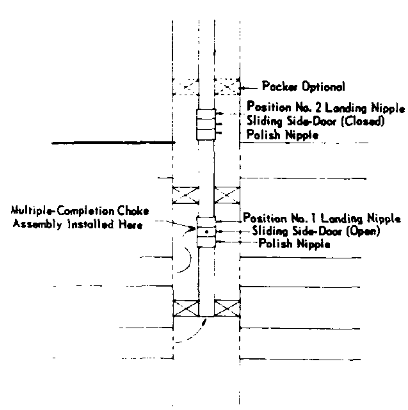

Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

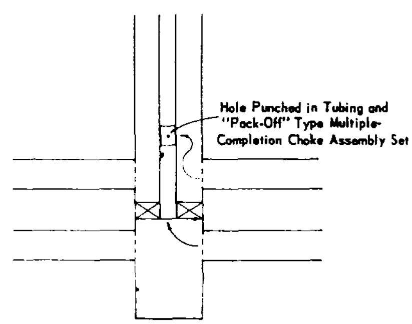

Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

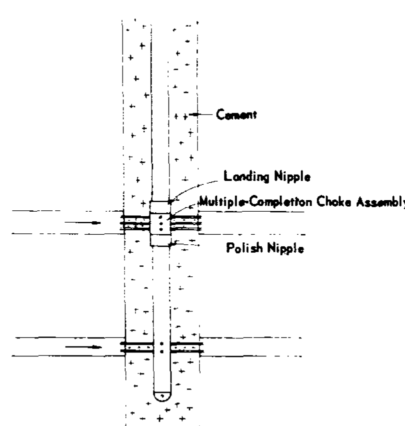

Fig. 10—One-string dual tubingless completion.

Future Development

The future development of the multiple-completion choke assembly and the method of simultaneous production through a single flow string is projected along the following two lines.

1. Surface-recorded bottom-hole pressures will be used to facilitate allocation and packer-leakage tests. A large portion of the wireline work could be eliminated if one had knowledge of the two pressures upstream from the choke and the tubing inlet pressure.

2. Informative material will be presented to state regulatory agencies in an effort to secure general acceptance of the process. This is largely a matter of demonstrating the feasibility of the method, both legally and mechanically, and showing that it will effect conservation and prevent waste.

Conclusions

Simultaneous production of two reservoirs through a single flow string can result in a significant reduction in completion and lifting costs, and will increase current income and ultimate recovery. The multiple-completion choke assembly can be used to maintain separation of the reservoirs and to control the rate of production from each. Test procedures have been developed which provide an acceptable method of determining the contribution from each zone. All requirements imposed by the various regulatory agencies can be satisfied.

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★★★

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This new type dual completion reduces costs, boosts recovery

Unique wireline retrievable tool permits commingling of production downhole, accurate determination of contribution from each zone

By **J. W. Hodges,** Administrative Engineer, Sun Oil Company, Beaumont, Texas

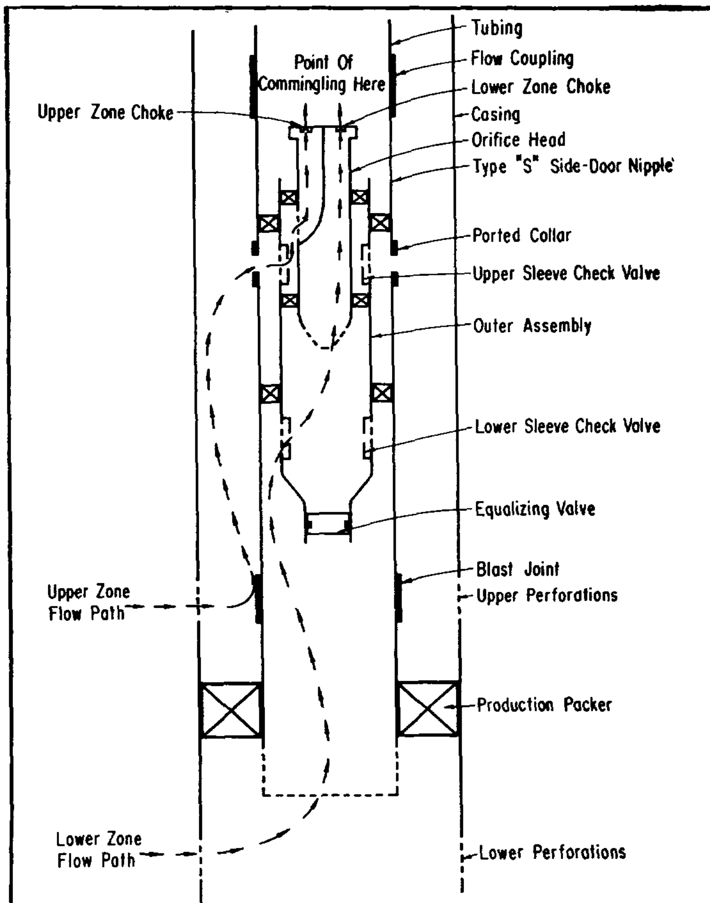


FIGURE 1—Schematic drawing shows how new multiple completion wireline tool works. Note that production is effectively separated until commingled above chokes.

Sun Oil Company has developed and is currently using a new wireline multiple completion tool to produce two separate reservoirs simultaneously through a single tubing string. The multiple completion tool has been successfully installed in a well in Allen Parish, Louisiana since March 1960. Annual gross income from the well has increased $48,400.00, with a net reduction in operating costs. Another tool was set recently in a well in St. Mary Parish. Five additional Sun installations in Louisiana are in progress.

Major advantages in using this tool to commingle production from separate reservoirs in one string of tubing are:

- Excess energy from one zone can be used to lift production from a weaker well.
- Current income can be increased and well costs reduced sharply.
- Completions can be made economically in doubtful looking zones apparently not worth the additional investment required for a twin string dual.
- When completed and commingled with a good well, weak zones can be produced to depletion without artificial lift.

All these factors contribute to an increase in ultimate recovery.

Operation of the downhole commingling tool is shown schematically in Figure 1. The lower zone flows up the tubing, enters the tool through a slotted section in the outer assembly, flows around a resilient check valve and enters the tube of the orifice head assembly where it is choked. Lower zone production then is commingled with upper zone fluid in the tubing above the tool.

The upper zone flows up the casing and into the tubing through a ported collar. It then enters the tool through another slotted section in the outer assembly, flows around the upper resilient check valve into the annulus around the tube, is choked and then commingled with the lower zone.

Pack-off elements maintain separation of the two zones up to the point of regulation. The system thus becomes analagous to surface commingling, as shown in Figure 2, except that the point of pressure reduction is located in the logical place—at the bottom of the well where energy in the released gas can be utilized. This energy is wasted when surface chokes are used.

The multiple completion choke assembly is shown in Figure 3. The outer assembly, shown on the left, is run with wireline tools and is located and locked in a type S side-door choke landing nipple. The resilient check valves, shown opposite the relative positions they occupy within the tool, prevent flow from one zone to the other. The orifice head, shown on

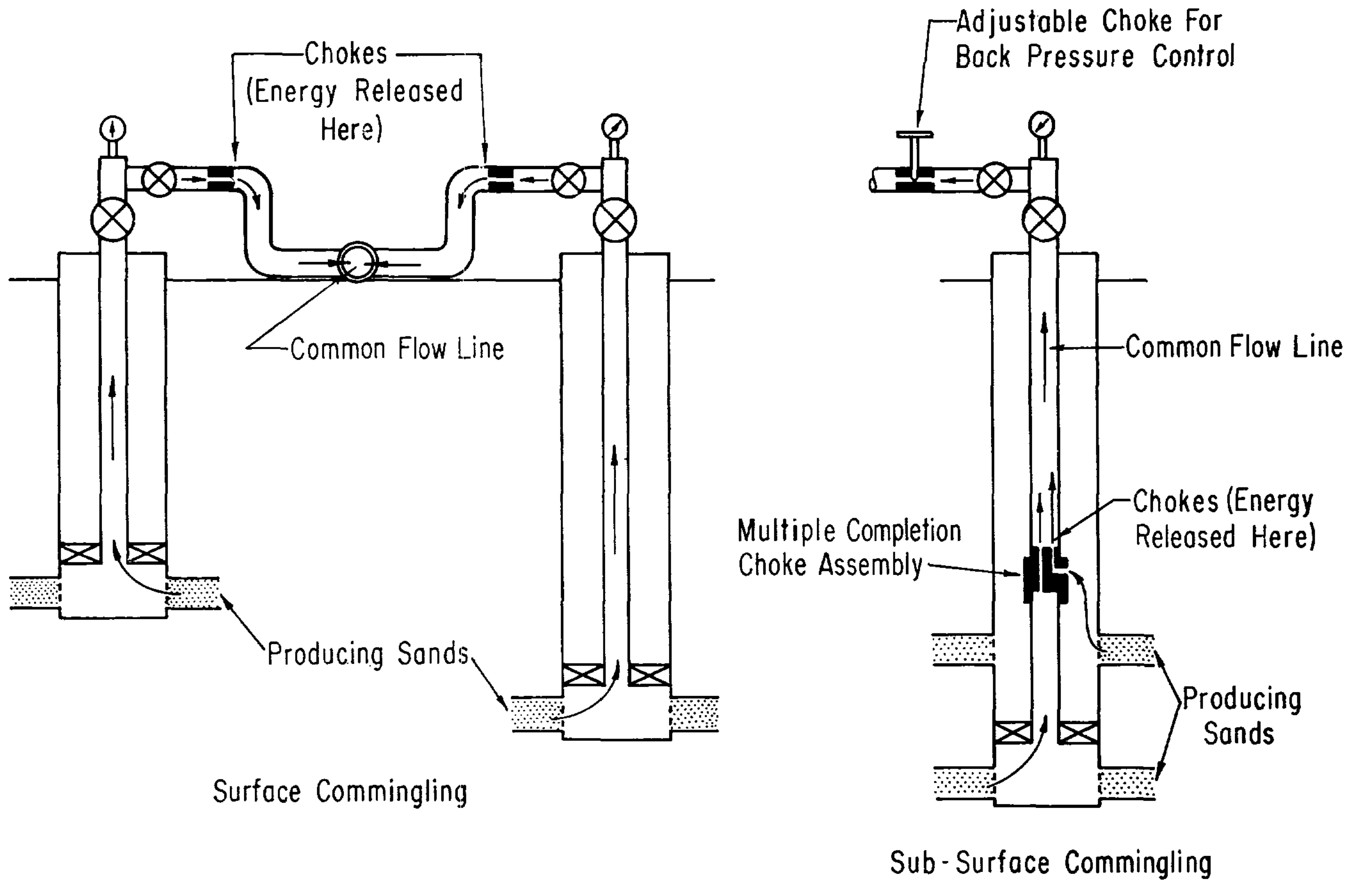


FIGURE 2—Downhole commingling is analoguous to surface commingling except that the pressure reduction is accomplished at the bottom of the hole where energy in released gas can be used.

the right with the two tungsten carbide choke beans, is run separately and is locked in the outer assembly.

Steps involved in installation of the assembly are illustrated in Figure 4. When a choke change is required, the orifice head is pulled leaving the outer assembly in place. The check valves in the outer assembly prevent flow from one zone to the other even with the orifice head removed from the well. Required wireline operations are relatively simple and have become routine.

The well in Allen Parish, prior to installation of the multiple completion choke assembly, was producing as a concentric dual completion with the upper zone flowing in the annulus between the 2⅜-inch tubing and 5½-inch casing and the lower zone flowing through the tubing. The upper zone, a high ratio oil well, is completed through perforations 8,067-70 feet. The lower zone, a gas well, is completed through perforations 8,448-52 feet. The conversion to commingled flow was made with wireline tools by pulling the side-door choke located at 8,000 feet and replacing it with the multiple completion choke assembly.

The subsequent increase in production resulted from decreased gas-liquid ratios and an increase in lower zone productivity. Operating costs were reduced through elimination of the surface heater (by the bottom hole choke effect) and because gas from the lower zone no longer requires compression to enter the sales line. Periodic production and packer leakage tests required by the Louisiana Department of Conservation have been performed on a routine basis. *There has been no evidence of communication between the two reservoirs.*

Hardness of the choke material and location of chokes below paraffin deposition depth have eliminated choke erosion and plugging. This has resulted in accurate determination of the contribution from each zone. Table 1 reflects the consistency of production rates through the 5/64-inch choke serving the upper zone well. The same 5/64-inch choke was used in each test and operated in the well from April 1, 1960 until replaced with a different size choke in January 1961. The choke was not cut when replaced.

The tests were used as a basis for allocating production to each zone, and were obtained by inserting a blank choke bean in the orifice head opening communicated to the lower zone. (This again is analagous to the conventional surface commingling system shown in Figure 2 and is the same thing as closing the wing valve on one of the wells while producing the other on test.) When a stabilized upper zone rate had been established,

the orifice head was round tripped and a stabilized test made with both zones producing. The predetermined rate of gas and liquid production from the upper zone was subtracted from the total. The remainder was allocated to the lower zone.

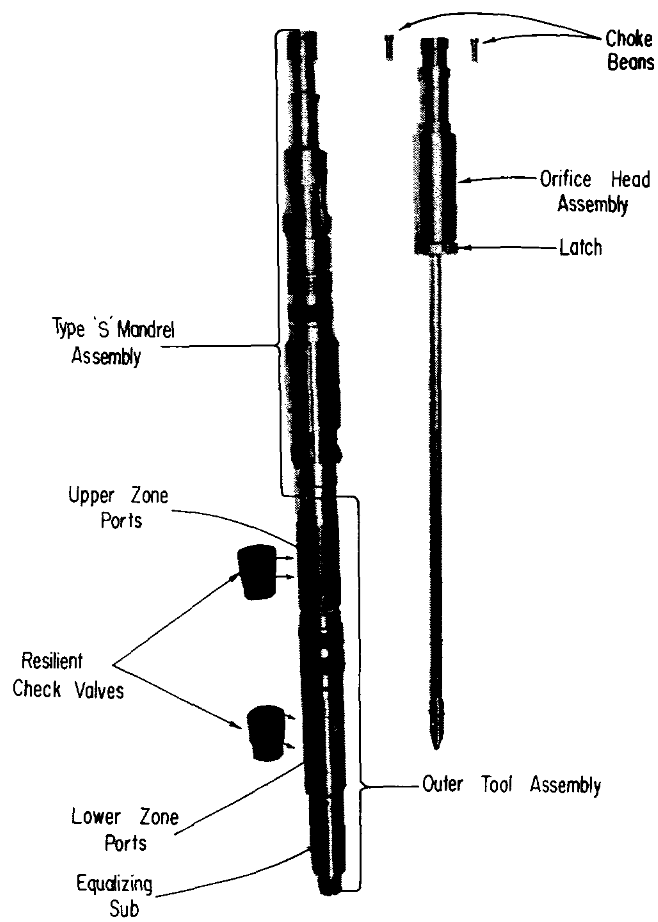
The rate of production from the upper zone is not affected by commingling as flow through the choke is not in the critical range. Flow from the lower zone is in the critical range and can be regulated with a surface choke. Producing characteristics of the two zones determine method of control and test procedures.

Conditions imposed by use of the multiple completion choke assembly afford maximum opportunity for accurate flow rate control. In any system involving commingled production, the accuracy of determining the contribution from each zone depends on accurate flow rate control. The chokes in the multiple completion tool —more resistant to erosion and unaffected by paraffin deposition—will perform more efficiently than surface chokes. The multiple completion tool dual, therefore, will provide for more accurate allocation than can be obtained with conventional surface commingling.

Multiple completion choke beans are undergoing a severe abrasion test in one of Sun's wells in Chambers County, Texas. In an attempt to solve acute problems associated with high pressure well completions, the multiple completion tool has been modified to single zone flow and is being used as a bottom hole choke. Surface tubing pressure of this well has been reduced from 7,300 psi to 4,100 psi.

A high differential type leak, probably a tubing thread leak, which had existed before the installation was made, has been stopped. Production through the choke to date has been 492,000 Mcf of gas and 2,400 barrels of condensate, a total effluent in excess of 24 million pounds. There has been no discernible cutting of the choke.

If this experiment proves the feasibility of pressure reduction as a solution to the problems associated with producing abnormally high pressure wells, hazards to personnel will be reduced and the terrific costs incurred in working over such wells can be avoided.



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The flowing bottom hole pressure of the lower zone is reduced from 6,500 psi to 1,350 psi across the tool. Surface pressure is regulated at 150 psi and can be increased with an adjustable choke, if necessary, to control upper zone production. Tubing pressure immediately above the multiple completion tool can be elevated to approximately 3,250 psi without changing the lower zone rate.

The necessary wire line operations in this deep, high pressure, high temperature, directional well have been performed with relative ease; however, a word of caution is directed to anyone planning to use this tool for the first time: someone with previous experience should be on the job. Dressing and running the assembly would not be a routine operation to an inexperienced person and could jeopardize success of the installation.

The multiple completion tool can be used in a wide range of wells: dual oil; dual oil and gas; dual gas (the tool is ideally adapted to dual gas wells and is being used in that capacity in Mexico); permanent completions; and gas lift installations.

To determine whether the tool has application in any particular well, one must first determine the pressure that will exist at the point of commingling. This will be the controlled surface pressure plus the pressure required to lift the combined fluids to the surface, the latter being essentially a function of gas-liquid ratio,

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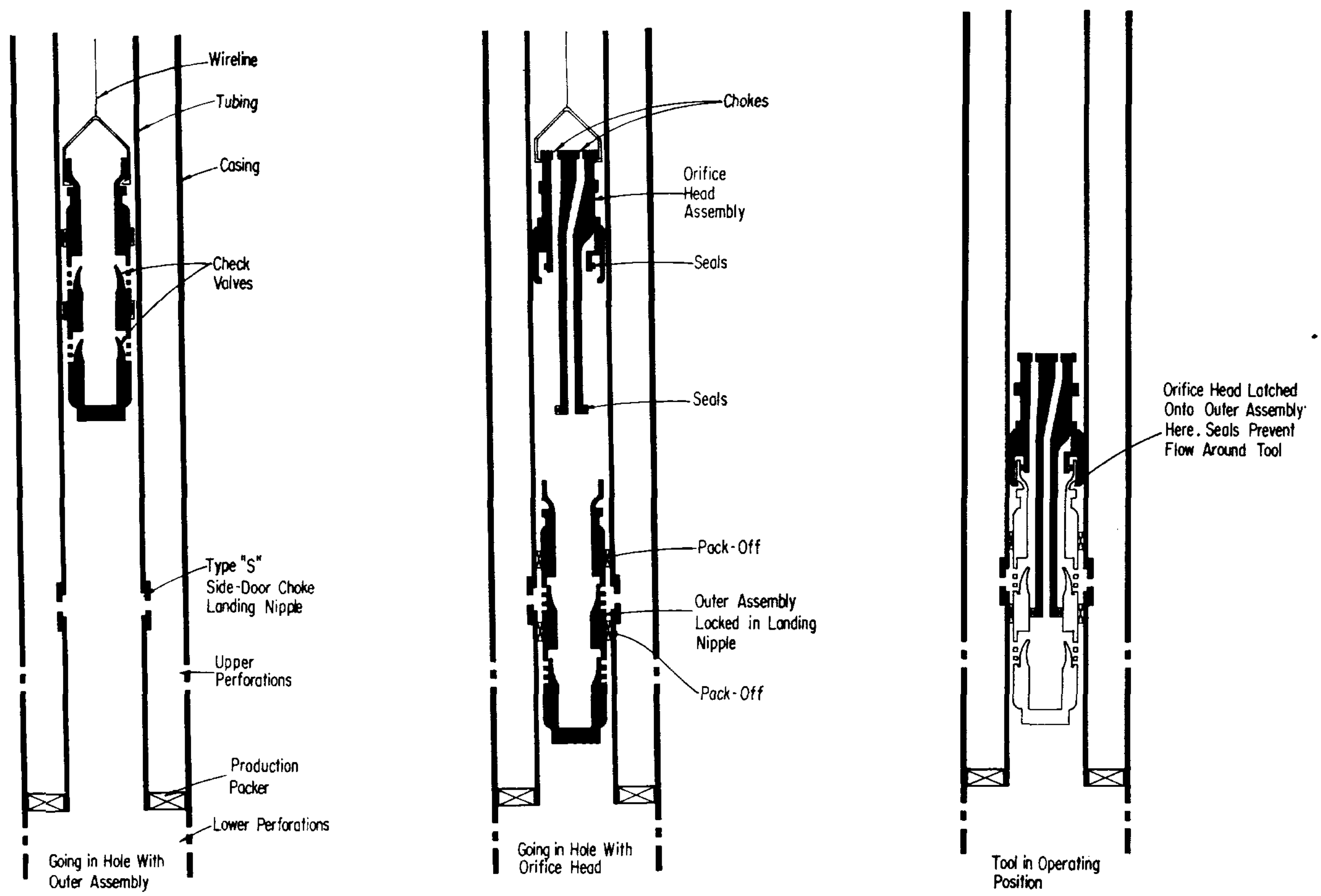

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Field tests of the multiple completion tool have demonstrated it to be a means of increasing current income as well as ultimate recovery at reduced operating costs. This should appeal to all segments of the industry —oil companies, royalty owners and regulatory agencies.

Future development of the multiple completion tool depends to a large extent on acceptance by conservation commissions, as well as the oil industry. Acceptance in turn depends on a thorough understanding of the tool and an appreciation of its potential worth. Some traditional ideas and concepts must be re-examined. There is a great difference between controlled and uncontrolled subsurface commingling. Sun has clearly demonstrated in field tests that wireline tools can be used to separate the production from two reservoirs, to control the rate of production from each and to change the rate of production as required.

The interest and cooperation shown by the Louisiana Department of Conservation has been a material factor in the present stage of development of this new production technique.

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This new type dual completion reduces costs, boosts recovery

Unique wireline retrievable tool permits commingling of production downhole, accurate determination of contribution from each zone

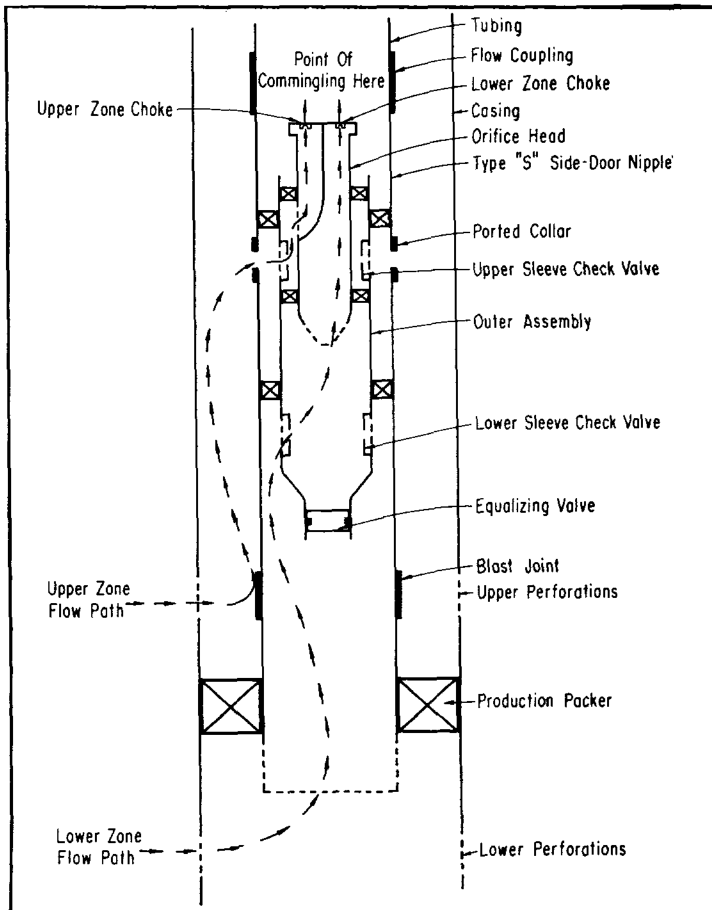

FIGURE 1—Schematic drawing shows how new multiple completion wireline tool works. Note that production is effectively separated until commingled above chokes.

By J. W. Hodges, Administrative Engineer, Sun Oil Company, Beaumont, Texas

Sun Oil Company has developed and is currently using a new wireline multiple completion tool to produce two separate reservoirs simultaneously through a single tubing string. The multiple completion tool has been successfully installed in a well in Allen Parish, Louisiana since March 1960. Annual gross income from the well has increased $48,400.00, with a net reduction in operating costs. Another tool was set recently in a well in St. Mary Parish. Five additional Sun installations in Louisiana are in progress.

Major advantages in using this tool to commingle production from separate reservoirs in one string of tubing are:

- Excess energy from one zone can be used to lift production from a weaker well.
- Current income can be increased and well costs reduced sharply.
- Completions can be made economically in doubtful looking zones apparently not worth the additional investment required for a twin string dual.
- When completed and commingled with a good well, weak zones can be produced to depletion without artificial lift.

All these factors contribute to an increase in ultimate recovery.

Operation of the downhole commingling tool is shown schematically in Figure 1. The lower zone flows up the tubing, enters the tool through a slotted section in the outer assembly, flows around a resilient check valve and enters the tube of the orifice head assembly where it is choked. Lower zone production then is commingled with upper zone fluid in the tubing above the tool.

The upper zone flows up the casing and into the tubing through a ported collar. It then enters the tool through another slotted section in the outer assembly, flows around the upper resilient check valve into the annulus around the tube, is choked and then commingled with the lower zone.

Pack-off elements maintain separation of the two zones up to the point of regulation. The system thus becomes analagous to surface commingling, as shown in Figure 2, except that the point of pressure reduction is located in the logical place—at the bottom of the well where energy in the released gas can be utilized. This energy is wasted when surface chokes are used.

The multiple completion choke assembly is shown in Figure 3. The outer assembly, shown on the left, is run with wireline tools and is located and locked in a type S side-door choke landing nipple. The resilient check valves, shown opposite the relative positions they occupy within the tool, prevent flow from one zone to the other. The orifice head, shown on

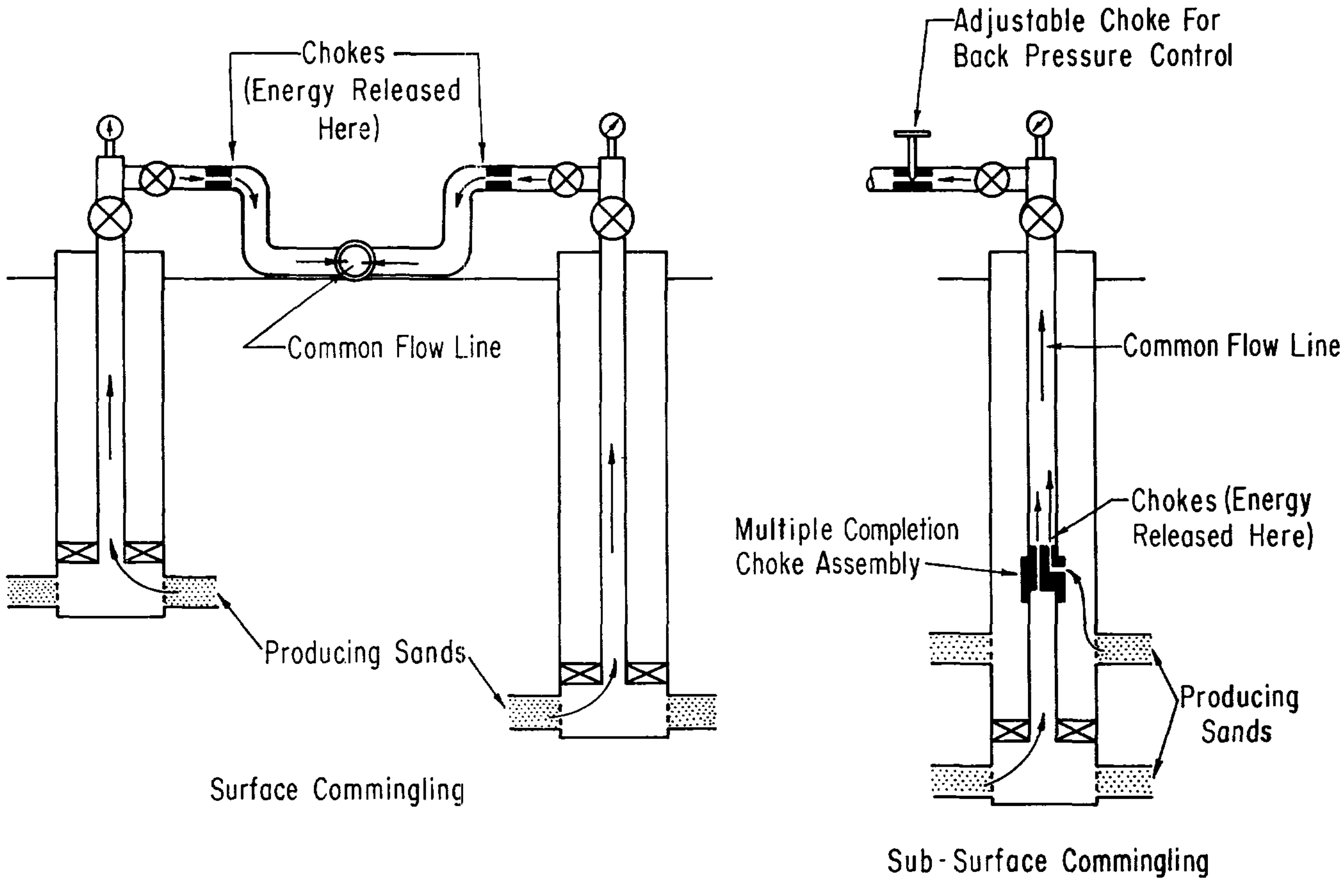

FIGURE 2—Downhole commingling is analoguous to surface commingling except that the pressure reduction is accomplished at the bottom of the hole where energy in released gas can be used.

the right with the two tungsten carbide choke beans, is run separately and is locked in the outer assembly.

Steps involved in installation of the assembly are illustrated in Figure 4. When a choke change is required, the orifice head is pulled leaving the outer assembly in place. The check valves in the outer assembly prevent flow from one zone to the other even with the orifice head removed from the well. Required wireline operations are relatively simple and have become routine.

The well in Allen Parish, prior to installation of the multiple completion choke assembly, was producing as a concentric dual completion with the upper zone flowing in the annulus between the 2⅜-inch tubing and 5½-inch casing and the lower zone flowing through the tubing. The upper zone, a high ratio oil well, is completed through perforations 8,067-70 feet. The lower zone, a gas well, is completed through perforations 8,448-52 feet. The conversion to commingled flow was made with wireline tools by pulling the side-door choke located at 8,000 feet and replacing it with the multiple completion choke assembly.

The subsequent increase in production resulted from decreased gas-liquid ratios and an increase in lower zone productivity. Operating costs were reduced through elimination of the surface heater (by the bottom hole choke effect) and because gas from the lower zone no longer requires compression to enter the sales line. Periodic production and packer leakage tests required by the Louisiana Department of Conservation have been performed on a routine basis. *There has been no evidence of communication between the two reservoirs.*

Hardness of the choke material and location of chokes below paraffin deposition depth have eliminated choke erosion and plugging. This has resulted in accurate determination of the contribution from each zone. Table 1 reflects the consistency of production rates through the ⁵⁄₆₄-inch choke serving the upper zone well. The same ⁵⁄₆₄-inch choke was used in each test and operated in the well from April 1, 1960 until replaced with a different size choke in January 1961. The choke was not cut when replaced.

The tests were used as a basis for allocating production to each zone, and were obtained by inserting a blank choke bean in the orifice head opening communicated to the lower zone. (This again is analagous to the conventional surface commingling system shown in Figure 2 and is the same thing as closing the wing valve on one of the wells while producing the other on test.) When a stabilized upper zone rate had been established,

the orifice head was round tripped and a stabilized test made with both zones producing. The predetermined rate of gas and liquid production from the upper zone was subtracted from the total. The remainder was allocated to the lower zone.

The rate of production from the upper zone is not affected by commingling as flow through the choke is not in the critical range. Flow from the lower zone is in the critical range and can be regulated with a surface choke. Producing characteristics of the two zones determine method of control and test procedures.

Conditions imposed by use of the multiple completion choke assembly afford maximum opportunity for accurate flow rate control. In any system involving commingled production, the accuracy of determining the contribution from each zone depends on accurate flow rate control. The chokes in the multiple completion tool —more resistant to erosion and unaffected by paraffin deposition—will perform more efficiently than surface chokes. The multiple completion tool dual, therefore, will provide for more accurate allocation than can be obtained with conventional surface commingling.

Multiple completion choke beans are undergoing a severe abrasion test in one of Sun's wells in Chambers County, Texas. In an attempt to solve acute problems associated with high pressure well completions, the multiple completion tool has been modified to single zone flow and is being used as a bottom hole choke. Surface tubing pressure of this well has been reduced from 7,300 psi to 4,100 psi.

A high differential type leak, probably a tubing thread leak, which had existed before the installation was made, has been stopped. Production through the choke to date has been 492,000 Mcf of gas and 2,400 barrels of condensate, a total effluent in excess of 24 million pounds. There has been no discernible cutting of the choke.

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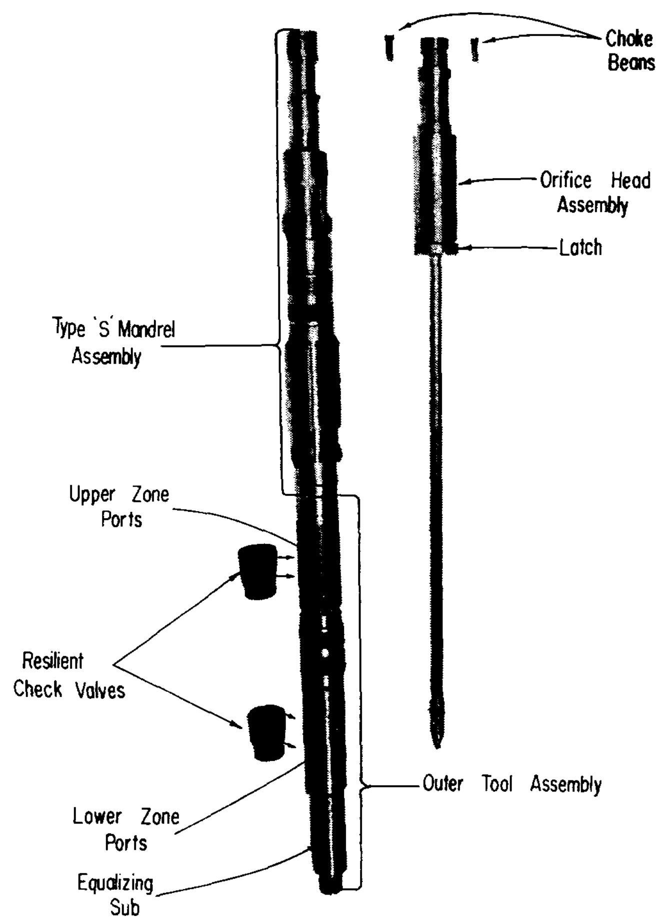

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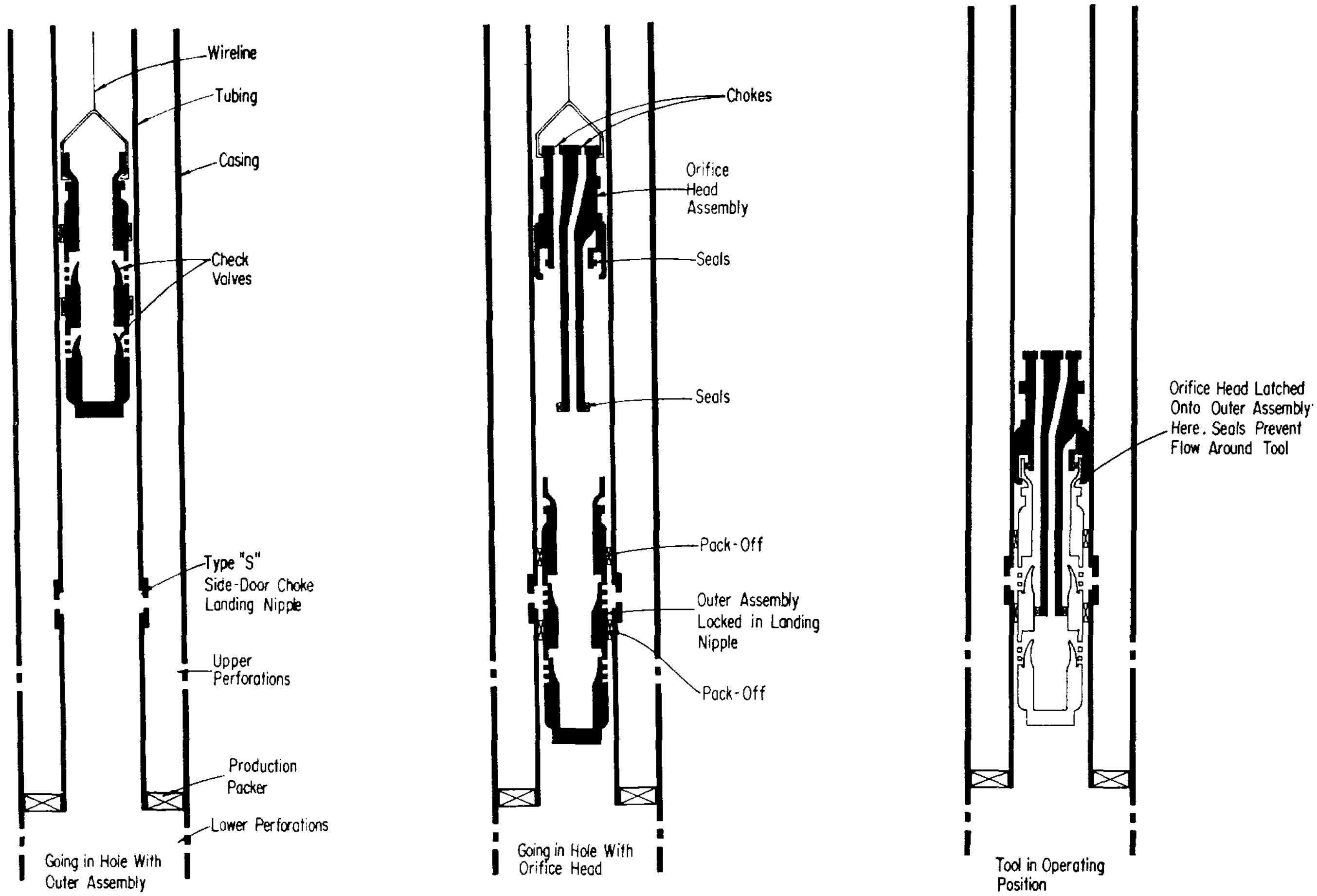

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New Tool Permits Simultaneous Production of Two Reservoirs Through the Same Flow String

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SUN OIL CO.
BEAUMONT, TEX.

Abstract

The constant search for methods to increase the efficiency of production systems and to reduce operating costs has led to the development of a wireline tool which makes it possible to produce and control two separate reservoirs through a single string of tubing. This paper is a progress report of the experience one company has gained with this tool in eight of its dually completed wells in Louisiana and Texas. Field tests have clearly demonstrated that this device can be used to maintain separation of production from two reservoirs, to control and determine the rate of production from each, and to change the rate of production as required. The advantages in simultaneous one-string multiple completions are enumerated, and various applications of the method are discussed.

Introduction

It is now almost standard operating procedure to complete wells in more than one zone wherever possible, with the great majority of these multiples being dual completions. This is a sign of the times. Saving must be accomplished wherever possible; however, there is no need to expand on this theme. All are painfully aware of the economic conditions within the industry. It is sufficient to say that the practice of multiple completions is here to stay and is becoming more popular every day. The only question is whether or not the practice has evolved into its most acceptable form.

The earlier duals were the concentric type, with one zone producing through the tubing and the other through the tubing-casing annulus. This method is still practiced to a large degree. It is popular because it is relatively inexpensive. Unfortunately, it has some rather severe limitations, with which the reader undoubtedly is familiar.

The twin-string dual is an improvement over the concentric in the sense that many of the problems associated with the concentric have been solved. The objectionable features of the twin-string dual are the high cost of equipping the well with an extra string of tubing, plus accessories, and the complications brought on by cramming all this tubing into one string of casing.

Still another type of multiple is the tubingless completion, wherein two or more small casing strings are cemented in place and subsequent operations performed with miniaturized equipment.

The purpose of this paper is to present a different concept in multiple completion—the simultaneous production of separate reservoirs in a single flow string. This method combines the simplicity and low cost of the concentric with the flexibility of the twin-string dual. In addition, it provides the unique advantage of prolonging natural flow from a low-pressure zone by combining its production with the fluids produced from a higher-pressure zone. The wireline tool which makes this method possible is the multiple-completion choke assembly.

Construction and Operation of the Multiple-Completion Choke Assembly

Fig. 1 shows a well properly equipped to receive a multiple-completion choke assembly. A conventional packer separates the two producing zones. The upper packer is optional. A side-door choke landing-nipple hookup is located in the tubing

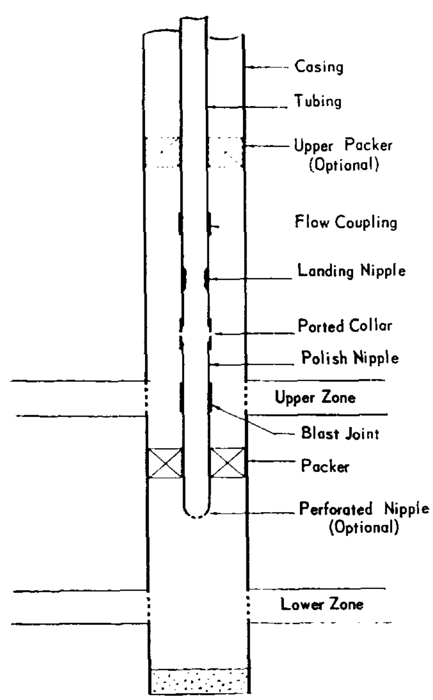

Fig. 1—Well properly equipped for multiple-completion choke assembly.

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string above the lower packer. The multiple-completion choke assembly will be locked in this landing nipple. Normally located a joint or two above the upper zone, the position of the landing-nipple hookup can be varied to suit well conditions. For example, where the two zones are widely separated, it might be placed just above the lower packer to facilitate bottom-hole pressure tests of the lower zone.

The tool consists of two separate assemblies. The outer assembly, which is run independently and locked in the landing nipple, contains the check valves and packing seals which prevent flow from one zone to the other. In practice, however, only one check valve is usually required and is installed to protect the zone with the lower pressure.

The orifice-head assembly, which carries the tungsten-carbide choke beans, is run separately and is seated and locked in the outer assembly. The method of running each section is illustrated in Fig. 2.

Fig. 3 is a schematic drawing which shows more clearly how the device works. Production from the lower zone enters the assembly through a slotted section, flows around a resilient sleeve-type check valve, enters, and flows through the tube of the orifice-head assembly; it is choked and—now regulated—flows into the tubing. Produced fluids from the upper zone enter the casing opposite a blast joint on the tubing, flow through the ported collar of the side-door choke landing-nipple hookup, through the upper slotted secion, around the upper check valve, into the annulus surrounding the tube and through the upper-zone choke bean into the tubing. Here the two controlled flow streams, which have been kept separate up to this point, combine and flow to the surface.

Tubing Inlet Pressure

The pressure in the tubing at the junction of the two streams will be the minimum pressure required to lift the combined fluids to the surface (at zero surface pressure) and will be determined essentially by the gas-liquid ratio, production rate and tubing size. This pressure, which will hereafter be referred to as the "tubing inlet pressure", is of particular interest because of its importance in the application of the multiple-completion choke assembly. For example, suppose that investigation is being made into the possibility of using the assembly in a two-zone oil well with characteristics as tabulated in Table 1.

The combined production rate is 160 B/D of liquid (including salt water) and 87 Mcf/D of gas. The combined gas-liquid ratio is 543 cu ft/bbl. With a multiple-completion choke assembly set at 6,500 ft in 2⅜-in. OD tubing, it can be determined from published depth-pressure gradient curves[1] that the tubing inlet pressure will be approximately 850 psi.

The upper zone, with a productivity index of 0.5, will produce 96 B/D of liquid with a flowing bottom-hole pressure of approximately 1,308 psi. Since the flowing bottom-hole pressure of the weaker zone is greater than the tubing inlet pressure at the desired rate of production, this well can be produced by natural flow with a multiple-completion choke assembly. Natural flow will be maintained so long as the flowing bottom-hole pressure of the weaker zone (in this example, the upper zone) exceeds the tubing inlet pressure. At some point in the life of the upper zone, however, conditions favorable for natural flow *as a single completion* would no longer prevail. In other words, if it were being produced independently, some form of artificial lift would be required. The requirement is postponed because of the availability of the gas from the lower zone. When the lower zone can no longer "carry" the upper, a single set of flow valves can be run to produce both zones through the multiple-completion choke assembly.

TABLE 1—WELL DATA USED IN EVALUATING APPLICATION OF MULTIPLE-COMPLETION TOOL

	Upper Zone	Lower Zone
Producing Depths (ft)	6,600	7,200
Static BHP (psi)	1,500	3,400
Productivity Index (B/D/psi drop)	0.5	1.0
Oil Produced (B/D)	56	64
Salt Water Produced (B/D)	40	None
Gas Produced (Mcf/D)	39	48
Gas-Liquid Ratio	406	750

Allocation of Production

Allocation of fluids produced from each zone is based on a separate, individual zone test. To obtain such a test, the orifice-head assembly is removed from the check-valve assembly and brought to the surface with conventional wireline tools. (Removal of

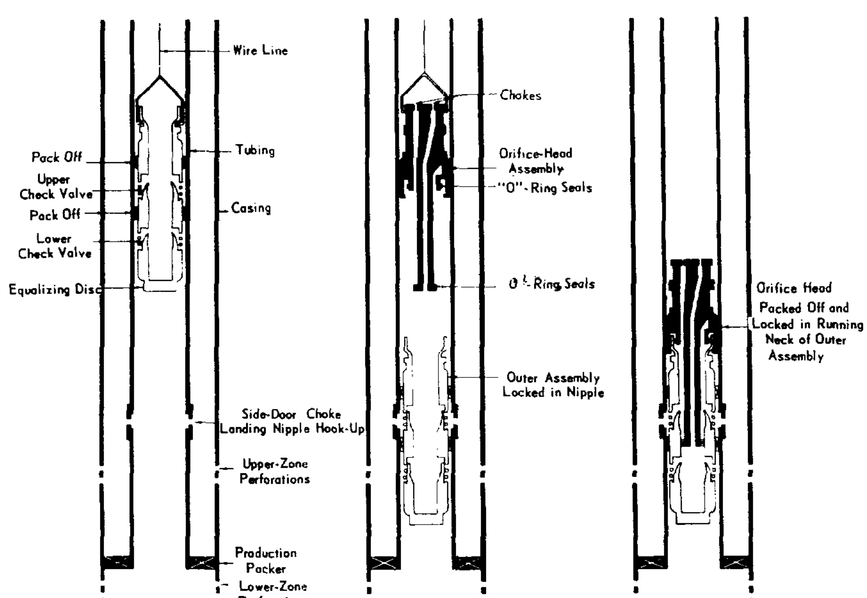

Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

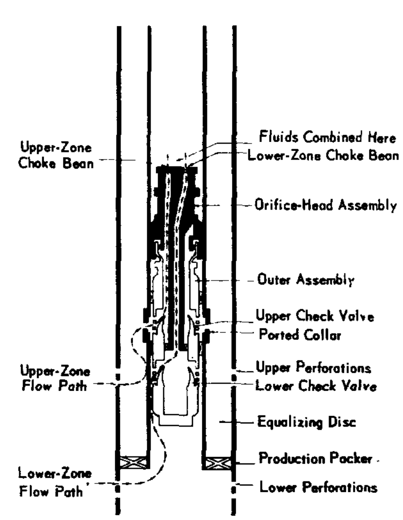

Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

the orifice head does not result in interzone flow, as the check-valve assembly remains in the well.) If the lower zone is to be tested, a blank bean is inserted in the opening in the orifice head communicating with the flow path of the upper zone. A choke bean, properly sized[1] to produce the desired volume of fluid from the lower zone, is placed in the opposite side of the orifice head. The orifice head is then lowered into the well, and landed and locked in the check-valve assembly. The upper zone cannot flow because of the blank choke bean. Produced fluids from the lower zone are measured into conventional surface facilities until a stabilized 24-hour test is obtained. The orifice head is again removed from the well. The blank bean is replaced with a production bean, and the assembly is returned to its operating position in the well. A stabilized test of the combined fluids produced is obtained. The predetermined rate from the lower zone is subtracted from the combined total, with the difference assigned to the upper zone.

The test procedure used will be determined by the flow conditions present in the well—specifically, whether or not one of the zones is in critical flow. A stream is said to be in critical flow when alterations in pressure downstream from an orifice do not affect the rate of flow through the orifice. The critical point occurs when the downstream pressure is 53 per cent of the upstream pressure. The significance of this phenomenon in the operation of the multiple-completion choke assembly is that, if one of the zones is in critical flow and the other is not, the zone not in critical flow can be regulated with a surface control without affecting the rate from the other. In the well described earlier, for example, if the tubing inlet pressure is not allowed to exceed approximately 1,765 psi (53 per cent of 3,336 psi), the rate from the lower zone will not be affected. In other words, back-pressure at the surface can be increased to the point of actually shutting-in the upper zone, with no effect on the rate from the lower zone.

In any well where two reservoirs are being produced simultaneously through the multiple-completion choke assembly, one of the following three conditions will exist: (1) one zone will be in critical flow; (2) neither zone will be in critical flow; or (3) both zones will be in critical flow. The method of testing for allocation will depend upon which one of these conditions exists.

The exact value of the critical P_2/P_1 ratio, whether it be 53 per cent or some other value, is of no particular concern. The ratio is not used quantitatively. As a matter of interest, however, in the wells where this critical point has been observed, the value has appeared reasonably close to 53 per cent.

The exact point of critical flow can be determined by changing the surface tubing pressure with an adjustable choke, measuring the rate of flow into conventional test facilities and observing the effect of the back-pressure changes.

At the same time, the tubing inlet pressure is measured with a bottom-hole pressure gauge. For example, tests run on a certain zone in a dual completion might result in the data shown in Table 2.

These data show the stream is going into critical flow between a tubing inlet pressure of 1,050 and 825 psi. This point can be determined more precisely if the results are shown graphically, as will be illustrated later in actual well tests.

A predetermined rate for this particular zone on a specific choke size for this range of tubing inlet pressures has now been established. It makes no difference what effect, if any, the second zone may have on the tubing inlet pressure in the well. Because this pressure can be determined, the rate from the first zone will be known. The difference is then assigned to the zone not tested individually, usually the lower-pressure zone.

If each zone can produce its allowable independently of the other, there may be some reason to test each separately. This procedure, of course, will require additional wireline work and is not essential in determining the production from each zone. The method has been used occasionally to demonstrate the consistency of flow-rate control possible with the choke beans in the tool.

Summarizing, production tests will follow one of two patterns. If either or both of the two zones is in critical flow when combined, a 24-hour stabilized test of the zone with the higher pressure is obtained. Back-pressure is not adjusted during this test. Following this, both zones are combined and tested for 24 hours at a stabilized rate. The difference in production is known to have come from the zone not tested singly.

If neither of the zones is in critical flow, the zone with the higher pressure is tested individually. The surface pressure is varied and the stabilized rates of production at the various back-pressures are measured. Tubing inlet pressure is recorded with a bottom-hole pressure gauge. This test predetermines the rate to be expected from this zone during periods of combined flow. The rate from the other zone will be determined by difference.

TABLE 2—CRITICAL FLOW DATA

Surface Tubing Pressure (psi)	Tubing Inlet Pressure (psi)	Liquid Rate (B/D)
700	1,300	50
500	1,050	55
300	825	60
100	600	60

[1]References given at end of paper.

Use Of The Tool In Gas Lifting

The multiple-completion choke assembly, when used as a gas-lift device, is in effect a single-point injection, retrievable flow valve utilizing gas supplied directly from the formation at maximum efficiency. An expert in gas-lift technology, in discussing conventional gas-lift systems,[2] has made the following pertinent observations.

> Which flow process, continuous or intermittent, will yield the greatest amount of produced stock-tank liquid for the least amount of injected gas at the available pressures? The continuous-flow process, if properly instituted, should be inherently more efficient than that of intermittent flow. The gas is put to work as needed and the high dissipation of initial energy in overcoming starting inertia is largely absent. Also, the external work done by the gas is negligible. The fact is, however, that maximum efficiency in the continuous-flow process can only be realized by putting the gas to work as soon as possible. This means high injection pressures at moderate depths. Because the high injection pressures necessary for maximum efficiency are seldom available, it has been found in practice that the intermittent-flow process is frequently more efficient than that of continuous flow, for wells that produce moderate amounts of liquid.
>
> It is significant to point out here that the Phillips paper, previously referred to, lists data from some 34 flowing wells and 16 gas-lift wells (continuous flow). The thermodynamic flow efficiency for the flowing wells was on the order of 85 to 95 per cent, whereas the gas-lift wells were mainly of the order of 40-60 per cent. There is no reason why continuous-flow gas-lift wells should not closely approximate the efficiency of naturally flowing wells, if the installations are correctly designed.
>
> It is recognized that the high-pressure requirements for maximum efficient operations is definitely a limiting factor in any practical well installation. It is most important to recognize that, as injection pressures are decreased below the optimum, the flow efficiency

Well No. 2

Well 2 was completed in May, 1961. The upper zone on drill-stem test was judged to be noncommercial but did produce some oil. This is a situation frequently confronting an operator. A zone looks doubtful on an electric log and a drill-stem test is not conclusive—should he make a single or dual completion? It is a perplexing question. The great expense involved in twin-string duals will not often justify a thorough evaluation of these doubtful zones. On the other hand, he may be passing up a commercial reserve. The multiple-completion choke assembly can be used to good advantage in this situation. Doubtful producing horizons can be fully evaluated at low additional cost and, when combined with good producers, can be depleted without artificial lift. This will result in the recovery of more oil and more gas.

Well 2 is a deep, directionally drilled, high-pressure, high-temperature well—a water location—and provided quite a test for the tool. The wireline operations in this well, however, have gone quite smoothly.

Well No. 3

Well 3 was originally a single-completion oil well. In June, 1961, the oil zone was dualled with a deeper sand productive of gas and condensate.

Table 8 gives the results of single-zone tests of the lower zone; Fig. 4 is a graphic representation of these data. Note that the well goes into critical flow at a tubing inlet pressure of 1,835 psi, or 55 per cent of the upstream pressure of approximately 3,300 psi.

After the tests of the lower zone were concluded, the upper zone was tested and then the two zones were combined. The tubing inlet pressure at 7,550 ft was measured with a bottom-hole pressure gauge and found to be 1,720 psi with a surface tubing pressure of 1,100 psi. As a check, the depth-pressure gradient curves were used to determine the tubing inlet pressure under these conditions of flow. This value was interpolated to be 1,650 psi. The lower zone is in critical flow under these conditions. This means that the predetermined rate of production of the lower zone is not affected by combining with the upper.

Well No. 4

Well 4, a water location, was completed in June, 1961. The upper zone is only 8-ft thick and would not justify the additional cost of a twin-string dual.

Production tests of the lower zone with a 4.5/64-in. choke bean in the orifice head were made as shown in Table 9.

These tests show that the well goes out of critical flow when the surface pressure is increased manually above 250 psi. Plotting oil rate vs tubing pressure locates the critical point at 875 psi.

Following these tests, the orifice head was pulled and run back with the lower zone blanked and a 4.5/64-in. choke bean controlling production from the upper zone. On stabilized test in critical flow, the upper zone produced 152 BOPD (neither zone produces salt water) with a gas-oil ratio of 720 cu ft/bbl.

The orifice head was then pulled and returned with each zone open to a 4.5/64-in. choke bean. Combined production was gauged at 311 BOPD, a good check with the individual zone tests (157 and 152, a total of 309 BOPD).

TABLE 9—WELL DATA, LOWER ZONE, WELL NO. 4

Oil Production (B/D)	Gas-Oil Ratio (cu ft/bbl)	Surface Tubing Pressure (psi)
156	827	150
158	919	150
157	936	250
149	905	975
133	972	1,075
122	957	1,200
100	900	1,450

Well No. 5 Through 7

Well 5 was a singly-completed, deficient oil well when it was dually-completed in Aug., 1961, with a gas zone. The oil zone was not good enough to support a twin-string completion and would have been abandoned had not the multiple-completion choke assembly been available.

Well 6, a water location, was completed in Aug., 1961, and has been produced without incident.

Well 7, another water location, was completed in Aug., 1961. Tests show that both zones are in critical flow. Each zone was tested separately. The lower zone made 65 BOPD, and the upper zone was tested at 71 BOPD. When combined, the two zones produced 132 BOPD.

Well No. 8

Well 8, the first test in Texas, was worked-over and completed as a dual in Oct., 1961. This well is completed in a low-pressure gas sand and a low-pressure oil sand. The gas is used to lower the gradient in the well to allow flow from the oil zone. The low bottom-hole pressure existing in the gas

TABLE 7—INDIVIDUAL TEST DATA FOR UPPER ZONE, WELL NO. 1—LOWER ZONE BLANKED-OFF

Date	Choke Size (in.)	Production: Oil (B/D)	Production: Gas (Mcf/D)
7-24-60	5/64	7.23	248
10-5-60	5/64	7.80	227
10-18-60	5/64	7.80	227
12-4-60	5/64	7.23	209
1-27-61	3.5/64	6.38	175
5-29-61	3.5/64	6.96	150

TABLE 8—INDIVIDUAL TEST DATA OF LOWER ZONE, WELL NO. 3—UPPER ZONE BLANKED-OFF

Tubing Pressure (psig)		Production	
Surface	Inlet	Condensate (B/D)	Gas (Mcf/D)
790	1,466	38.40	726,802
950	1,549	39.41	726,802
1,060	1,835	37.34	708,654
1,250	2,091	32.12	638,787
1,335	2,345	30.06	555,196
1,475	2,517	22.82	454,251
1,600	3,125	12.44	222,078

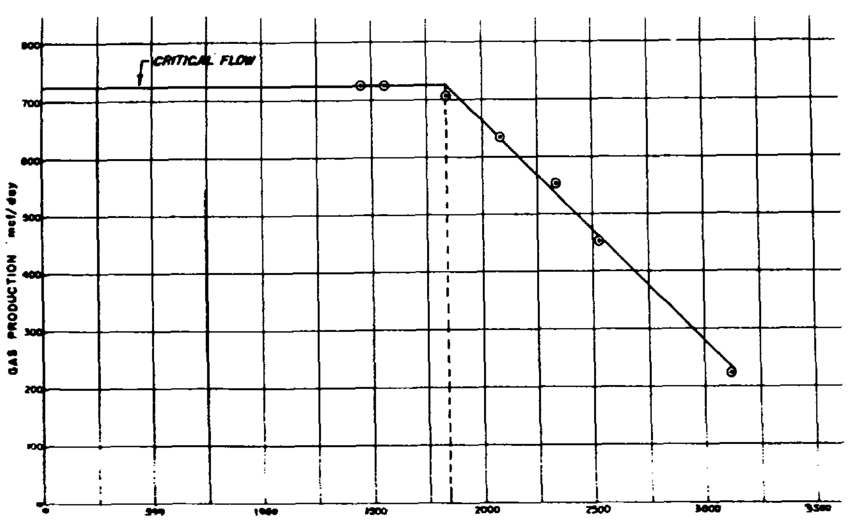

Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

sand will not justify the surface facilities that would be required for the sale of the gas, nor will the low pressure justify the use of this gas in a conventional gas-lift system.

A new check valve received its first subsurface test in Well 8. Results were quite encouraging, and the valve subsequently has been used in other wells. The lower zone in Well 8 was acidized with the new check valve protecting the upper zone. The treatment was successful mechanically, and the check valve functioned perfectly. Maximum differential pressure across the check valve during acidizing was 4,000 psi.

This new check valve is a sleeve-type steel valve incorporating both a metal-to-metal and an O-ring seal. In time, it may replace entirely the resilient-type check valve.

The required packer-leakage test in Well 8 was obtained by blanking-off the upper zone in the orifice head and flowing the upper zone through the casing. The lower zone was open to the tubing. The casing and tubing pressures were recorded simultaneously. This is the method for obtaining a packer-leakage test when there is no packer set above the upper zone. If the upper packer is set, packer-leakage tests can be made by measuring the bottom-hole pressure of one zone while flowing the other. A device is now available which will allow a bottom-hole pressure element to be run with the orifice-head assembly. The shut-in bottom-hole pressure of one zone is measured while the other is open to flow. This type of packer-leakage test should be more realistic than the conventional test where surface pressure fluctuations are observed.

Allocation tests in Well 8 are made by blanking-off the lower zone and measuring the gas produced from the upper zone through the tubing. The two zones are then combined and the increase in gas rate is calculated from the orifice-meter chart. This increase represents the volume of gas produced from the lower zone. All liquids produced are known to have come from the lower zone, as the upper zone produces dry gas. The tubing inlet pressure is measured. The results show that the upper zone is in critical flow. This means that production from the lower zone has no effect on the predetermined rate from the upper zone.

It can be argued that this method of gas measurement is considerably more accurate than the usual method of measuring gas into and out of a conventional, intermitting-type gas-lift well.

Economics

Use of the multiple-completion choke assembly to produce two reservoirs simultaneously through a single flow string results in an initial saving in equipment and rig costs, and in later workover costs, when compared with twin-string duals.

The savings possible cover a wide range. For example, the equipment costs of Well 6 are compared with those of a twin-string dual in the same field, on a comparative-footage basis, in Table 10. This represents a difference of $42,131 and includes neither the saving in rig time nor the considerable saving in workover costs which may result. Anyone who has worked-over a deep twin-string dual in a water location will attest—perhaps grimly—to the costs that can be incurred in such operations.

At the other end of the scale, in the relatively shallow wells, a cost comparison between tubular requirements in three different types of dual completions is shown in Table 11.

Initial completion operations conceivably might result in the tubingless-completion dual costing more than the single-string dual.

Simplicity and flexibility always should be taken into account when planning the system that will produce the most hydrocarbons for the least money.

The wireline expense associated with the simultaneous, one-flow-string method will depend primarily upon operator skill, accessibility of location, depth and testing requirements. This expense will be relatively high for the first month or two, and then will taper off. Wireline costs for the year 1961 in Well 1 have averaged $65 per month. In many wells, as in Well 1, the wireline expense will be more than compensated for by increased production, reduced lifting costs and greater ultimate recovery.

TABLE 10 — TUBULAR-GOODS COST OF TWIN-STRING VS SINGLE-STRING DUAL COMPLETION

	Well "X"	Well No. 6
Conductor	$ 788 (20 in.)	$ 538 (16 in.)
Surface	13,981 (11¾ in.)	11,200 (10¾ in.)
Oil String	61,500 (7⅝ in.)	39,600 (5½ in.)
Tubing	27,000 (2⅜ in.)	11,200 (2⅜ in.)
Wellhead Costs	5,200	3,800
Total	$108,469	$66,338

Acceptance By Regulatory Agencies

Permission to use the multiple-completion choke assembly in Well 1 was granted by the Louisiana Conservation Commission on a six-month basis, and then extended permanently for that particular well. Approval for the other two Kinder wells was obtained after a public hearing. The hearing was necessary because the lower producing sand was unitized and created a diversity of ownership in those wells.

Approval for the other Louisiana installations has been obtained after filing a routine request for permission to dually complete, with the provision that a review of the well be made after a six-month operational period.

In Texas, the Railroad Commission has been somewhat stymied by Statewide Rule 15, which says "No well shall be permitted to produce oil and/or gas from different strata through the same string of casing".

This rule was written some 27 years ago to prevent an operator from indiscriminately opening two or more zones in the same wellbore, and commingling this production without regulation or proper identification as to source.

The Railroad Commission, after a public hearing, granted an exception to Rule 15 in the case of Well 8. It was emphasized at the hearing that the old concept of commingling did not apply to wells equipped with the multiple-completion choke assembly, and that there was no basic difference between this and conventional methods inasmuch as commingling occurred *after* regulation, as it does in any tank battery where surface commingling takes place.

There are really no statutory obstacles to Railroad Commission acceptance of this producing method. Opinion No. 0-2245 concerning "The right of an operator to utilize gas produced from an upper horizon in lifting the oil produced from an oil sand at a lower horizon, without first producing the gas at the surface", was approved on May 20, 1940, by Texas Attorney General Mann and by his Opinion Committee. They ruled as follows: "So long as the proper steps are

TABLE 11—TUBULAR-GOODS COST OF SINGLE-STRING VS TWIN-STRING AND TUBINGLESS COMPLETION

	Twin String			Tubingless			Single String		
	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost
Surface	500	9⅝	$ 1,750	500	9⅝	$1,750	500	9⅝	$ 1,750
Oil String	4,600	7	9,450	9,000	2⅞	7,450	4,600	5½	6,750
Tubing	9,000	2⅜	5,600	None	—	—	4,500	2⅜	2,800
Total			$16,800			$9,200			$11,30G

taken to insure against the escape of oil or gas from one stratum into another, we do not believe that the statutes prevent the Commission from permitting the more efficient method of introducing the gas into the tubing below the surface, instead of requiring that the gas first be brought to the surface through a separate string of casing and then reintroduced into the well".

Other Applications

Use of the multiple-completion choke assembly is not limited to the applications that have been described. For example, the device is ideally suited to dual gas wells, and is being used in such wells in Mexico. Other, more specialized, installations are illustrated in Figs. 5 through 10. The single-string dual tubingless completion shown in Fig. 10 must surely represent the final stage in the reduction of initial equipment costs for dual completions.

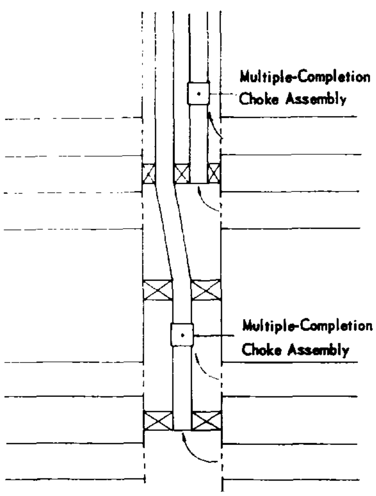

Fig. 5—Two-string quadruple completion.

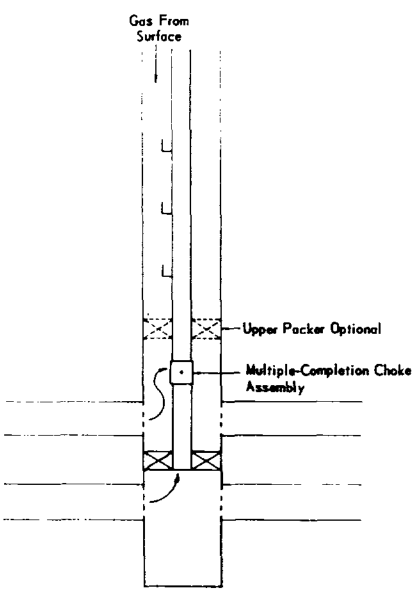

Fig. 6—Gas-lifting two zones with one string of flow valves.

Operational Suggestions

Following are some suggestions to those who contemplate using the multiple-completion choke assembly.

1. Set tubing with as little compression as possible to facilitate wireline operations.

2. Install the side-door choke in the landing nipple when the tubing is run to permit washing the well around the bottom of the tubing.

3. Pull the side-door choke and clean both zones before running the check-valve assembly, unless the differential in bottom-hole pressures is too great.

4. Use a wireline operator experienced in the operation of the multiple-completion choke assembly. Be sure he has good equipment on the job, including a sensitive weight indicator.

5. If the lower zone is protected by a check valve, do not run the orifice head with a blank in the opening communicating with the lower zone. This is similar to forcing a piston into a closed cylinder containing liquid, and will cause destruction of the O-ring seals on the tube and possible bending of the tube. This situation arises only when the lower zone is the weak zone and requires a check valve. Under these circumstances, when a test is made of the upper zone alone, the O-rings should be left off the tube of the orifice-head assembly. The higher pressure of the upper zone acting against the check valve of the lower zone will prevent flow from the lower zone.

6. Take extra precautions to assure accurate measurement of the fluids produced during tests. This is very important and should be stressed with field personnel.

7. For especially severe service, the metal sleeve-type check valve with an O-ring seal is recommended.

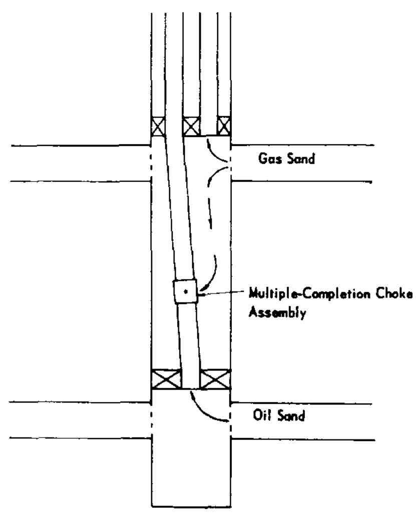

Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

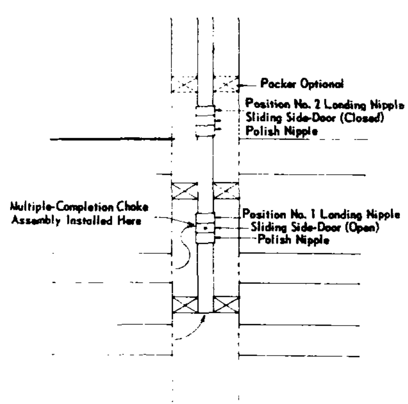

Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

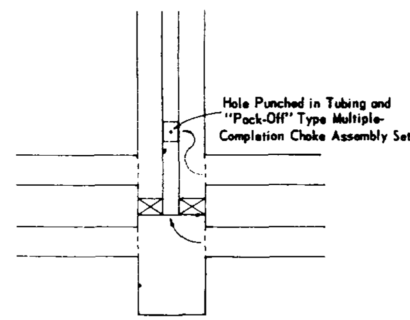

Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

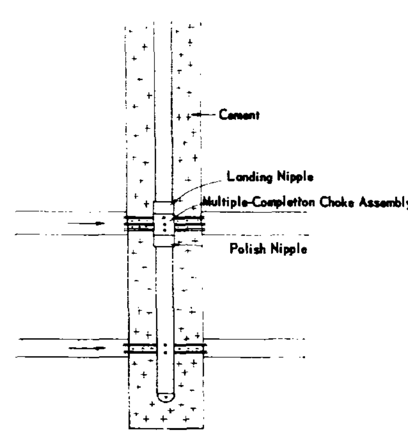

Fig. 10—One-string dual tubingless completion.

Future Development

The future development of the multiple-completion choke assembly and the method of simultaneous production through a single flow string is projected along the following two lines.

1. Surface-recorded bottom-hole pressures will be used to facilitate allocation and packer-leakage tests. A large portion of the wireline work could be eliminated if one had knowledge of the two pressures upstream from the choke and the tubing inlet pressure.

2. Informative material will be presented to state regulatory agencies in an effort to secure general acceptance of the process. This is largely a matter of demonstrating the feasibility of the method, both legally and mechanically, and showing that it will effect conservation and prevent waste.

Conclusions

Simultaneous production of two reservoirs through a single flow string can result in a significant reduction in completion and lifting costs, and will increase current income and ultimate recovery. The multiple-completion choke assembly can be used to maintain separation of the reservoirs and to control the rate of production from each. Test procedures have been developed which provide an acceptable method of determining the contribution from each zone. All requirements imposed by the various regulatory agencies can be satisfied.

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New Tool Permits Simultaneous Production of Two Reservoirs Through the Same Flow String

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Abstract

The constant search for methods to increase the efficiency of production systems and to reduce operating costs has led to the development of a wireline tool which makes it possible to produce and control two separate reservoirs through a single string of tubing. This paper is a progress report of the experience one company has gained with this tool in eight of its dually completed wells in Louisiana and Texas. Field tests have clearly demonstrated that this device can be used to maintain separation of production from two reservoirs, to control and determine the rate of production from each, and to change the rate of production as required. The advantages in simultaneous one-string multiple completions are enumerated, and various applications of the method are discussed.

Introduction

It is now almost standard operating procedure to complete wells in more than one zone wherever possible, with the great majority of these multiples being dual completions. This is a sign of the times. Saving must be accomplished wherever possible; however, there is no need to expand on this theme. All are painfully aware of the economic conditions within the industry. It is sufficient to say that the practice of multiple completions is here to stay and is becoming more popular every day. The only question is whether or not the practice has evolved into its most acceptable form.

The earlier duals were the concentric type, with one zone producing through the tubing and the other through the tubing-casing annulus. This method is still practiced to a large degree. It is popular because it is relatively inexpensive. Unfortunately, it has some rather severe limitations, with which the reader undoubtedly is familiar.

The twin-string dual is an improvement over the concentric in the sense that many of the problems associated with the concentric have been solved. The objectionable features of the twin-string dual are the high cost of equipping the well with an extra string of tubing, plus accessories, and the complications brought on by cramming all this tubing into one string of casing.

Still another type of multiple is the tubingless completion, wherein two or more small casing strings are cemented in place and subsequent operations performed with miniaturized equipment.

The purpose of this paper is to present a different concept in multiple completion—the simultaneous production of separate reservoirs in a single flow string. This method combines the simplicity and low cost of the concentric with the flexibility of the twin-string dual. In addition, it provides the unique advantage of prolonging natural flow from a low-pressure zone by combining its production with the fluids produced from a higher-pressure zone. The wireline tool which makes this method possible is the multiple-completion choke assembly.

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Construction and Operation of the Multiple-Completion Choke Assembly

Fig. 1 shows a well properly equipped to receive a multiple-completion choke assembly. A conventional packer separates the two producing zones. The upper packer is optional. A side-door choke landing-nipple hookup is located in the tubing

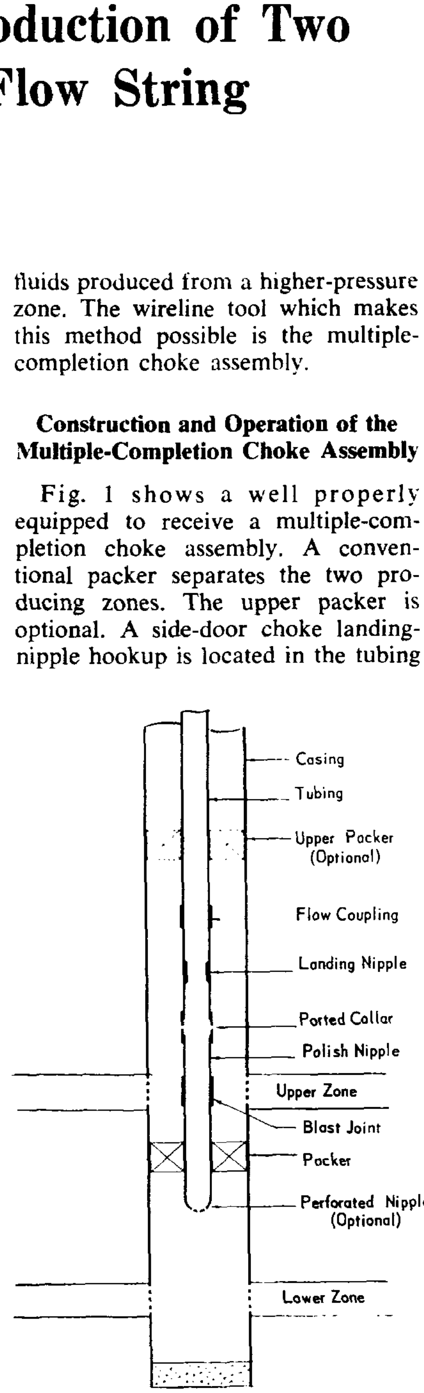

Fig. 1—Well properly equipped for multiple-completion choke assembly.

string above the lower packer. The multiple-completion choke assembly will be locked in this landing nipple. Normally located a joint or two above the upper zone, the position of the landing-nipple hookup can be varied to suit well conditions. For example, where the two zones are widely separated, it might be placed just above the lower packer to facilitate bottom-hole pressure tests of the lower zone.

The tool consists of two separate assemblies. The outer assembly, which is run independently and locked in the landing nipple, contains the check valves and packing seals which prevent flow from one zone to the other. In practice, however, only one check valve is usually required and is installed to protect the zone with the lower pressure.

The orifice-head assembly, which carries the tungsten-carbide choke beans, is run separately and is seated and locked in the outer assembly. The method of running each section is illustrated in Fig. 2.

Fig. 3 is a schematic drawing which shows more clearly how the device works. Production from the lower zone enters the assembly through a slotted section, flows around a resilient sleeve-type check valve, enters, and flows through the tube of the orifice-head assembly; it is choked and—now regulated—flows into the tubing. Produced fluids from the upper zone enter the casing opposite a blast joint on the tubing, flow through the ported collar of the side-door choke landing-nipple hookup, through the upper slotted secion, around the upper check valve, into the annulus surrounding the tube and through the upper-zone choke bean into the tubing. Here the two controlled flow streams, which have been kept separate up to this point, combine and flow to the surface.

Tubing Inlet Pressure

The pressure in the tubing at the junction of the two streams will be the minimum pressure required to lift the combined fluids to the surface (at zero surface pressure) and will be determined essentially by the gas-liquid ratio, production rate and tubing size. This pressure, which will hereafter be referred to as the "tubing inlet pressure", is of particular interest because of its importance in the application of the multiple-completion choke assembly. For example, suppose that investigation is being made into the possibility of using the assembly in a two-zone oil well with characteristics as tabulated in Table 1.

The combined production rate is 160 B/D of liquid (including salt water) and 87 Mcf/D of gas. The combined gas-liquid ratio is 543 cu ft/bbl. With a multiple-completion choke assembly set at 6,500 ft in 2⅜-in. OD tubing, it can be determined from published depth-pressure gradient curves[1] that the tubing inlet pressure will be approximately 850 psi.

The upper zone, with a productivity index of 0.5, will produce 96 B/D of liquid with a flowing bottom-hole pressure of approximately 1,308 psi. Since the flowing bottom-hole pressure of the weaker zone is greater than the tubing inlet pressure at the desired rate of production, this well can be produced by natural flow with a multiple-completion choke assembly. Natural flow will be maintained so long as the flowing bottom-hole pressure of the weaker zone (in this example, the upper zone) exceeds the tubing inlet pressure. At some point in the life of the upper zone, however, conditions favorable for natural flow *as a single completion* would no longer prevail. In other words, if it were being produced independently, some form of artificial lift would be required. The requirement is postponed because of the availability of the gas from the lower zone. When the lower zone can no longer "carry" the upper, a single set of flow valves can be run to produce both zones through the multiple-completion choke assembly.

TABLE 1—WELL DATA USED IN EVALUATING APPLICATION OF MULTIPLE-COMPLETION TOOL

	Upper Zone	Lower Zone
Producing Depths (ft)	6,600	7,200
Static BHP (psi)	1,500	3,400
Productivity Index (B/D/psi drop)	0.5	1.0
Oil Produced (B/D)	56	64
Salt Water Produced (B/D)	40	None
Gas Produced (Mcf/D)	39	48
Gas-Liquid Ratio	406	750

Allocation of Production

Allocation of fluids produced from each zone is based on a separate, individual zone test. To obtain such a test, the orifice-head assembly is removed from the check-valve assembly and brought to the surface with conventional wireline tools. (Removal of

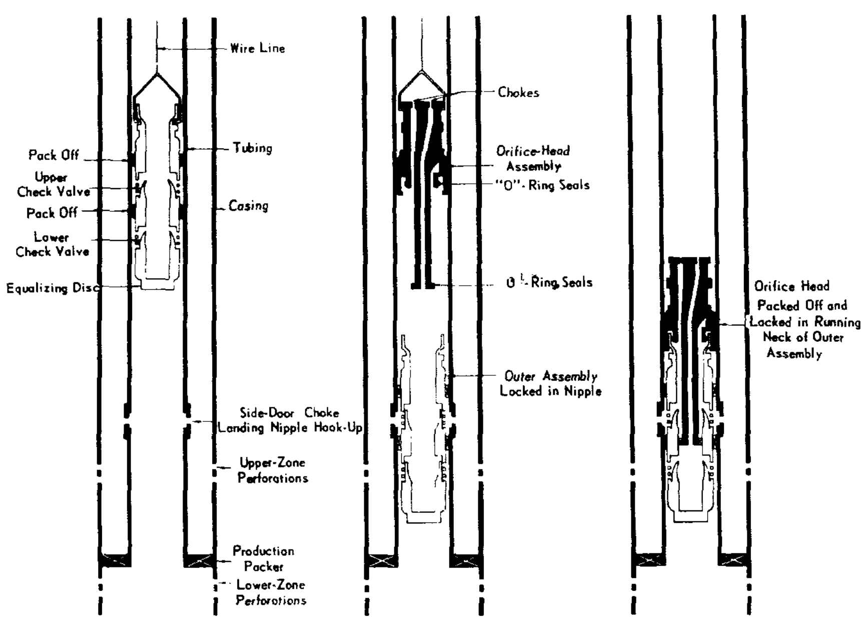

Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

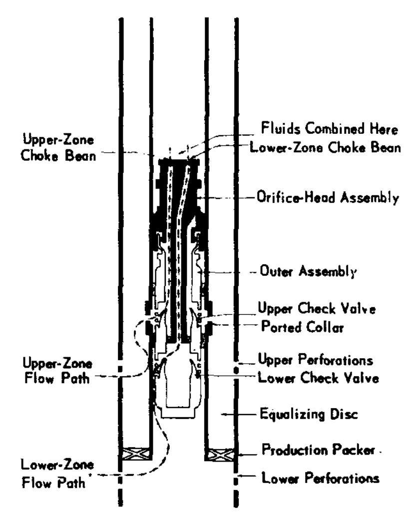

Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

the orifice head does not result in interzone flow, as the check-valve assembly remains in the well.) If the lower zone is to be tested, a blank bean is inserted in the opening in the orifice head communicating with the flow path of the upper zone. A choke bean, properly sized[1] to produce the desired volume of fluid from the lower zone, is placed in the opposite side of the orifice head. The orifice head is then lowered into the well, and landed and locked in the check-valve assembly. The upper zone cannot flow because of the blank choke bean. Produced fluids from the lower zone are measured into conventional surface facilities until a stabilized 24-hour test is obtained. The orifice head is again removed from the well. The blank bean is replaced with a production bean, and the assembly is returned to its operating position in the well. A stabilized test of the combined fluids produced is obtained. The predetermined rate from the lower zone is subtracted from the combined total, with the difference assigned to the upper zone.

The test procedure used will be determined by the flow conditions present in the well—specifically, whether or not one of the zones is in critical flow. A stream is said to be in critical flow when alterations in pressure downstream from an orifice do not affect the rate of flow through the orifice. The critical point occurs when the downstream pressure is 53 per cent of the upstream pressure. The significance of this phenomenon in the operation of the multiple-completion choke assembly is that, if one of the zones is in critical flow and the other is not, the zone not in critical flow can be regulated with a surface control without affecting the rate from the other. In the well described earlier, for example, if the tubing inlet pressure is not allowed to exceed approximately 1,765 psi (53 per cent of 3,336 psi), the rate from the lower zone will not be affected. In other words, back-pressure at the surface can be increased to the point of actually shutting-in the upper zone, with no effect on the rate from the lower zone.

In any well where two reservoirs are being produced simultaneously through the multiple-completion choke assembly, one of the following three conditions will exist: (1) one zone will be in critical flow; (2) neither zone will be in critical flow; or (3) both zones will be in critical flow. The method of testing for allocation will depend upon which one of these conditions exists.

The exact value of the critical P_2/P_1 ratio, whether it be 53 per cent or some other value, is of no particular concern. The ratio is not used quantitatively. As a matter of interest, however, in the wells where this critical point has been observed, the value has appeared reasonably close to 53 per cent.

The exact point of critical flow can be determined by changing the surface tubing pressure with an adjustable choke, measuring the rate of flow into conventional test facilities and observing the effect of the back-pressure changes.

At the same time, the tubing inlet pressure is measured with a bottom-hole pressure gauge. For example, tests run on a certain zone in a dual completion might result in the data shown in Table 2.

These data show the stream is going into critical flow between a tubing inlet pressure of 1,050 and 825 psi. This point can be determined more precisely if the results are shown graphically, as will be illustrated later in actual well tests.

A predetermined rate for this particular zone on a specific choke size for this range of tubing inlet pressures has now been established. It makes no difference what effect, if any, the second zone may have on the tubing inlet pressure in the well. Because this pressure can be determined, the rate from the first zone will be known. The difference is then assigned to the zone not tested individually, usually the lower-pressure zone.

If each zone can produce its allowable independently of the other, there may be some reason to test each separately. This procedure, of course, will require additional wireline work and is not essential in determining the production from each zone. The method has been used occasionally to demonstrate the consistency of flow-rate control possible with the choke beans in the tool.

Summarizing, production tests will follow one of two patterns. If either or both of the two zones is in critical flow when combined, a 24-hour stabilized test of the zone with the higher pressure is obtained. Back-pressure is not adjusted during this test. Following this, both zones are combined and tested for 24 hours at a stabilized rate. The difference in production is known to have come from the zone not tested singly.

If neither of the zones is in critical flow, the zone with the higher pressure is tested individually. The surface pressure is varied and the stabilized rates of production at the various back-pressures are measured. Tubing inlet pressure is recorded with a bottom-hole pressure gauge. This test predetermines the rate to be expected from this zone during periods of combined flow. The rate from the other zone will be determined by difference.

TABLE 2—CRITICAL FLOW DATA

Surface Tubing Pressure (psi)	Tubing Inlet Pressure (psi)	Liquid Rate (B/D)
700	1,300	50
500	1,050	55
300	825	60
100	600	60

Use Of The Tool In Gas Lifting

The multiple-completion choke assembly, when used as a gas-lift device, is in effect a single-point injection, retrievable flow valve utilizing gas supplied directly from the formation at maximum efficiency. An expert in gas-lift technology, in discussing conventional gas-lift systems,[2] has made the following pertinent observations.

> Which flow process, continuous or intermittent, will yield the greatest amount of produced stock-tank liquid for the least amount of injected gas at the available pressures? The continuous-flow process, if properly instituted, should be inherently more efficient than that of intermittent flow. The gas is put to work as needed and the high dissipation of initial energy in overcoming starting inertia is largely absent. Also, the external work done by the gas is negligible. The fact is, however, that maximum efficiency in the continuous-flow process can only be realized by putting the gas to work as soon as possible. This means high injection pressures at moderate depths. Because the high injection pressures necessary for maximum efficiency are seldom available, it has been found in practice that the intermittent-flow process is frequently more efficient than that of continuous flow, for wells that produce moderate amounts of liquid.
>
> It is significant to point out here that the Phillips paper, previously referred to, lists data from some 34 flowing wells and 16 gas-lift wells (continuous flow). The thermodynamic flow efficiency for the flowing wells was on the order of 85 to 95 per cent, whereas the gas-lift wells were mainly of the order of 40-60 per cent. There is no reason why continuous-flow gas-lift wells should not closely approximate the efficiency of naturally flowing wells, if the installations are correctly designed.
>
> It is recognized that the high-pressure requirements for maximum efficient operations is definitely a limiting factor in any practical well installation. It is most important to recognize that, as injection pressures are decreased below the optimum, the flow efficiency

[1]References given at end of paper.

of the installation falls off very rapidly.

Low injection pressures mean high injection GORs and should be avoided where possible.

. . . and to emphasize the advantage of valve installations in which the valves may be retrieved and reset or replaced.

These statements make a strong case for using the multiple-completion choke assembly as a gas-lift mechanism. The high injection pressures necessary for maximum efficiency are now within practical reach. Almost any well can be produced by continuous lift. The "flow valve" can be removed and replaced by wireline. All this adds up to maximum efficiency at minimum cost.

To illustrate the truly significant potential of the multiple-completion choke assembly as it applies to gas lift, a comparison was made between gas lifting with a conventional system and with the multiple-completion choke assembly in a well in the Sour Lake field, Hardin County, Tex. The Railroad Commission of Texas has granted permission to use in this well a gas sand at 9,610 ft to supply gas-lift gas through the multiple-completion choke assembly to lift produced fluids from an oil sand at 9,800 ft. The results of this study[3] were rather startling. The input gas required using the conventional system was calculated to be 560 Mcf/D as compared to only 34 Mcf/D using the multiple-completion choke assembly; in addition, it should be remembered that the latter method does not require surface gas-lift facilities such as high-pressure separators or compressors, heaters, dehydration equipment, delivery lines, etc.

Data pertinent to the analysis and the results thereof are presented in Table 3.

Field Tests

Sun Oil Co.'s first test of the multiple-completion choke assembly was in the Kinder field, Allen Parish, La., in Sept., 1959.

Additional development and testing were done in the North Winnie field in a surface manifold with a high-pressure oil well flowing through the tool. Sand-laden liquid was pumped into the flow stream where it entered the manifold. The severity of these and other surface and subsurface tests has resulted in the development of a very durable and rugged tool.

Well No. 1

The first successful field test was begun March 31, 1960, in a well in the Kinder field. The Louisiana Conservation Commission approved a six-month test period and, after a three-month interval, granted permanent approval to use the tool in this well, which will be identified as Well No. 1.

Sun now has eight wells equipped with multiple-completion choke assemblies, and several more installations either are planned or are in progress. A description of the wells now equipped with the assembly appears in Table 4.

Well 1, prior to installation of the multiple-completion choke assembly, was a concentric-type dual completion with the upper zone flowing in the annulus between 2⅜-in. tubing and 5½-in. casing and the lower zone flowing through the 2⅜-in. tubing. As a result of using the tool, the combined hydrocarbon production from the two zones was increased by approximately 20 B/D and 300 Mcf/D, representing an annual increase in gross income of $48,400.

Tables 5 and 6 illustrate the exact method used to allocate production from the two zones in Well 1. Table 5 represents four consecutive 24-hour tests of stabilized flow from the upper zone with the lower zone closed in by a blank choke bean in the orifice head. It is not necessary, as a routine matter, to run the tests this long. The tool was experimental during this period, and the stabilized nature of the flow possible with the device was being demonstrated. Table 6 represents tests made of the combined flow, with the resulting allocation to each zone.

Table 7 shows the results obtained during the following months when testing the upper zone individually, and demonstrates the accurate flow-rate control possible with the choke beans used in the assembly. The same 5/64-in. choke was used throughout the period shown. Gas production was measured by orifice meter and liquid production was gauged in a 210-bbl tank.

TABLE 3—GAS-LIFTING WITH MULTIPLE-COMPLETION TOOL COMPARED TO CONVENTIONAL METHOD

Conditions	
Required Production (B/D)	100 oil, 100 SW
Productivity Index (B/D/psi drop)	0.154
Surface Pressure (psi)	100
Static BHP Lower Zone (psi)	3,800
Static BHP Upper Zone (psi)	4,000
Gas-Oil Ratio Lower Zone (cu ft/bbl)	500
Gas-Liquid Ratio Lower Zone (cu ft/bbl)	250
Required Gas-Liquid Ratio for Well to Flow (cu ft/bbl)	420
Input Gas Pressure (psi)	700

Comparison Between the Two Methods

	Conventional	Proposed
Number of Flow Valves	11	1
Depth of Lift (ft)	4,500	9,500
Input Gas-Liquid Ratio (cu ft/bbl)	2,800	170 (420-250)
Gas Required (Mcf/D)	560	34

TABLE 4—DESCRIPTION OF WELLS USING MULTIPLE COMPLETION TOOL

Well No.	Location	Depth (ft)	Static BHP (psi)	Production (B/D)	Gas-Liquid Ratio (cu ft/bbl)
1	Kinder, La.	8,067	2,575	6 Oil	22,100
		8,448	2,460	19 Cond.	18,466
2	Bayou Sale, La.	14,025	5,870	20 Oil	1,000
		14,236	6,533	75 Oil, 75 SW	7,750
3	Kinder, La.	7,678	3,263	64 Oil	784
		8,379	3,371	37 Cond.	19,100
4	Belle Isle, La.	13,958	6,500	129 Oil	735
		13,983	6,500	129 Oil	945
5	Kinder, La.	7,394	3,290	7 Oil, 15 SW	643
		8,390	3,485	64 Cond.	16,188
6	Belle Isle, La.	12,840	5,670	115 Oil	906
		13,398	5,781	129 Oil	423
7	Bateman Lake, La.	10,154	4,538	71 Oil	2,929
		11,700	5,060	65 Oil, 10 SW	3,354
8	Sour Lake, Tex.	4,710	814	No Cond., No SW	113 Mcf Dry Gas
		4,788	1,093	14 Oil	649

TABLE 5—INDIVIDUAL TEST DATA FOR UPPER ZONE, WELL NO. 1—LOWER ZONE BLANKED-OFF

		Production		
Date	Surface Tubing Pressure (psig)	Oil (B/D)	Gas (Mcf/D)	Gas-Oil Ratio (cu ft/bbl)
6-9-60	900	10.39	242	23,300
6-10-60	900	10.68	237	22,100
6-11-60	900	10.98	238	21,700
6-12-60	900	10.97	238	21,700
	Average	10.75	239	22,100

TABLE 6—COMBINED PRODUCTION DATA AND ALLOCATION TO EACH ZONE, WELL NO. 1

		Measured Production		Calculated Production			
				Upper Zone		Lower Zone	
Date	Surface Tubing Pressure (psig)	Total Liquid (B/D)	Total Gas (Mcf/D)	Oil (B/D)	Gas (Mcf/D)	Condensate (B/D)	Gas (Mcf/D)
6-16-60	900	28.92	498	10.75*	239*	18.17	259
6-17-60	900	30.07	463	10.75	239	19.32	224
6-18-60	900	23.69	442	10.75	239	12.94	203
6-19-60	900	26.87	452	10.75	239	16.12	213
6-20-60	900	27.45	466	10.75	239	16.70	227

*Based on predetermined tests shown in Table 5.

Well No. 2

Well 2 was completed in May, 1961. The upper zone on drill-stem test was judged to be noncommercial but did produce some oil. This is a situation frequently confronting an operator. A zone looks doubtful on an electric log and a drill-stem test is not conclusive—should he make a single or dual completion? It is a perplexing question. The great expense involved in twin-string duals will not often justify a thorough evaluation of these doubtful zones. On the other hand, he may be passing up a commercial reserve. The multiple-completion choke assembly can be used to good advantage in this situation. Doubtful producing horizons can be fully evaluated at low additional cost and, when combined with good producers, can be depleted without artificial lift. This will result in the recovery of more oil and more gas.

Well 2 is a deep, directionally drilled, high-pressure, high-temperature well—a water location—and provided quite a test for the tool. The wireline operations in this well, however, have gone quite smoothly.

Well No. 3

Well 3 was originally a single-completion oil well. In June, 1961, the oil zone was dualled with a deeper sand productive of gas and condensate.

Table 8 gives the results of single-zone tests of the lower zone; Fig. 4 is a graphic representation of these data. Note that the well goes into critical flow at a tubing inlet pressure of 1,835 psi, or 55 per cent of the upstream pressure of approximately 3,300 psi.

After the tests of the lower zone were concluded, the upper zone was tested and then the two zones were combined. The tubing inlet pressure at 7,550 ft was measured with a bottom-hole pressure gauge and found to be 1,720 psi with a surface tubing pressure of 1,100 psi. As a check, the depth-pressure gradient curves were used to determine the tubing inlet pressure under these conditions of flow. This value was interpolated to be 1,650 psi. The lower zone is in critical flow under these conditions. This means that the predetermined rate of production of the lower zone is not affected by combining with the upper.

Well No. 4

Well 4, a water location, was completed in June, 1961. The upper zone is only 8-ft thick and would not justify the additional cost of a twin-string dual.

Production tests of the lower zone with a 4.5/64-in. choke bean in the orifice head were made as shown in Table 9.

These tests show that the well goes out of critical flow when the surface pressure is increased manually above 250 psi. Plotting oil rate vs tubing pressure locates the critical point at 875 psi.

Following these tests, the orifice head was pulled and run back with the lower zone blanked and a 4.5/64-in. choke bean controlling production from the upper zone. On stabilized test in critical flow, the upper zone produced 152 BOPD (neither zone produces salt water) with a gas-oil ratio of 720 cu ft/bbl.

The orifice head was then pulled and returned with each zone open to a 4.5/64-in. choke bean. Combined production was gauged at 311 BOPD, a good check with the individual zone tests (157 and 152, a total of 309 BOPD).

TABLE 9—WELL DATA, LOWER ZONE, WELL NO. 4

Oil Production (B/D)	Gas-Oil Ratio (cu ft/bbl)	Surface Tubing Pressure (psi)
156	827	150
158	919	150
157	936	250
149	905	975
138	972	1,075
122	957	1,200
100	900	1,450

Well No. 5 Through 7

Well 5 was a singly-completed, deficient oil well when it was dually-completed in Aug., 1961, with a gas zone. The oil zone was not good enough to support a twin-string completion and would have been abandoned had not the multiple-completion choke assembly been available.

Well 6, a water location, was completed in Aug., 1961, and has been produced without incident.

Well 7, another water location, was completed in Aug., 1961. Tests show that both zones are in critical flow. Each zone was tested separately. The lower zone made 65 BOPD, and the upper zone was tested at 71 BOPD. When combined, the two zones produced 132 BOPD.

Well No. 8

Well 8, the first test in Texas, was worked-over and completed as a dual in Oct., 1961. This well is completed in a low-pressure gas sand and a low-pressure oil sand. The gas is used to lower the gradient in the well to allow flow from the oil zone. The low bottom-hole pressure existing in the gas

TABLE 7—INDIVIDUAL TEST DATA FOR UPPER ZONE, WELL NO. 1—LOWER ZONE BLANKED-OFF

Date	Choke Size (in.)	Production Oil (B/D)	Production Gas (Mcf/D)
7-24-60	5/64	7.23	248
10-5-60	6/64	7.80	227
10-18-60	5/64	7.80	227
12-4-60	5/64	7.23	209
1-27-61	3.5/64	6.38	175
5-29-61	3.5/64	6.96	150

TABLE 8—INDIVIDUAL TEST DATA OF LOWER ZONE, WELL NO. 3—UPPER ZONE BLANKED-OFF

Tubing Pressure (psig)		Production	
Surface	Inlet	Condensate (B/D)	Gas (Mcf/D)
790	1,466	38.40	726,802
950	1,549	39.41	726,802
1,060	1,835	37.34	708,654
1,250	2,091	32.12	638,787
1,335	2,345	30.06	555,196
1,475	2,517	22.82	454,251
1,600	3,125	12.44	222,078

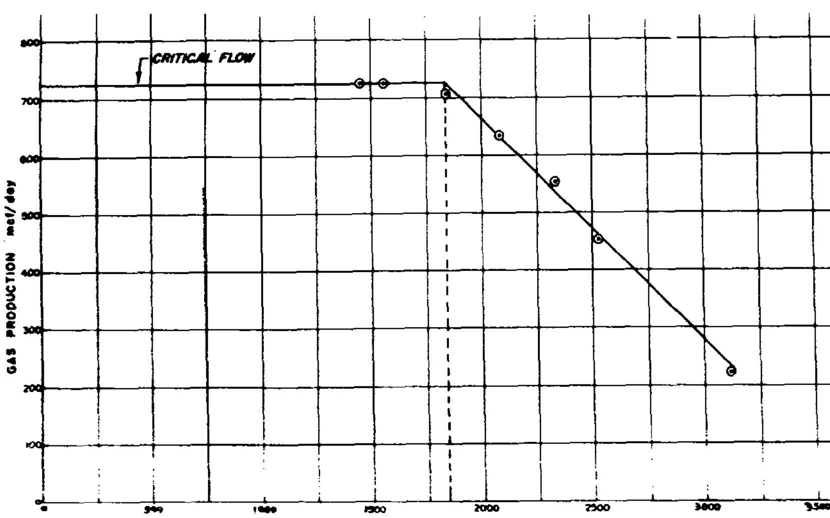

Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

sand will not justify the surface facilities that would be required for the sale of the gas, nor will the low pressure justify the use of this gas in a conventional gas-lift system.

A new check valve received its first subsurface test in Well 8. Results were quite encouraging, and the valve subsequently has been used in other wells. The lower zone in Well 8 was acidized with the new check valve protecting the upper zone. The treatment was successful mechanically, and the check valve functioned perfectly. Maximum differential pressure across the check valve during acidizing was 4,000 psi.

This new check valve is a sleeve-type steel valve incorporating both a metal-to-metal and an O-ring seal. In time, it may replace entirely the resilient-type check valve.

The required packer-leakage test in Well 8 was obtained by blanking-off the upper zone in the orifice head and flowing the upper zone through the casing. The lower zone was open to the tubing. The casing and tubing pressures were recorded simultaneously. This is the method for obtaining a packer-leakage test when there is no packer set above the upper zone. If the upper packer is set, packer-leakage tests can be made by measuring the bottom-hole pressure of one zone while flowing the other. A device is now available which will allow a bottom-hole pressure element to be run with the orifice-head assembly. The shut-in bottom-hole pressure of one zone is measured while the other is open to flow. This type of packer-leakage test should be more realistic than the conventional test where surface pressure fluctuations are observed.

Allocation tests in Well 8 are made by blanking-off the lower zone and measuring the gas produced from the upper zone through the tubing. The two zones are then combined and the increase in gas rate is calculated from the orifice-meter chart. This increase represents the volume of gas produced from the lower zone. All liquids produced are known to have come from the lower zone, as the upper zone produces dry gas. The tubing inlet pressure is measured. The results show that the upper zone is in critical flow. This means that production from the lower zone has no effect on the predetermined rate from the upper zone.

It can be argued that this method of gas measurement is considerably more accurate than the usual method of measuring gas into and out of a conventional, intermitting-type gas-lift well.

Economics

Use of the multiple-completion choke assembly to produce two reservoirs simultaneously through a single flow string results in an initial saving in equipment and rig costs, and in later workover costs, when compared with twin-string duals.

The savings possible cover a wide range. For example, the equipment costs of Well 6 are compared with those of a twin-string dual in the same field, on a comparative-footage basis, in Table 10. This represents a difference of $42,131 and includes neither the saving in rig time nor the considerable saving in workover costs which may result. Anyone who has worked-over a deep twin-string dual in a water location will attest—perhaps grimly—to the costs that can be incurred in such operations.

At the other end of the scale, in the relatively shallow wells, a cost comparison between tubular requirements in three different types of dual completions is shown in Table 11.

Initial completion operations conceivably might result in the tubingless-completion dual costing more than the single-string dual.

Simplicity and flexibility always should be taken into account when planning the system that will produce the most hydrocarbons for the least money.

The wireline expense associated with the simultaneous, one-flow-string method will depend primarily upon operator skill, accessibility of location, depth and testing requirements. This expense will be relatively high for the first month or two, and then will taper off. Wireline costs for the year 1961 in Well 1 have averaged $65 per month. In many wells, as in Well 1, the wireline expense will be more than compensated for by increased production, reduced lifting costs and greater ultimate recovery.

TABLE 10 — TUBULAR-GOODS COST OF TWIN-STRING VS SINGLE-STRING DUAL COMPLETION

	Well "X"	Well No. 6
Conductor	$ 788 (20 in.)	$ 538 (16 in.)
Surface	13,981 (11¾ in.)	11,200 (10¾ in.)
Oil String	61,500 (7⅝ in.)	39,600 (5½ in.)
Tubing	27,000 (2⅜ in.)	11,200 (2⅜ in.)
Wellhead Costs	5,200	3,800
Total	$108,469	$66,338

Acceptance By Regulatory Agencies

Permission to use the multiple-completion choke assembly in Well 1 was granted by the Louisiana Conservation Commission on a six-month basis, and then extended permanently for that particular well. Approval for the other two Kinder wells was obtained after a public hearing. The hearing was necessary because the lower producing sand was unitized and created a diversity of ownership in those wells.

Approval for the other Louisiana installations has been obtained after filing a routine request for permission to dually complete, with the provision that a review of the well be made after a six-month operational period.

In Texas, the Railroad Commission has been somewhat stymied by Statewide Rule 15, which says "No well shall be permitted to produce oil and/or gas from different strata through the same string of casing".

This rule was written some 27 years ago to prevent an operator from indiscriminately opening two or more zones in the same wellbore, and commingling this production without regulation or proper identification as to source.

The Railroad Commission, after a public hearing, granted an exception to Rule 15 in the case of Well 8. It was emphasized at the hearing that the old concept of commingling did not apply to wells equipped with the multiple-completion choke assembly, and that there was no basic difference between this and conventional methods inasmuch as commingling occurred *after* regulation, as it does in any tank battery where surface commingling takes place.

There are really no statutory obstacles to Railroad Commission acceptance of this producing method. Opinion No. 0-2245 concerning "The right of an operator to utilize gas produced from an upper horizon in lifting the oil produced from an oil sand at a lower horizon, without first producing the gas at the surface", was approved on May 20, 1940, by Texas Attorney General Mann and by his Opinion Committee. They ruled as follows: "So long as the proper steps are

TABLE 11—TUBULAR-GOODS COST OF SINGLE-STRING VS TWIN-STRING AND TUBINGLESS COMPLETION

	Twin String			Tubingless			Single String		
	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost
Surface	500	9⅝	$ 1,750	500	9⅝	$1,750	500	9⅝	$ 1,750
Oil String	4,600	7	9,450	9,000	2⅞	7,450	4,600	5½	6,750
Tubing	9,000	2⅜	5,600	None	—	—	4,500	2⅜	2,800
Total			$16,800			$9,200			$11,300

taken to insure against the escape of oil or gas from one stratum into another, we do not believe that the statutes prevent the Commission from permitting the more efficient method of introducing the gas into the tubing below the surface, instead of requiring that the gas first be brought to the surface through a separate string of casing and then reintroduced into the well".

Other Applications

Use of the multiple-completion choke assembly is not limited to the applications that have been described. For example, the device is ideally suited to dual gas wells, and is being used in such wells in Mexico. Other, more specialized, installations are illustrated in Figs. 5 through 10. The single-string dual tubingless completion shown in Fig. 10 must surely represent the final stage in the reduction of initial equipment costs for dual completions.

Operational Suggestions

Following are some suggestions to those who contemplate using the multiple-completion choke assembly.

1. Set tubing with as little compression as possible to facilitate wireline operations.

2. Install the side-door choke in the landing nipple when the tubing is run to permit washing the well around the bottom of the tubing.

3. Pull the side-door choke and clean both zones before running the check-valve assembly, unless the differential in bottom-hole pressures is too great.

4. Use a wireline operator experienced in the operation of the multiple-completion choke assembly. Be sure he has good equipment on the job, including a sensitive weight indicator.

5. If the lower zone is protected by a check valve, do not run the orifice head with a blank in the opening communicating with the lower zone. This is similar to forcing a piston into a closed cylinder containing liquid, and will cause destruction of the O-ring seals on the tube and possible bending of the tube. This situation arises only when the lower zone is the weak zone and requires a check valve. Under these circumstances, when a test is made of the upper zone alone, the O-rings should be left off the tube of the orifice-head assembly. The higher pressure of the upper zone acting against the check valve of the lower zone will prevent flow from the lower zone.

6. Take extra precautions to assure accurate measurement of the fluids produced during tests. This is very important and should be stressed with field personnel.

7. For especially severe service, the metal sleeve-type check valve with an O-ring seal is recommended.

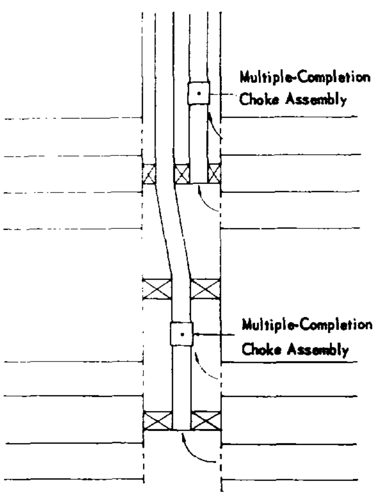

Fig. 5—Two-string quadruple completion.

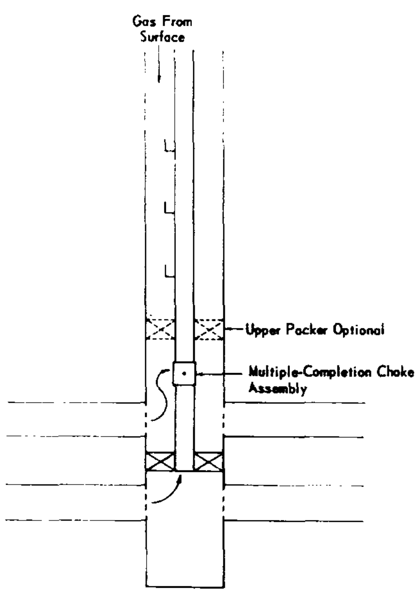

Fig. 6—Gas-lifting two zones with one string of flow valves.

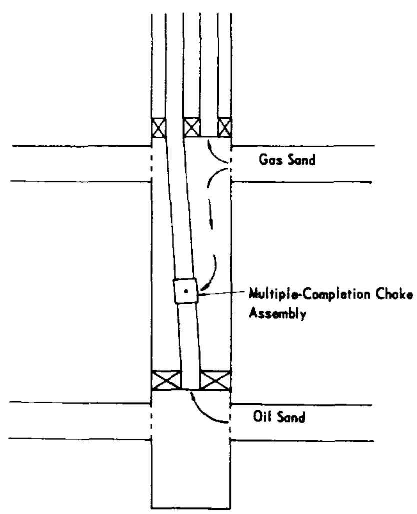

Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

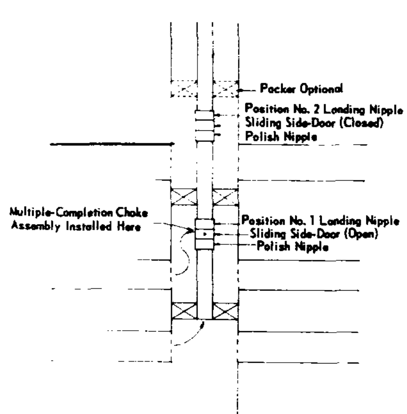

Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

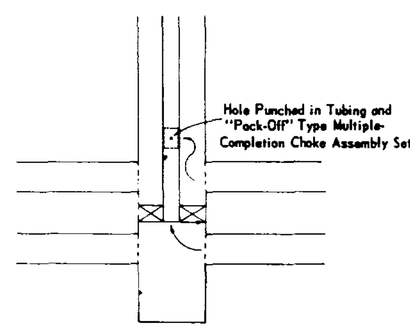

Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

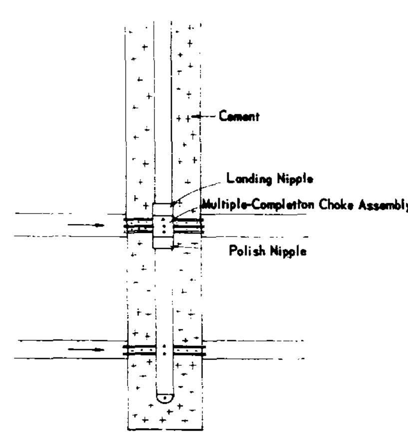

Fig. 10—One-string dual tubingless completion.

Future Development

The future development of the multiple-completion choke assembly and the method of simultaneous production through a single flow string is projected along the following two lines.

1. Surface-recorded bottom-hole pressures will be used to facilitate allocation and packer-leakage tests. A large portion of the wireline work could be eliminated if one had knowledge of the two pressures upstream from the choke and the tubing inlet pressure.

2. Informative material will be presented to state regulatory agencies in an effort to secure general acceptance of the process. This is largely a matter of demonstrating the feasibility of the method, both legally and mechanically, and showing that it will effect conservation and prevent waste.

Conclusions

Simultaneous production of two reservoirs through a single flow string can result in a significant reduction in completion and lifting costs, and will increase current income and ultimate recovery. The multiple-completion choke assembly can be used to maintain separation of the reservoirs and to control the rate of production from each. Test procedures have been developed which provide an acceptable method of determining the contribution from each zone. All requirements imposed by the various regulatory agencies can be satisfied.

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★★★

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New Tool Permits Simultaneous Production of Two Reservoirs Through the Same Flow String

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Abstract

The constant search for methods to increase the efficiency of production systems and to reduce operating costs has led to the development of a wireline tool which makes it possible to produce and control two separate reservoirs through a single string of tubing. This paper is a progress report of the experience one company has gained with this tool in eight of its dually completed wells in Louisiana and Texas. Field tests have clearly demonstrated that this device can be used to maintain separation of production from two reservoirs, to control and determine the rate of production from each, and to change the rate of production as required. The advantages in simultaneous one-string multiple completions are enumerated, and various applications of the method are discussed.

Introduction

It is now almost standard operating procedure to complete wells in more than one zone wherever possible, with the great majority of these multiples being dual completions. This is a sign of the times. Saving must be accomplished wherever possible; however, there is no need to expand on this theme. All are painfully aware of the economic conditions within the industry. It is sufficient to say that the practice of multiple completions is here to stay and is becoming more popular every day. The only question is whether or not the practice has evolved into its most acceptable form.

The earlier duals were the concentric type, with one zone producing through the tubing and the other through the tubing-casing annulus. This method is still practiced to a large degree. It is popular because it is relatively inexpensive. Unfortunately, it has some rather severe limitations, with which the reader undoubtedly is familiar.

The twin-string dual is an improvement over the concentric in the sense that many of the problems associated with the concentric have been solved. The objectionable features of the twin-string dual are the high cost of equipping the well with an extra string of tubing, plus accessories, and the complications brought on by cramming all this tubing into one string of casing.

Still another type of multiple is the tubingless completion, wherein two or more small casing strings are cemented in place and subsequent operations performed with miniaturized equipment.

The purpose of this paper is to present a different concept in multiple completion—the simultaneous production of separate reservoirs in a single flow string. This method combines the simplicity and low cost of the concentric with the flexibility of the twin-string dual. In addition, it provides the unique advantage of prolonging natural flow from a low-pressure zone by combining its production with the fluids produced from a higher-pressure zone. The wireline tool which makes this method possible is the multiple-completion choke assembly.

Construction and Operation of the Multiple-Completion Choke Assembly

Fig. 1 shows a well properly equipped to receive a multiple-completion choke assembly. A conventional packer separates the two producing zones. The upper packer is optional. A side-door choke landing-nipple hookup is located in the tubing

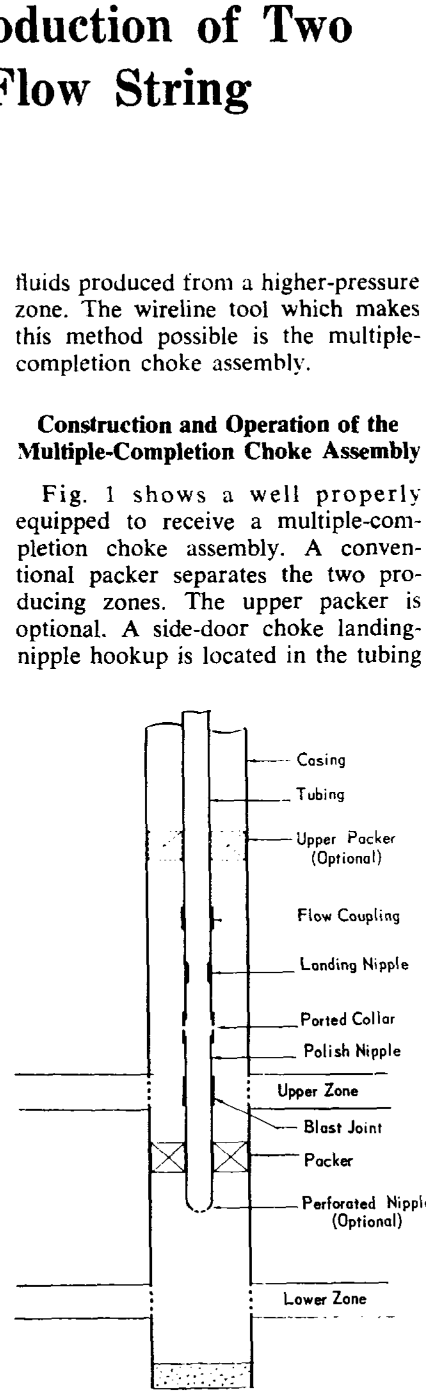

Fig. 1—Well properly equipped for multiple-completion choke assembly.

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string above the lower packer. The multiple-completion choke assembly will be locked in this landing nipple. Normally located a joint or two above the upper zone, the position of the landing-nipple hookup can be varied to suit well conditions. For example, where the two zones are widely separated, it might be placed just above the lower packer to facilitate bottom-hole pressure tests of the lower zone.

The tool consists of two separate assemblies. The outer assembly, which is run independently and locked in the landing nipple, contains the check valves and packing seals which prevent flow from one zone to the other. In practice, however, only one check valve is usually required and is installed to protect the zone with the lower pressure.

The orifice-head assembly, which carries the tungsten-carbide choke beans, is run separately and is seated and locked in the outer assembly. The method of running each section is illustrated in Fig. 2.

Fig. 3 is a schematic drawing which shows more clearly how the device works. Production from the lower zone enters the assembly through a slotted section, flows around a resilient sleeve-type check valve, enters, and flows through the tube of the orifice-head assembly; it is choked and—now regulated—flows into the tubing. Produced fluids from the upper zone enter the casing opposite a blast joint on the tubing, flow through the ported collar of the side-door choke landing-nipple hookup, through the upper slotted secion, around the upper check valve, into the annulus surrounding the tube and through the upper-zone choke bean into the tubing. Here the two controlled flow streams, which have been kept separate up to this point, combine and flow to the surface.

Tubing Inlet Pressure

The pressure in the tubing at the junction of the two streams will be the minimum pressure required to lift the combined fluids to the surface (at zero surface pressure) and will be determined essentially by the gas-liquid ratio, production rate and tubing size. This pressure, which will hereafter be referred to as the "tubing inlet pressure", is of particular interest because of its importance in the application of the multiple-completion choke assembly. For example, suppose that investigation is being made into the possibility of using the assembly in a two-zone oil well with characteristics as tabulated in Table 1.

The combined production rate is 160 B/D of liquid (including salt water) and 87 Mcf/D of gas. The combined gas-liquid ratio is 543 cu ft/bbl. With a multiple-completion choke assembly set at 6,500 ft in 2⅜-in. OD tubing, it can be determined from published depth-pressure gradient curves[1] that the tubing inlet pressure will be approximately 850 psi.

The upper zone, with a productivity index of 0.5, will produce 96 B/D of liquid with a flowing bottom-hole pressure of approximately 1,308 psi. Since the flowing bottom-hole pressure of the weaker zone is greater than the tubing inlet pressure at the desired rate of production, this well can be produced by natural flow with a multiple-completion choke assembly. Natural flow will be maintained so long as the flowing bottom-hole pressure of the weaker zone (in this example, the upper zone) exceeds the tubing inlet pressure. At some point in the life of the upper zone, however, conditions favorable for natural flow *as a single completion* would no longer prevail. In other words, if it were being produced independently, some form of artificial lift would be required. The requirement is postponed because of the availability of the gas from the lower zone. When the lower zone can no longer "carry" the upper, a single set of flow valves can be run to produce both zones through the multiple-completion choke assembly.

TABLE 1—WELL DATA USED IN EVALUATING APPLICATION OF MULTIPLE-COMPLETION TOOL

	Upper Zone	Lower Zone
Producing Depths (ft)	6,600	7,200
Static BHP (psi)	1,500	3,400
Productivity Index (B/D/psi drop)	0.5	1.0
Oil Produced (B/D)	56	64
Salt Water Produced (B/D)	40	None
Gas Produced (Mcf/D)	39	48
Gas-Liquid Ratio	406	750

Allocation of Production

Allocation of fluids produced from each zone is based on a separate, individual zone test. To obtain such a test, the orifice-head assembly is removed from the check-valve assembly and brought to the surface with conventional wireline tools. (Removal of

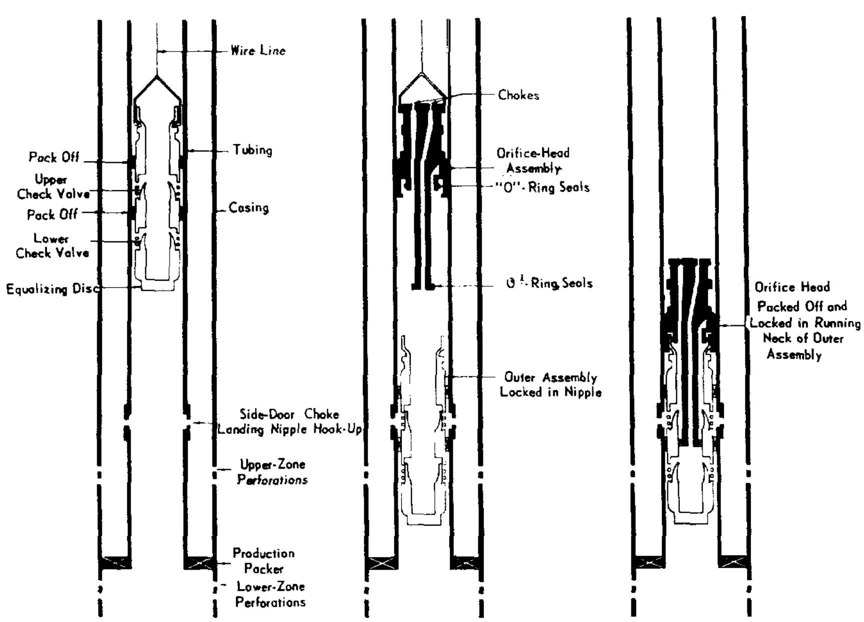

Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

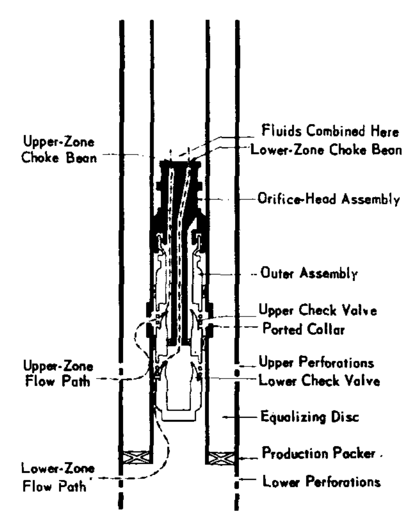

Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

the orifice head does not result in interzone flow, as the check-valve assembly remains in the well.) If the lower zone is to be tested, a blank bean is inserted in the opening in the orifice head communicating with the flow path of the upper zone. A choke bean, properly sized[1] to produce the desired volume of fluid from the lower zone, is placed in the opposite side of the orifice head. The orifice head is then lowered into the well, and landed and locked in the check-valve assembly. The upper zone cannot flow because of the blank choke bean. Produced fluids from the lower zone are measured into conventional surface facilities until a stabilized 24-hour test is obtained. The orifice head is again removed from the well. The blank bean is replaced with a production bean, and the assembly is returned to its operating position in the well. A stabilized test of the combined fluids produced is obtained. The predetermined rate from the lower zone is subtracted from the combined total, with the difference assigned to the upper zone.

The test procedure used will be determined by the flow conditions present in the well—specifically, whether or not one of the zones is in critical flow. A stream is said to be in critical flow when alterations in pressure downstream from an orifice do not affect the rate of flow through the orifice. The critical point occurs when the downstream pressure is 53 per cent of the upstream pressure. The significance of this phenomenon in the operation of the multiple-completion choke assembly is that, if one of the zones is in critical flow and the other is not, the zone not in critical flow can be regulated with a surface control without affecting the rate from the other. In the well described earlier, for example, if the tubing inlet pressure is not allowed to exceed approximately 1,765 psi (53 per cent of 3,336 psi), the rate from the lower zone will not be affected. In other words, back-pressure at the surface can be increased to the point of actually shutting-in the upper zone, with no effect on the rate from the lower zone.

In any well where two reservoirs are being produced simultaneously through the multiple-completion choke assembly, one of the following three conditions will exist: (1) one zone will be in critical flow; (2) neither zone will be in critical flow; or (3) both zones will be in critical flow. The method of testing for allocation will depend upon which one of these conditions exists.

The exact value of the critical P_2/P_1 ratio, whether it be 53 per cent or some other value, is of no particular concern. The ratio is not used quantitatively. As a matter of interest, however, in the wells where this critical point has been observed, the value has appeared reasonably close to 53 per cent.

The exact point of critical flow can be determined by changing the surface tubing pressure with an adjustable choke, measuring the rate of flow into conventional test facilities and observing the effect of the back-pressure changes.

At the same time, the tubing inlet pressure is measured with a bottom-hole pressure gauge. For example, tests run on a certain zone in a dual completion might result in the data shown in Table 2.

These data show the stream is going into critical flow between a tubing inlet pressure of 1,050 and 825 psi. This point can be determined more precisely if the results are shown graphically, as will be illustrated later in actual well tests.

A predetermined rate for this particular zone on a specific choke size for this range of tubing inlet pressures has now been established. It makes no difference what effect, if any, the second zone may have on the tubing inlet pressure in the well. Because this pressure can be determined, the rate from the first zone will be known. The difference is then assigned to the zone not tested individually, usually the lower-pressure zone.

If each zone can produce its allowable independently of the other, there may be some reason to test each separately. This procedure, of course, will require additional wireline work and is not essential in determining the production from each zone. The method has been used occasionally to demonstrate the consistency of flow-rate control possible with the choke beans in the tool.

Summarizing, production tests will follow one of two patterns. If either or both of the two zones is in critical flow when combined, a 24-hour stabilized test of the zone with the higher pressure is obtained. Back-pressure is not adjusted during this test. Following this, both zones are combined and tested for 24 hours at a stabilized rate. The difference in production is known to have come from the zone not tested singly.

If neither of the zones is in critical flow, the zone with the higher pressure is tested individually. The surface pressure is varied and the stabilized rates of production at the various back-pressures are measured. Tubing inlet pressure is recorded with a bottom-hole pressure gauge. This test predetermines the rate to be expected from this zone during periods of combined flow. The rate from the other zone will be determined by difference.

TABLE 2—CRITICAL FLOW DATA

Surface Tubing Pressure (psi)	Tubing Inlet Pressure (psi)	Liquid Rate (B/D)
700	1,300	50
500	1,050	55
300	825	60
100	600	60

[1]References given at end of paper.

Use Of The Tool In Gas Lifting

The multiple-completion choke assembly, when used as a gas-lift device, is in effect a single-point injection, retrievable flow valve utilizing gas supplied directly from the formation at maximum efficiency. An expert in gas-lift technology, in discussing conventional gas-lift systems,[2] has made the following pertinent observations.

> Which flow process, continuous or intermittent, will yield the greatest amount of produced stock-tank liquid for the least amount of injected gas at the available pressures? The continuous-flow process, if properly instituted, should be inherently more efficient than that of intermittent flow. The gas is put to work as needed and the high dissipation of initial energy in overcoming starting inertia is largely absent. Also, the external work done by the gas is negligible. The fact is, however, that maximum efficiency in the continuous-flow process can only be realized by putting the gas to work as soon as possible. This means high injection pressures at moderate depths. Because the high injection pressures necessary for maximum efficiency are seldom available, it has been found in practice that the intermittent-flow process is frequently more efficient than that of continuous flow, for wells that produce moderate amounts of liquid.
>
> It is significant to point out here that the Phillips paper, previously referred to, lists data from some 34 flowing wells and 16 gas-lift wells (continuous flow). The thermodynamic flow efficiency for the flowing wells was on the order of 85 to 95 per cent, whereas the gas-lift wells were mainly of the order of 40-60 per cent. There is no reason why continuous-flow gas-lift wells should not closely approximate the efficiency of naturally flowing wells, if the installations are correctly designed.
>
> It is recognized that the high-pressure requirements for maximum efficient operations is definitely a limiting factor in any practical well installation. It is most important to recognize that, as injection pressures are decreased below the optimum, the flow efficiency

Well No. 2

Well 2 was completed in May, 1961. The upper zone on drill-stem test was judged to be noncommercial but did produce some oil. This is a situation frequently confronting an operator. A zone looks doubtful on an electric log and a drill-stem test is not conclusive—should he make a single or dual completion? It is a perplexing question. The great expense involved in twin-string duals will not often justify a thorough evaluation of these doubtful zones. On the other hand, he may be passing up a commercial reserve. The multiple-completion choke assembly can be used to good advantage in this situation. Doubtful producing horizons can be fully evaluated at low additional cost and, when combined with good producers, can be depleted without artificial lift. This will result in the recovery of more oil and more gas.

Well 2 is a deep, directionally drilled, high-pressure, high-temperature well—a water location—and provided quite a test for the tool. The wireline operations in this well, however, have gone quite smoothly.

Well No. 3

Well 3 was originally a single-completion oil well. In June, 1961, the oil zone was dualled with a deeper sand productive of gas and condensate.

Table 8 gives the results of single-zone tests of the lower zone; Fig. 4 is a graphic representation of these data. Note that the well goes into critical flow at a tubing inlet pressure of 1,835 psi, or 55 per cent of the upstream pressure of approximately 3,300 psi.

After the tests of the lower zone were concluded, the upper zone was tested and then the two zones were combined. The tubing inlet pressure at 7,550 ft was measured with a bottom-hole pressure gauge and found to be 1,720 psi with a surface tubing pressure of 1,100 psi. As a check, the depth-pressure gradient curves were used to determine the tubing inlet pressure under these conditions of flow. This value was interpolated to be 1,650 psi. The lower zone is in critical flow under these conditions. This means that the predetermined rate of production of the lower zone is not affected by combining with the upper.

Well No. 4

Well 4, a water location, was completed in June, 1961. The upper zone is only 8-ft thick and would not justify the additional cost of a twin-string dual.

Production tests of the lower zone with a 4.5/64-in. choke bean in the orifice head were made as shown in Table 9.

These tests show that the well goes out of critical flow when the surface pressure is increased manually above 250 psi. Plotting oil rate vs tubing pressure locates the critical point at 875 psi.

Following these tests, the orifice head was pulled and run back with the lower zone blanked and a 4.5/64-in. choke bean controlling production from the upper zone. On stabilized test in critical flow, the upper zone produced 152 BOPD (neither zone produces salt water) with a gas-oil ratio of 720 cu ft/bbl.

The orifice head was then pulled and returned with each zone open to a 4.5/64-in. choke bean. Combined production was gauged at 311 BOPD, a good check with the individual zone tests (157 and 152, a total of 309 BOPD).

TABLE 9—WELL DATA, LOWER ZONE, WELL NO. 4

Oil Production (B/D)	Gas-Oil Ratio (cu ft/bbl)	Surface Tubing Pressure (psi)
156	827	150
158	919	150
157	936	250
149	905	975
138	972	1,075
122	957	1,200
100	900	1,450

Well No. 5 Through 7

Well 5 was a singly-completed, deficient oil well when it was dually-completed in Aug., 1961, with a gas zone. The oil zone was not good enough to support a twin-string completion and would have been abandoned had not the multiple-completion choke assembly been available.

Well 6, a water location, was completed in Aug., 1961, and has been produced without incident.

Well 7, another water location, was completed in Aug., 1961. Tests show that both zones are in critical flow. Each zone was tested separately. The lower zone made 65 BOPD, and the upper zone was tested at 71 BOPD. When combined, the two zones produced 132 BOPD.

Well No. 8

Well 8, the first test in Texas, was worked-over and completed as a dual in Oct., 1961. This well is completed in a low-pressure gas sand and a low-pressure oil sand. The gas is used to lower the gradient in the well to allow flow from the oil zone. The low bottom-hole pressure existing in the gas

TABLE 7—INDIVIDUAL TEST DATA FOR UPPER ZONE, WELL NO. 1—LOWER ZONE BLANKED-OFF

Date	Choke Size (in.)	Production Oil (B/D)	Production Gas (Mcf/D)
7-24-60	5/64	7.23	248
10-5-60	6/64	7.80	227
10-18-60	5/64	7.80	227
12-4-60	5/64	7.23	209
1-27-61	3.5/64	6.38	175
5-29-61	3.5/64	6.96	150

TABLE 8—INDIVIDUAL TEST DATA OF LOWER ZONE, WELL NO. 3—UPPER ZONE BLANKED-OFF

Tubing Pressure (psig) Surface	Tubing Pressure (psig) Inlet	Production Condensate (B/D)	Production Gas (Mcf/D)
790	1,466	38.40	726,802
950	1,549	39.41	726,802
1,060	1,835	37.34	708,654
1,250	2,091	32.12	638,787
1,335	2,345	30.06	555,196
1,475	2,517	22.82	454,251
1,600	3,125	12.44	222,078

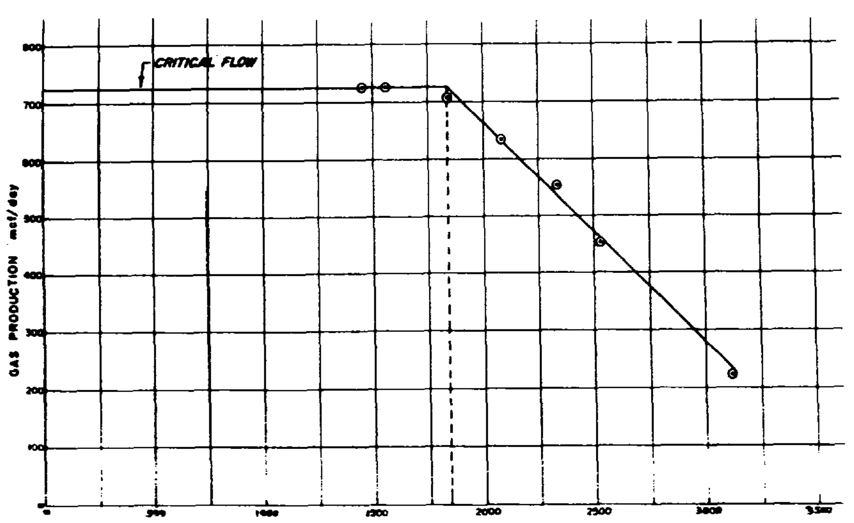

Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

sand will not justify the surface facilities that would be required for the sale of the gas, nor will the low pressure justify the use of this gas in a conventional gas-lift system.

A new check valve received its first subsurface test in Well 8. Results were quite encouraging, and the valve subsequently has been used in other wells. The lower zone in Well 8 was acidized with the new check valve protecting the upper zone. The treatment was successful mechanically, and the check valve functioned perfectly. Maximum differential pressure across the check valve during acidizing was 4,000 psi.

This new check valve is a sleeve-type steel valve incorporating both a metal-to-metal and an O-ring seal. In time, it may replace entirely the resilient-type check valve.

The required packer-leakage test in Well 8 was obtained by blanking-off the upper zone in the orifice head and flowing the upper zone through the casing. The lower zone was open to the tubing. The casing and tubing pressures were recorded simultaneously. This is the method for obtaining a packer-leakage test when there is no packer set above the upper zone. If the upper packer is set, packer-leakage tests can be made by measuring the bottom-hole pressure of one zone while flowing the other. A device is now available which will allow a bottom-hole pressure element to be run with the orifice-head assembly. The shut-in bottom-hole pressure of one zone is measured while the other is open to flow. This type of packer-leakage test should be more realistic than the conventional test where surface pressure fluctuations are observed.

Allocation tests in Well 8 are made by blanking-off the lower zone and measuring the gas produced from the upper zone through the tubing. The two zones are then combined and the increase in gas rate is calculated from the orifice-meter chart. This increase represents the volume of gas produced from the lower zone. All liquids produced are known to have come from the lower zone, as the upper zone produces dry gas. The tubing inlet pressure is measured. The results show that the upper zone is in critical flow. This means that production from the lower zone has no effect on the predetermined rate from the upper zone.

It can be argued that this method of gas measurement is considerably more accurate than the usual method of measuring gas into and out of a conventional, intermitting-type gas-lift well.

Economics

Use of the multiple-completion choke assembly to produce two reservoirs simultaneously through a single flow string results in an initial saving in equipment and rig costs, and in later workover costs, when compared with twin-string duals.

The savings possible cover a wide range. For example, the equipment costs of Well 6 are compared with those of a twin-string dual in the same field, on a comparative-footage basis, in Table 10. This represents a difference of $42,131 and includes neither the saving in rig time nor the considerable saving in workover costs which may result. Anyone who has worked-over a deep twin-string dual in a water location will attest—perhaps grimly—to the costs that can be incurred in such operations.

At the other end of the scale, in the relatively shallow wells, a cost comparison between tubular requirements in three different types of dual completions is shown in Table 11.

Initial completion operations conceivably might result in the tubingless-completion dual costing more than the single-string dual.

Simplicity and flexibility always should be taken into account when planning the system that will produce the most hydrocarbons for the least money.

The wireline expense associated with the simultaneous, one-flow-string method will depend primarily upon operator skill, accessibility of location, depth and testing requirements. This expense will be relatively high for the first month or two, and then will taper off. Wireline costs for the year 1961 in Well 1 have averaged $65 per month. In many wells, as in Well 1, the wireline expense will be more than compensated for by increased production, reduced lifting costs and greater ultimate recovery.

TABLE 10 — TUBULAR-GOODS COST OF TWIN-STRING VS SINGLE-STRING DUAL COMPLETION

	Well "X"	Well No. 6
Conductor	$ 788 (20 in.)	$ 538 (16 in.)
Surface	13,981 (11¾ in.)	11,200 (10¾ in.)
Oil String	61,500 (7⅝ in.)	39,600 (5½ in.)
Tubing	27,000 (2⅜ in.)	11,200 (2⅜ in.)
Wellhead Costs	5,200	3,800
Total	$108,469	$66,338

Acceptance By Regulatory Agencies

Permission to use the multiple-completion choke assembly in Well 1 was granted by the Louisiana Conservation Commission on a six-month basis, and then extended permanently for that particular well. Approval for the other two Kinder wells was obtained after a public hearing. The hearing was necessary because the lower producing sand was unitized and created a diversity of ownership in those wells.

Approval for the other Louisiana installations has been obtained after filing a routine request for permission to dually complete, with the provision that a review of the well be made after a six-month operational period.

In Texas, the Railroad Commission has been somewhat stymied by Statewide Rule 15, which says "No well shall be permitted to produce oil and/or gas from different strata through the same string of casing".

This rule was written some 27 years ago to prevent an operator from indiscriminately opening two or more zones in the same wellbore, and commingling this production without regulation or proper identification as to source.

The Railroad Commission, after a public hearing, granted an exception to Rule 15 in the case of Well 8. It was emphasized at the hearing that the old concept of commingling did not apply to wells equipped with the multiple-completion choke assembly, and that there was no basic difference between this and conventional methods inasmuch as commingling occurred *after* regulation, as it does in any tank battery where surface commingling takes place.

There are really no statutory obstacles to Railroad Commission acceptance of this producing method. Opinion No. 0-2245 concerning "The right of an operator to utilize gas produced from an upper horizon in lifting the oil produced from an oil sand at a lower horizon, without first producing the gas at the surface", was approved on May 20, 1940, by Texas Attorney General Mann and by his Opinion Committee. They ruled as follows: "So long as the proper steps are

TABLE 11—TUBULAR-GOODS COST OF SINGLE-STRING VS TWIN-STRING AND TUBINGLESS COMPLETION

	Twin String			Tubingless			Single String		
	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost
Surface	500	9⅝	$ 1,750	500	9⅝	$1,750	500	9⅝	$ 1,750
Oil String	4,600	7	9,450	9,000	2⅞	7,450	4,600	5½	6,750
Tubing	9,000	2⅜	5,600	None	—	—	4,500	2⅜	2,800
Total			$16,800			$9,200			$11,300

taken to insure against the escape of oil or gas from one stratum into another, we do not believe that the statutes prevent the Commission from permitting the more efficient method of introducing the gas into the tubing below the surface, instead of requiring that the gas first be brought to the surface through a separate string of casing and then reintroduced into the well".

Other Applications

Use of the multiple-completion choke assembly is not limited to the applications that have been described. For example, the device is ideally suited to dual gas wells, and is being used in such wells in Mexico. Other, more specialized, installations are illustrated in Figs. 5 through 10. The single-string dual tubingless completion shown in Fig. 10 must surely represent the final stage in the reduction of initial equipment costs for dual completions.

Operational Suggestions

Following are some suggestions to those who contemplate using the multiple-completion choke assembly.

1. Set tubing with as little compression as possible to facilitate wireline operations.

2. Install the side-door choke in the landing nipple when the tubing is run to permit washing the well around the bottom of the tubing.

3. Pull the side-door choke and clean both zones before running the check-valve assembly, unless the differential in bottom-hole pressures is too great.

4. Use a wireline operator experienced in the operation of the multiple-completion choke assembly. Be sure he has good equipment on the job, including a sensitive weight indicator.

5. If the lower zone is protected by a check valve, do not run the orifice head with a blank in the opening communicating with the lower zone. This is similar to forcing a piston into a closed cylinder containing liquid, and will cause destruction of the O-ring seals on the tube and possible bending of the tube. This situation arises only when the lower zone is the weak zone and requires a check valve. Under these circumstances, when a test is made of the upper zone alone, the O-rings should be left off the tube of the orifice-head assembly. The higher pressure of the upper zone acting against the check valve of the lower zone will prevent flow from the lower zone.

6. Take extra precautions to assure accurate measurement of the fluids produced during tests. This is very important and should be stressed with field personnel.

7. For especially severe service, the metal sleeve-type check valve with an O-ring seal is recommended.

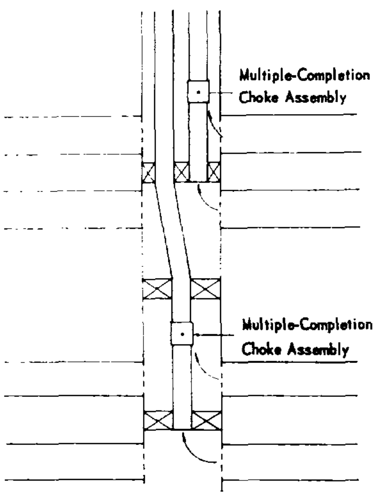

Fig. 5—Two-string quadruple completion.

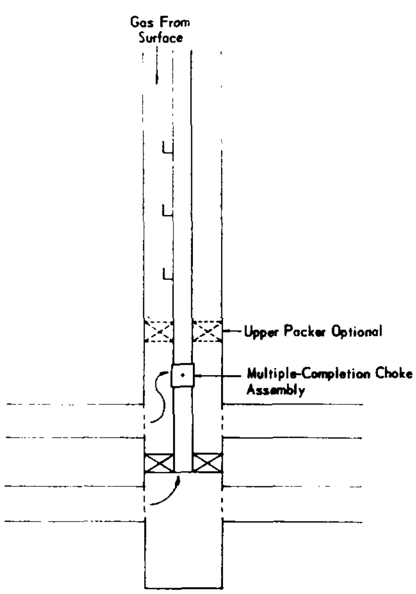

Fig. 6—Gas-lifting two zones with one string of flow valves.

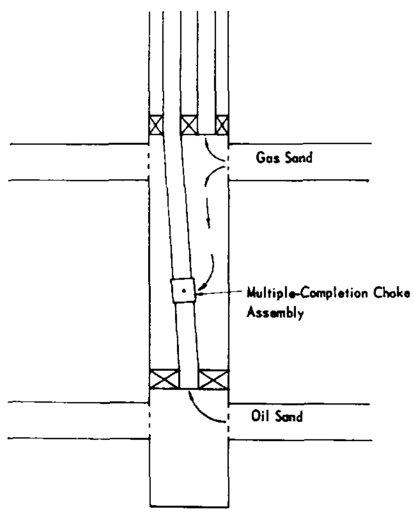

Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

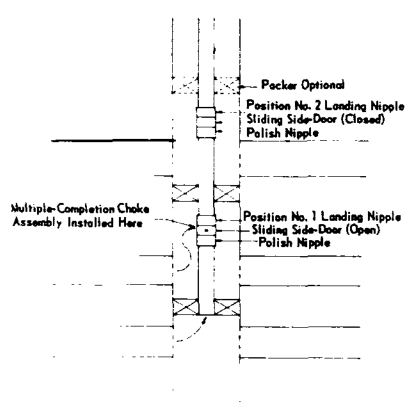

Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

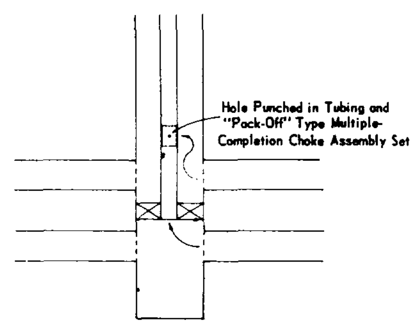

Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

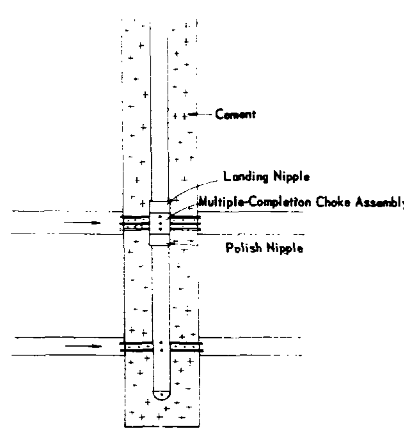

Fig. 10—One-string dual tubingless completion.

Future Development

The future development of the multiple-completion choke assembly and the method of simultaneous production through a single flow string is projected along the following two lines.

1. Surface-recorded bottom-hole pressures will be used to facilitate allocation and packer-leakage tests. A large portion of the wireline work could be eliminated if one had knowledge of the two pressures upstream from the choke and the tubing inlet pressure.

2. Informative material will be presented to state regulatory agencies in an effort to secure general acceptance of the process. This is largely a matter of demonstrating the feasibility of the method, both legally and mechanically, and showing that it will effect conservation and prevent waste.

Conclusions

Simultaneous production of two reservoirs through a single flow string can result in a significant reduction in completion and lifting costs, and will increase current income and ultimate recovery. The multiple-completion choke assembly can be used to maintain separation of the reservoirs and to control the rate of production from each. Test procedures have been developed which provide an acceptable method of determining the contribution from each zone. All requirements imposed by the various regulatory agencies can be satisfied.

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★★★

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New Tool Permits Simultaneous Production of Two Reservoirs Through the Same Flow String

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Abstract

The constant search for methods to increase the efficiency of production systems and to reduce operating costs has led to the development of a wireline tool which makes it possible to produce and control two separate reservoirs through a single string of tubing. This paper is a progress report of the experience one company has gained with this tool in eight of its dually completed wells in Louisiana and Texas. Field tests have clearly demonstrated that this device can be used to maintain separation of production from two reservoirs, to control and determine the rate of production from each, and to change the rate of production as required. The advantages in simultaneous one-string multiple completions are enumerated, and various applications of the method are discussed.

Introduction

It is now almost standard operating procedure to complete wells in more than one zone wherever possible, with the great majority of these multiples being dual completions. This is a sign of the times. Saving must be accomplished wherever possible; however, there is no need to expand on this theme. All are painfully aware of the economic conditions within the industry. It is sufficient to say that the practice of multiple completions is here to stay and is becoming more popular every day. The only question is whether or not the practice has evolved into its most acceptable form.

The earlier duals were the concentric type, with one zone producing through the tubing and the other through the tubing-casing annulus. This method is still practiced to a large degree. It is popular because it is relatively inexpensive. Unfortunately, it has some rather severe limitations, with which the reader undoubtedly is familiar.

The twin-string dual is an improvement over the concentric in the sense that many of the problems associated with the concentric have been solved. The objectionable features of the twin-string dual are the high cost of equipping the well with an extra string of tubing, plus accessories, and the complications brought on by cramming all this tubing into one string of casing.

Still another type of multiple is the tubingless completion, wherein two or more small casing strings are cemented in place and subsequent operations performed with miniaturized equipment.

The purpose of this paper is to present a different concept in multiple completion—the simultaneous production of separate reservoirs in a single flow string. This method combines the simplicity and low cost of the concentric with the flexibility of the twin-string dual. In addition, it provides the unique advantage of prolonging natural flow from a low-pressure zone by combining its production with the fluids produced from a higher-pressure zone. The wireline tool which makes this method possible is the multiple-completion choke assembly.

Construction and Operation of the Multiple-Completion Choke Assembly

Fig. 1 shows a well properly equipped to receive a multiple-completion choke assembly. A conventional packer separates the two producing zones. The upper packer is optional. A side-door choke landing-nipple hookup is located in the tubing

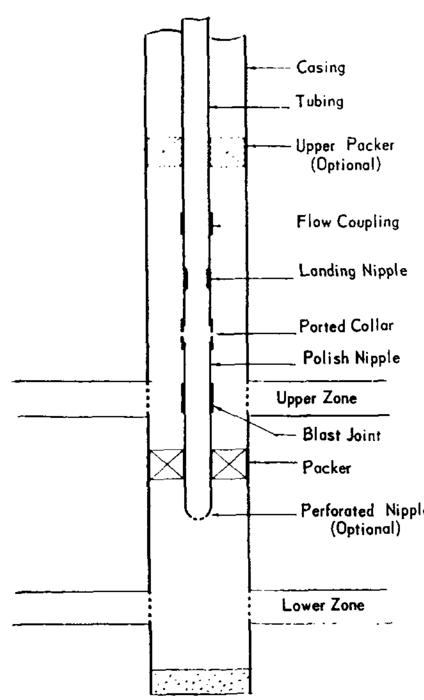

Fig. 1—Well properly equipped for multiple-completion choke assembly.

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string above the lower packer. The multiple-completion choke assembly will be locked in this landing nipple. Normally located a joint or two above the upper zone, the position of the landing-nipple hookup can be varied to suit well conditions. For example, where the two zones are widely separated, it might be placed just above the lower packer to facilitate bottom-hole pressure tests of the lower zone.

The tool consists of two separate assemblies. The outer assembly, which is run independently and locked in the landing nipple, contains the check valves and packing seals which prevent flow from one zone to the other. In practice, however, only one check valve is usually required and is installed to protect the zone with the lower pressure.

The orifice-head assembly, which carries the tungsten-carbide choke beans, is run separately and is seated and locked in the outer assembly. The method of running each section is illustrated in Fig. 2.

Fig. 3 is a schematic drawing which shows more clearly how the device works. Production from the lower zone enters the assembly through a slotted section, flows around a resilient sleeve-type check valve, enters, and flows through the tube of the orifice-head assembly; it is choked and—now regulated—flows into the tubing. Produced fluids from the upper zone enter the casing opposite a blast joint on the tubing, flow through the ported collar of the side-door choke landing-nipple hookup, through the upper slotted secion, around the upper check valve, into the annulus surrounding the tube and through the upper-zone choke bean into the tubing. Here the two controlled flow streams, which have been kept separate up to this point, combine and flow to the surface.

Tubing Inlet Pressure

The pressure in the tubing at the junction of the two streams will be the minimum pressure required to lift the combined fluids to the surface (at zero surface pressure) and will be determined essentially by the gas-liquid ratio, production rate and tubing size. This pressure, which will hereafter be referred to as the "tubing inlet pressure", is of particular interest because of its importance in the application of the multiple-completion choke assembly. For example, suppose that investigation is being made into the possibility of using the assembly in a two-zone oil well with characteristics as tabulated in Table 1.

The combined production rate is 160 B/D of liquid (including salt water) and 87 Mcf/D of gas. The combined gas-liquid ratio is 543 cu ft/bbl. With a multiple-completion choke assembly set at 6,500 ft in 2⅜-in. OD tubing, it can be determined from published depth-pressure gradient curves[1] that the tubing inlet pressure will be approximately 850 psi.

The upper zone, with a productivity index of 0.5, will produce 96 B/D of liquid with a flowing bottom-hole

TABLE 1—WELL DATA USED IN EVALUATING APPLICATION OF MULTIPLE-COMPLETION TOOL

	Upper Zone	Lower Zone
Producing Depths (ft)	6,600	7,200
Static BHP (psi)	1,500	3,400
Productivity Index (B/D/psi drop)	0.5	1.0
Oil Produced (B/D)	56	64
Salt Water Produced (B/D)	40	None
Gas Produced (Mcf/D)	39	48
Gas-Liquid Ratio	406	750

pressure of approximately 1,308 psi. Since the flowing bottom-hole pressure of the weaker zone is greater than the tubing inlet pressure at the desired rate of production, this well can be produced by natural flow with a multiple-completion choke assembly. Natural flow will be maintained so long as the flowing bottom-hole pressure of the weaker zone (in this example, the upper zone) exceeds the tubing inlet pressure. At some point in the life of the upper zone, however, conditions favorable for natural flow *as a single completion* would no longer prevail. In other words, if it were being produced independently, some form of artificial lift would be required. The requirement is postponed because of the availability of the gas from the lower zone. When the lower zone can no longer "carry" the upper, a single set of flow valves can be run to produce both zones through the multiple-completion choke assembly.

Allocation of Production

Allocation of fluids produced from each zone is based on a separate, individual zone test. To obtain such a test, the orifice-head assembly is removed from the check-valve assembly and brought to the surface with conventional wireline tools. (Removal of

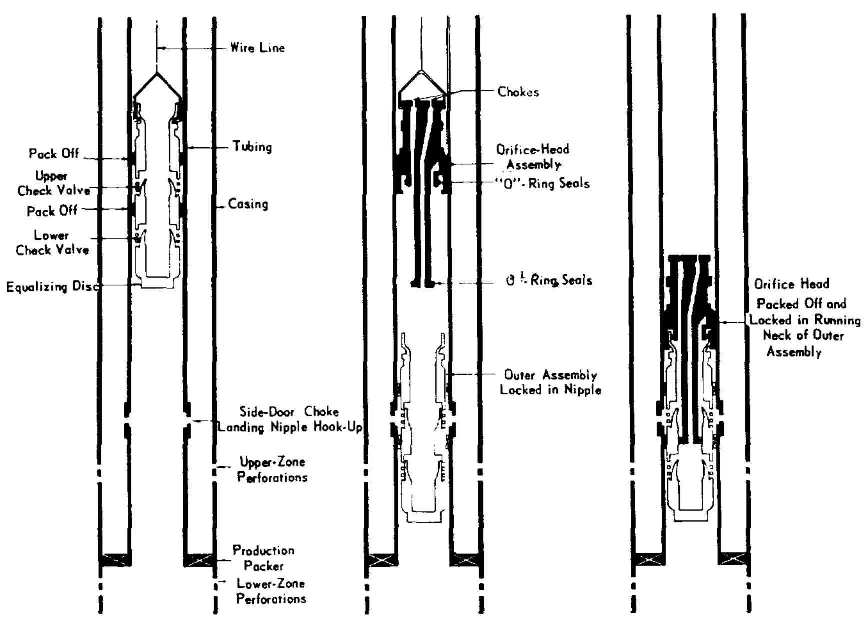

Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

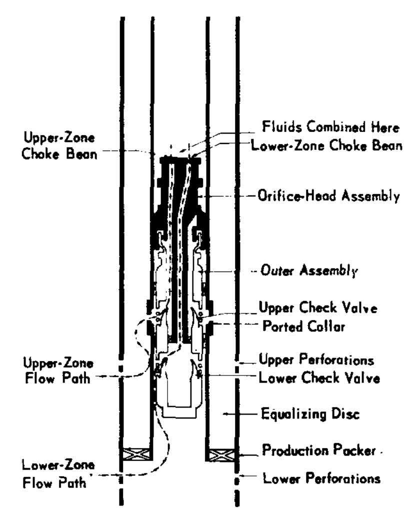

Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

the orifice head does not result in interzone flow, as the check-valve assembly remains in the well.) If the lower zone is to be tested, a blank bean is inserted in the opening in the orifice head communicating with the flow path of the upper zone. A choke bean, properly sized[1] to produce the desired volume of fluid from the lower zone, is placed in the opposite side of the orifice head. The orifice head is then lowered into the well, and landed and locked in the check-valve assembly. The upper zone cannot flow because of the blank choke bean. Produced fluids from the lower zone are measured into conventional surface facilities until a stabilized 24-hour test is obtained. The orifice head is again removed from the well. The blank bean is replaced with a production bean, and the assembly is returned to its operating position in the well. A stabilized test of the combined fluids produced is obtained. The predetermined rate from the lower zone is subtracted from the combined total, with the difference assigned to the upper zone.

The test procedure used will be determined by the flow conditions present in the well—specifically, whether or not one of the zones is in critical flow. A stream is said to be in critical flow when alterations in pressure downstream from an orifice do not affect the rate of flow through the orifice. The critical point occurs when the downstream pressure is 53 per cent of the upstream pressure. The significance of this phenomenon in the operation of the multiple-completion choke assembly is that, if one of the zones is in critical flow and the other is not, the zone not in critical flow can be regulated with a surface control without affecting the rate from the other. In the well described earlier, for example, if the tubing inlet pressure is not allowed to exceed approximately 1,765 psi (53 per cent of 3,336 psi), the rate from the lower zone will not be affected. In other words, back-pressure at the surface can be increased to the point of actually shutting-in the upper zone, with no effect on the rate from the lower zone.

In any well where two reservoirs are being produced simultaneously through the multiple-completion choke assembly, one of the following three conditions will exist: (1) one zone will be in critical flow; (2) neither zone will be in critical flow; or (3) both zones will be in critical flow. The method of testing for allocation will depend upon which one of these conditions exists.

The exact value of the critical P_2/P_1 ratio, whether it be 53 per cent or some other value, is of no particular concern. The ratio is not used quantitatively. As a matter of interest, however, in the wells where this critical point has been observed, the value has appeared reasonably close to 53 per cent.

The exact point of critical flow can be determined by changing the surface tubing pressure with an adjustable choke, measuring the rate of flow into conventional test facilities and observing the effect of the back-pressure changes.

At the same time, the tubing inlet pressure is measured with a bottom-hole pressure gauge. For example, tests run on a certain zone in a dual completion might result in the data shown in Table 2.

These data show the stream is going into critical flow between a tubing inlet pressure of 1,050 and 825 psi. This point can be determined more precisely if the results are shown graphically, as will be illustrated later in actual well tests.

A predetermined rate for this particular zone on a specific choke size for this range of tubing inlet pressures has now been established. It makes no difference what effect, if any, the second zone may have on the tubing inlet pressure in the well. Because this pressure can be determined, the rate from the first zone will be known. The difference is then assigned to the zone not tested individually, usually the lower-pressure zone.

If each zone can produce its allowable independently of the other, there may be some reason to test each separately. This procedure, of course, will require additional wireline work and is not essential in determining the production from each zone. The method has been used occasionally to demonstrate the consistency of flow-rate control possible with the choke beans in the tool.

Summarizing, production tests will follow one of two patterns. If either or both of the two zones is in critical flow when combined, a 24-hour stabilized test of the zone with the higher pressure is obtained. Back-pressure is not adjusted during this test. Following this, both zones are combined and tested for 24 hours at a stabilized rate. The difference in production is known to have come from the zone not tested singly.

If neither of the zones is in critical flow, the zone with the higher pressure is tested individually. The surface pressure is varied and the stabilized rates of production at the various back-pressures are measured. Tubing inlet pressure is recorded with a bottom-hole pressure gauge. This test predetermines the rate to be expected from this zone during periods of combined flow. The rate from the other zone will be determined by difference.

TABLE 2—CRITICAL FLOW DATA

Surface Tubing Pressure (psi)	Tubing Inlet Pressure (psi)	Liquid Rate (B/D)
700	1,300	50
500	1,050	55
300	825	60
100	600	60

[1]References given at end of paper.

Use Of The Tool In Gas Lifting

The multiple-completion choke assembly, when used as a gas-lift device, is in effect a single-point injection, retrievable flow valve utilizing gas supplied directly from the formation at maximum efficiency. An expert in gas-lift technology, in discussing conventional gas-lift systems,[2] has made the following pertinent observations.

> Which flow process, continuous or intermittent, will yield the greatest amount of produced stock-tank liquid for the least amount of injected gas at the available pressures? The continuous-flow process, if properly instituted, should be inherently more efficient than that of intermittent flow. The gas is put to work as needed and the high dissipation of initial energy in overcoming starting inertia is largely absent. Also, the external work done by the gas is negligible. The fact is, however, that maximum efficiency in the continuous-flow process can only be realized by putting the gas to work as soon as possible. This means high injection pressures at moderate depths. Because the high injection pressures necessary for maximum efficiency are seldom available, it has been found in practice that the intermittent-flow process is frequently more efficient than that of continuous flow, for wells that produce moderate amounts of liquid.

> It is significant to point out here that the Phillips paper, previously referred to, lists data from some 34 flowing wells and 16 gas-lift wells (continuous flow). The thermodynamic flow efficiency for the flowing wells was on the order of 85 to 95 per cent, whereas the gas-lift wells were mainly of the order of 40-60 per cent. There is no reason why continuous-flow gas-lift wells should not closely approximate the efficiency of naturally flowing wells, if the installations are correctly designed.

> It is recognized that the high-pressure requirements for maximum efficient operations is definitely a limiting factor in any practical well installation. It is most important to recognize that, as injection pressures are decreased below the optimum, the flow efficiency

Well No. 2

Well 2 was completed in May, 1961. The upper zone on drill-stem test was judged to be noncommercial but did produce some oil. This is a situation frequently confronting an operator. A zone looks doubtful on an electric log and a drill-stem test is not conclusive—should he make a single or dual completion? It is a perplexing question. The great expense involved in twin-string duals will not often justify a thorough evaluation of these doubtful zones. On the other hand, he may be passing up a commercial reserve. The multiple-completion choke assembly can be used to good advantage in this situation. Doubtful producing horizons can be fully evaluated at low additional cost and, when combined with good producers, can be depleted without artificial lift. This will result in the recovery of more oil and more gas.

Well 2 is a deep, directionally drilled, high-pressure, high-temperature well—a water location—and provided quite a test for the tool. The wireline operations in this well, however, have gone quite smoothly.

Well No. 3

Well 3 was originally a single-completion oil well. In June, 1961, the oil zone was dualled with a deeper sand productive of gas and condensate.

Table 8 gives the results of single-zone tests of the lower zone; Fig. 4 is a graphic representation of these data. Note that the well goes into critical flow at a tubing inlet pressure of 1,835 psi, or 55 per cent of the upstream pressure of approximately 3,300 psi.

After the tests of the lower zone were concluded, the upper zone was tested and then the two zones were combined. The tubing inlet pressure at 7,550 ft was measured with a bottom-hole pressure gauge and found to be 1,720 psi with a surface tubing pressure of 1,100 psi. As a check, the depth-pressure gradient curves were used to determine the tubing inlet pressure under these conditions of flow. This value was interpolated to be 1,650 psi. The lower zone is in critical flow under these conditions. This means that the predetermined rate of production of the lower zone is not affected by combining with the upper.

Well No. 4

Well 4, a water location, was completed in June, 1961. The upper zone is only 8-ft thick and would not justify the additional cost of a twin-string dual.

Production tests of the lower zone with a 4.5/64-in. choke bean in the orifice head were made as shown in Table 9.

These tests show that the well goes out of critical flow when the surface pressure is increased manually above 250 psi. Plotting oil rate vs tubing pressure locates the critical point at 875 psi.

Following these tests, the orifice head was pulled and run back with the lower zone blanked and a 4.5/64-in. choke bean controlling production from the upper zone. On stabilized test in critical flow, the upper zone produced 152 BOPD (neither zone produces salt water) with a gas-oil ratio of 720 cu ft/bbl.

The orifice head was then pulled and returned with each zone open to a 4.5/64-in. choke bean. Combined production was gauged at 311 BOPD, a good check with the individual zone tests (157 and 152, a total of 309 BOPD).

TABLE 9—WELL DATA, LOWER ZONE, WELL NO. 4

Oil Production (B/D)	Gas-Oil Ratio (cu ft/bbl)	Surface Tubing Pressure (psi)
156	827	150
158	919	150
157	936	250
149	905	975
133	972	1,075
122	957	1,200
100	900	1,450

Well No. 5 Through 7

Well 5 was a singly-completed, deficient oil well when it was dually-completed in Aug., 1961, with a gas zone. The oil zone was not good enough to support a twin-string completion and would have been abandoned had not the multiple-completion choke assembly been available.

Well 6, a water location, was completed in Aug., 1961, and has been produced without incident.

Well 7, another water location, was completed in Aug., 1961. Tests show that both zones are in critical flow. Each zone was tested separately. The lower zone made 65 BOPD, and the upper zone was tested at 71 BOPD. When combined, the two zones produced 132 BOPD.

Well No. 8

Well 8, the first test in Texas, was worked-over and completed as a dual in Oct., 1961. This well is completed in a low-pressure gas sand and a low-pressure oil sand. The gas is used to lower the gradient in the well to allow flow from the oil zone. The low bottom-hole pressure existing in the gas

TABLE 7—INDIVIDUAL TEST DATA FOR UPPER ZONE, WELL NO. 1—LOWER ZONE BLANKED-OFF

Date	Choke Size (in.)	Production: Oil (B/D)	Production: Gas (Mcf/D)
7-24-60	5/64	7.23	248
10-5-60	6/64	7.80	227
10-18-60	5/64	7.80	227
12-4-60	5/64	7.23	209
1-27-61	3.5/64	6.38	175
5-29-61	3.5/64	6.96	150

TABLE 8—INDIVIDUAL TEST DATA OF LOWER ZONE, WELL NO. 3—UPPER ZONE BLANKED-OFF

Tubing Pressure (psig)		Production	
Surface	Inlet	Condensate (B/D)	Gas (Mcf/D)
790	1,466	38.40	726,802
950	1,549	39.41	726,802
1,060	1,835	37.34	708,654
1,250	2,091	32.12	638,787
1,335	2,345	30.06	555,196
1,475	2,517	22.82	454,251
1,600	3,125	12.44	222,078

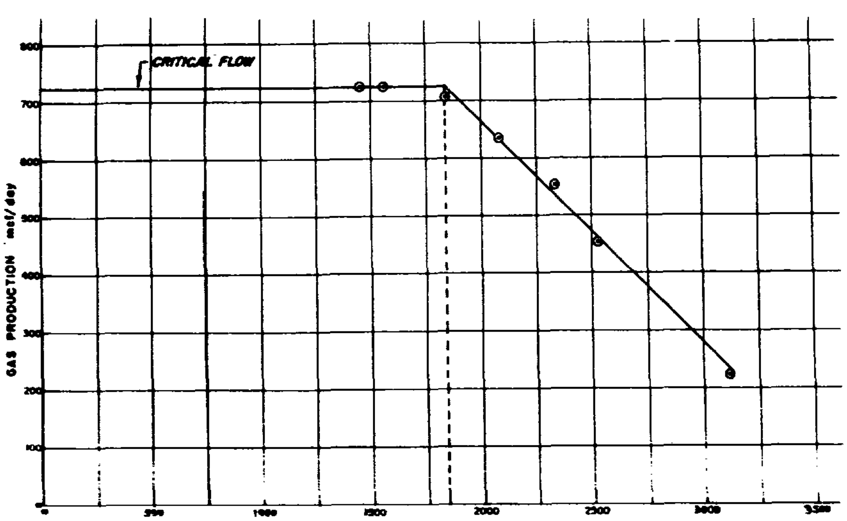

Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

sand will not justify the surface facilities that would be required for the sale of the gas, nor will the low pressure justify the use of this gas in a conventional gas-lift system.

A new check valve received its first subsurface test in Well 8. Results were quite encouraging, and the valve subsequently has been used in other wells. The lower zone in Well 8 was acidized with the new check valve protecting the upper zone. The treatment was successful mechanically, and the check valve functioned perfectly. Maximum differential pressure across the check valve during acidizing was 4,000 psi.

This new check valve is a sleeve-type steel valve incorporating both a metal-to-metal and an O-ring seal. In time, it may replace entirely the resilient-type check valve.

The required packer-leakage test in Well 8 was obtained by blanking-off the upper zone in the orifice head and flowing the upper zone through the casing. The lower zone was open to the tubing. The casing and tubing pressures were recorded simultaneously. This is the method for obtaining a packer-leakage test when there is no packer set above the upper zone. If the upper packer is set, packer-leakage tests can be made by measuring the bottom-hole pressure of one zone while flowing the other. A device is now available which will allow a bottom-hole pressure element to be run with the orifice-head assembly. The shut-in bottom-hole pressure of one zone is measured while the other is open to flow. This type of packer-leakage test should be more realistic than the conventional test where surface pressure fluctuations are observed.

Allocation tests in Well 8 are made by blanking-off the lower zone and measuring the gas produced from the upper zone through the tubing. The two zones are then combined and the increase in gas rate is calculated from the orifice-meter chart. This increase represents the volume of gas produced from the lower zone. All liquids produced are known to have come from the lower zone, as the upper zone produces dry gas. The tubing inlet pressure is measured. The results show that the upper zone is in critical flow. This means that production from the lower zone has no effect on the predetermined rate from the upper zone.

It can be argued that this method of gas measurement is considerably more accurate than the usual method of measuring gas into and out of a conventional, intermitting-type gas-lift well.

Economics

Use of the multiple-completion choke assembly to produce two reservoirs simultaneously through a single flow string results in an initial saving in equipment and rig costs, and in later workover costs, when compared with twin-string duals.

The savings possible cover a wide range. For example, the equipment costs of Well 6 are compared with those of a twin-string dual in the same field, on a comparative-footage basis, in Table 10. This represents a difference of $42,131 and includes neither the saving in rig time nor the considerable saving in workover costs which may result. Anyone who has worked-over a deep twin-string dual in a water location will attest—perhaps grimly—to the costs that can be incurred in such operations.

At the other end of the scale, in the relatively shallow wells, a cost comparison between tubular requirements in three different types of dual completions is shown in Table 11.

Initial completion operations conceivably might result in the tubingless-completion dual costing more than the single-string dual.

Simplicity and flexibility always should be taken into account when planning the system that will produce the most hydrocarbons for the least money.

The wireline expense associated with the simultaneous, one-flow-string method will depend primarily upon operator skill, accessibility of location, depth and testing requirements. This expense will be relatively high for the first month or two, and then will taper off. Wireline costs for the year 1961 in Well 1 have averaged $65 per month. In many wells, as in Well 1, the wireline expense will be more than compensated for by increased production, reduced lifting costs and greater ultimate recovery.

TABLE 10 — TUBULAR-GOODS COST OF TWIN-STRING VS SINGLE-STRING DUAL COMPLETION

	Well "X"	Well No. 6
Conductor	$ 788 (20 in.)	$ 538 (16 in.)
Surface	13,981 (11¾ in.)	11,200 (10¾ in.)
Oil String	61,500 (7⅝ in.)	39,600 (5½ in.)
Tubing	27,000 (2⅜ in.)	11,200 (2⅜ in.)
Wellhead Costs	5,200	3,800
Total	$108,469	$66,338

Acceptance By Regulatory Agencies

Permission to use the multiple-completion choke assembly in Well 1 was granted by the Louisiana Conservation Commission on a six-month basis, and then extended permanently for that particular well. Approval for the other two Kinder wells was obtained after a public hearing. The hearing was necessary because the lower producing sand was unitized and created a diversity of ownership in those wells.

Approval for the other Louisiana installations has been obtained after filing a routine request for permission to dually complete, with the provision that a review of the well be made after a six-month operational period.

In Texas, the Railroad Commission has been somewhat stymied by Statewide Rule 15, which says "No well shall be permitted to produce oil and/or gas from different strata through the same string of casing".

This rule was written some 27 years ago to prevent an operator from indiscriminately opening two or more zones in the same wellbore, and commingling this production without regulation or proper identification as to source.

The Railroad Commission, after a public hearing, granted an exception to Rule 15 in the case of Well 8. It was emphasized at the hearing that the old concept of commingling did not apply to wells equipped with the multiple-completion choke assembly, and that there was no basic difference between this and conventional methods inasmuch as commingling occurred *after* regulation, as it does in any tank battery where surface commingling takes place.

There are really no statutory obstacles to Railroad Commission acceptance of this producing method. Opinion No. 0-2245 concerning "The right of an operator to utilize gas produced from an upper horizon in lifting the oil produced from an oil sand at a lower horizon, without first producing the gas at the surface", was approved on May 20, 1940, by Texas Attorney General Mann and by his Opinion Committee. They ruled as follows: "So long as the proper steps are

TABLE 11—TUBULAR-GOODS COST OF SINGLE-STRING VS TWIN-STRING AND TUBINGLESS COMPLETION

	Twin String			Tubingless			Single String		
	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost	Length (ft)	Size (in.)	Cost
Surface	500	9⅝	$ 1,750	500	9⅝	$1,750	500	9⅝	$ 1,750
Oil String	4,600	7	9,450	9,000	2⅞	7,450	4,600	5½	6,750
Tubing	9,000	2⅜	5,600	None	—	—	4,500	2⅜	2,800
Total			$16,800			$9,200			$11,30G

taken to insure against the escape of oil or gas from one stratum into another, we do not believe that the statutes prevent the Commission from permitting the more efficient method of introducing the gas into the tubing below the surface, instead of requiring that the gas first be brought to the surface through a separate string of casing and then reintroduced into the well".

Other Applications

Use of the multiple-completion choke assembly is not limited to the applications that have been described. For example, the device is ideally suited to dual gas wells, and is being used in such wells in Mexico. Other, more specialized, installations are illustrated in Figs. 5 through 10. The

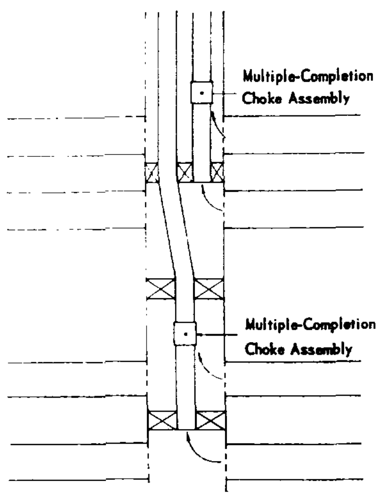

Fig. 5—Two-string quadruple completion.

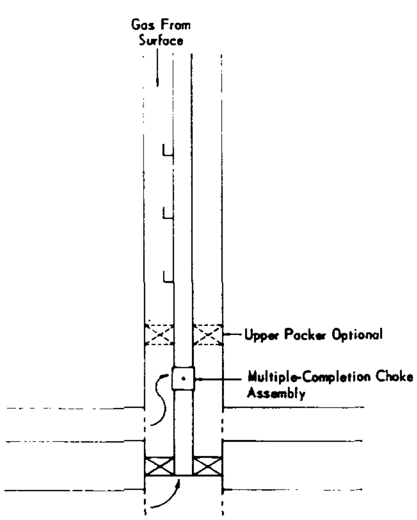

Fig. 6—Gas-lifting two zones with one string of flow valves.

single-string dual tubingless completion shown in Fig. 10 must surely represent the final stage in the reduction of initial equipment costs for dual completions.

Operational Suggestions

Following are some suggestions to those who contemplate using the multiple-completion choke assembly.

1. Set tubing with as little compression as possible to facilitate wireline operations.

2. Install the side-door choke in the landing nipple when the tubing is run to permit washing the well around the bottom of the tubing.

3. Pull the side-door choke and clean both zones before running the check-valve assembly, unless the differential in bottom-hole pressures is too great.

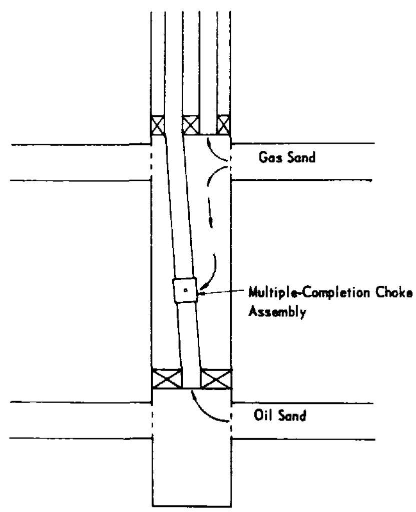

Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

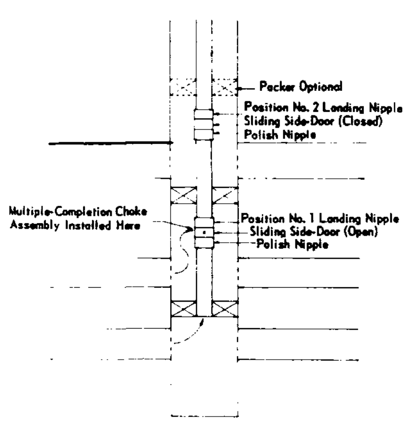

Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

4. Use a wireline operator experienced in the operation of the multiple-completion choke assembly. Be sure he has good equipment on the job, including a sensitive weight indicator.

5. If the lower zone is protected by a check valve, do not run the orifice head with a blank in the opening communicating with the lower zone. This is similar to forcing a piston into a closed cylinder containing liquid, and will cause destruction of the O-ring seals on the tube and possible bending of the tube. This situation arises only when the lower zone is the weak zone and requires a check valve. Under these circumstances, when a test is made of the upper zone alone, the O-rings should be left off the tube of the orifice-head assembly. The higher pressure of the upper zone acting against the check valve of the lower zone will prevent flow from the lower zone.

6. Take extra precautions to assure accurate measurement of the fluids produced during tests. This is very important and should be stressed with field personnel.

7. For especially severe service, the metal sleeve-type check valve with an O-ring seal is recommended.

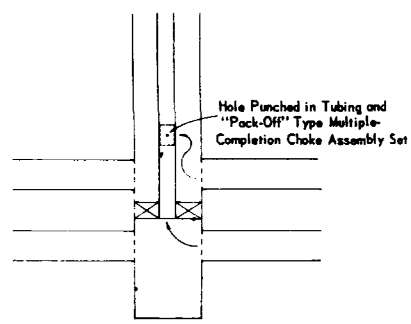

Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

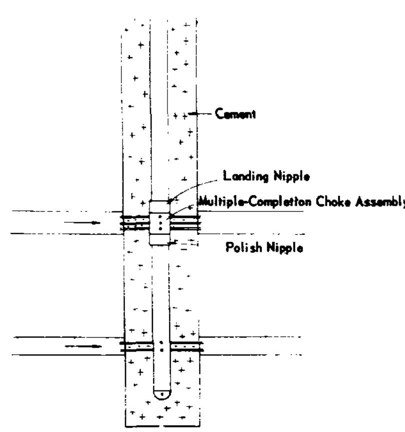

Fig. 10—One-string dual tubingless completion.

Future Development

The future development of the multiple-completion choke assembly and the method of simultaneous production through a single flow string is projected along the following two lines.

1. Surface-recorded bottom-hole pressures will be used to facilitate allocation and packer-leakage tests. A large portion of the wireline work could be eliminated if one had knowledge of the two pressures upstream from the choke and the tubing inlet pressure.

2. Informative material will be presented to state regulatory agencies in an effort to secure general acceptance of the process. This is largely a matter of demonstrating the feasibility of the method, both legally and mechanically, and showing that it will effect conservation and prevent waste.

Conclusions

Simultaneous production of two reservoirs through a single flow string can result in a significant reduction in completion and lifting costs, and will increase current income and ultimate recovery. The multiple-completion choke assembly can be used to maintain separation of the reservoirs and to control the rate of production from each. Test procedures have been developed which provide an acceptable method of determining the contribution from each zone. All requirements imposed by the various regulatory agencies can be satisfied.

References

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