Case No.

3112

Application, Transcripts,

Small Exhibits, Etc.

BEFORE THE OIL CONSERVATION COMMISSION
OF THE STATE OF NEW MEXICO

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
COMMISSION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE No. 3112
Order No. R-2824

APPLICATION OF CONTINENTAL OIL
COMPANY FOR DOWNHOLE COMMINGLING,
RIO ARRIBA COUNTY, NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9 o'clock a.m. on September 30, 1964, at Santa Fe, New Mexico, before Examiner Elvis A. Utz.

NOW, on this 7th day of December, 1964, the Commission, a quorum being present, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That the applicant, Continental Oil Company, seeks authority to install a dual-flow downhole choke assembly in its Jicarilla 28 Well No. 1, located in Unit J of Section 28, Township 25 North, Range 4 West, NMPM, Rio Arriba County, New Mexico, to produce oil from the Gallup formation and to produce oil from the Dakota formation through one string of 2 3/8-inch tubing, with separation of zones by said choke assembly set at approximately 6500 feet and a packer set at approximately 7317 feet.

(3) That the applicant proposes to commingle the Gallup and Dakota production in the 2 3/8-inch tubing above the dual-flow downhole choke assembly and to determine production from each zone by periodic production tests.

(4) That the proposed dual completion should be approved for a six-month period in order to determine the feasibility of authorizing such completions in this area.

(5) That since the Gallup and Dakota formations in the subject well are marginal, the applicant should be authorized to determine production from each zone by periodic production tests witnessed by the Commission.

IT IS THEREFORE ORDERED:

(1) That the applicant, Continental Oil Company, is hereby authorized to install a dual-flow downhole choke assembly in its Jicarilla 28 Well No. 1, located in Unit J of Section 28, Township 25 North, Range 4 West, NMPM, Rio Arriba County, New Mexico, to produce oil from the Gallup formation and to produce oil from the Dakota formation through one string of 2 3/8-inch tubing, with separation of zones by said choke assembly set at approximately 6500 feet and a packer set at approximately 7317 feet;

PROVIDED HOWEVER, that the applicant shall complete, operate, and produce said well in accordance with the provisions of Rule 112-A of the Commission Rules and Regulations insofar as said rule is not inconsistent with this order.

(2) That the applicant shall take a packer-leakage test prior to installation of the downhole choke assembly and upon termination of the six-month test period authorized by this order.

(3) That upon installation of the dual-flow downhole choke assembly and upon termination of the six-month test period authorized by this order, the applicant shall conduct tests to determine packer leakage or seal leakage in the dual-flow downhole choke assembly in either direction, and shall notify the Supervisor, District 3, Oil Conservation Commission, Aztec, New Mexico, of the exact date and time said tests are to commence in order that the Commission may witness the same.

(4) That the applicant is hereby authorized to determine production from each zone of the subject well by periodic production tests and shall notify the Supervisor, District 3, Oil Conservation Commission, Aztec, New Mexico, of the date and time said tests are to commence in order that the Commission may witness the same.

(5) That this case shall be reopened at an examiner hearing in June, 1965, at which time the applicant may appear and show cause why the authority granted under this order should not be terminated.

(6) That jurisdiction of this cause is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

Jack M Campbell

JACK M. CAMPBELL, Chairman

E. S. Walker

E. S. WALKER, Member

A. L. Porter, Jr.

A. L. PORTER, Jr., Member & Secretary

esr/

BEFORE THE OIL CONSERVATION COMMISSION
OF THE STATE OF NEW MEXICO

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
COMMISSION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE No. 3112
Order No. R-2824-A

APPLICATION OF CONTINENTAL OIL
COMPANY FOR DOWNHOLE COMMINGLING,
RIO ARRIBA COUNTY, NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9 o'clock a.m. on July 28, 1965, at Santa Fe, New Mexico, before Examiner Daniel S. Nutter.

NOW, on this 16th day of August, 1965, the Commission, a quorum being present, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That this case has been reopened pursuant to the provisions of Order No. R-2824 to permit the applicant to show cause why the authority granted under Order No. R-2824 should not be terminated.

(3) That the applicant has established that the Gallup and Dakota zones in the subject well are marginal and that it is not economically feasible to equip these zones for conventional operation.

(4) That the applicant has established that continued use of the dual-flow downhole choke assembly in the subject well will permit the recovery of otherwise unrecoverable oil, thereby preventing waste.

(5) That the applicant has established that correlative rights will be protected by allocating production from the subject well to each zone by periodic production tests utilizing the subtraction method.

IT IS THEREFORE ORDERED:

(1) That the authority granted under Order No. R-2824 is hereby continued in full force and effect;

PROVIDED HOWEVER, that a production test shall be conducted annually and production allocated to the Gallup and Dakota zones of the subject well by the subtraction method until further order of the Commission.

(2) That jurisdiction of this cause is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

Jack M Campbell

JACK M. CAMPBELL, Chairman

Guyton B. Hays

GUYTON B. HAYS, Member

A. L. Porter, Jr.

A. L. PORTER, Jr., Member & Secretary

esr/

OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO

Date Aug 3, 1965

CASE NO. 3112 ~~3282~~ HEARING DATE 9 AM July 28, 1965
DSN @ SF

My recommendations for an order in the above numbered case(s) are as follows:

Enter an order authorizing the continued use of a dual-flow downhole choke assembly in Contl Oil Company's Jicarilla 28 well no 1, loc. in Unit J of S 28, T 25N R 4W Rio Arriba Co to produce oil from the Gallup & Dakota formations through one string of 2 3/8 inch tubing, with separation of the zones by said chk assy set @ approximately 6500 ft and a packer set @ approximately 7817 ft.

I find that each of these zones is of low marginal character and that to drill and equip them for conventional operation is not economically feasible further that during the six month test period & using the dual flow downhole choke assembly, ~~results evidence of reliability is~~ sufficient reliability of the test method for attributing production to each zone was obtained in all

to justify this method for low marginal wells of the subject well's nature. Production is to be allocated to the Gallup & Dakota zones of the subject well by the subtraction method whereby the stabilized Dakota production rate will be subtracted from the stabilized Gallup-Dakota rate to obtain the Gallup production. Well shall be tested once a year and further tests may be required.

Staff Member

OIL CONSERVATION COMMISSION
P. O. BOX 2088
SANTA FE, NEW MEXICO 87501

October 3, 1968

Continental Oil Company
200 North Wolcott
Casper, Wyoming 82601

Attention: Mr. W. C. Blackburn

Re: Replacement of Dual-Flow Downhole Choke Assemblies, Rio Arriba County, New Mexico

Gentlemen:

Reference is made to your letter of September 4, 1968, requesting authority to replace the dual-flow downhole choke assemblies installed in certain of your wells in Rio Arriba County, New Mexico, pursuant to authority contained in Commission Orders Nos. R-2824, R-2824-A, and R-2978.

We have carefully reviewed the case files generating the above-named orders, as well as the installations which you now propose to make, and feel that the substitution of the "D" landing nipple with a standing valve and the Camco "MM" mandrel with the Type BG double check valve falls within the intent of the orders in permitting controlled down-hole commingling.

Continental Oil Company is, therefore, hereby authorized to substitute the above equipment in the affected wells for the heretofore authorized Otis and Baker dual-flow choke assemblies.

OIL CONSERVATION COMMISSION
P. O. BOX 2088
SANTA FE, NEW MEXICO 87501

October 3, 1960

Continental Oil Company
200 North Wolcott
Casper, Wyoming

Future applications for administrative approval utilizing the newly authorized equipment will be accepted if filed in accordance with the provisions of Order No. R-2978.

Very truly yours,

A. L. PORTER, Jr.
Secretary-Director

ALP/DSN/esr

cc: United States Geological Survey
Attention: Mr. John Anderson
Drawer 1857
Roswell, New Mexico 88201

United States Geological Survey
Attention: Mr. Phil McGrath
P. O. Box 959
Farmington, New Mexico 87401

Oil Conservation Commission
Attention: Mr. Emery C. Arnold
1000 Rio Brazos Road
Aztec, New Mexico 87410

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OCTOBER 1962

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

J. W. HODGES
MEMBER AIME

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

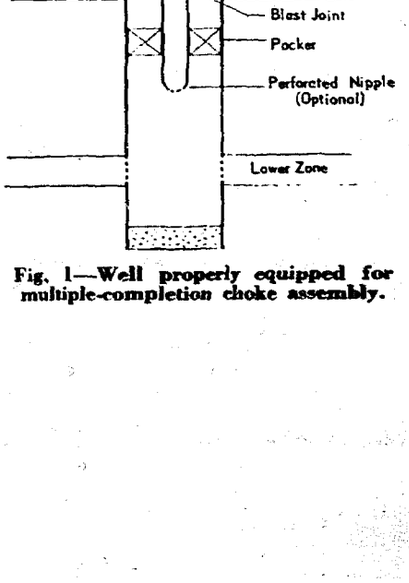


Fig. 1—Well properly equipped for multiple-completion choke assembly.

Original manuscript received in Society of Petroleum Engineers office April 26, 1962. Revised manuscript received Aug. 6, 1962. Paper originally presented at Spring Meeting of the Southern Dist. API Div. of Production held March 1-2, 1962, in Houston, Tex. Also presented at SPE Upper Gulf Coast Drilling and Production Conference held April 5-6, 1962, in Beaumont, Tex.

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 section, 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

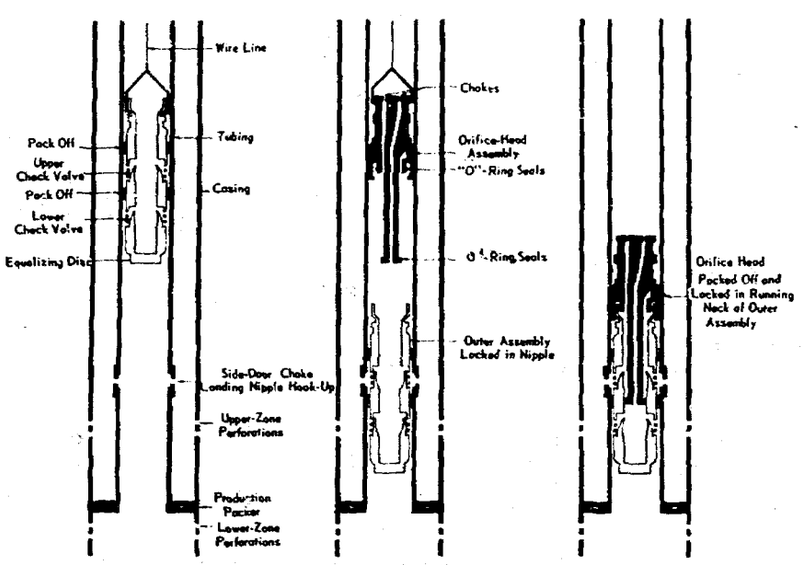


Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

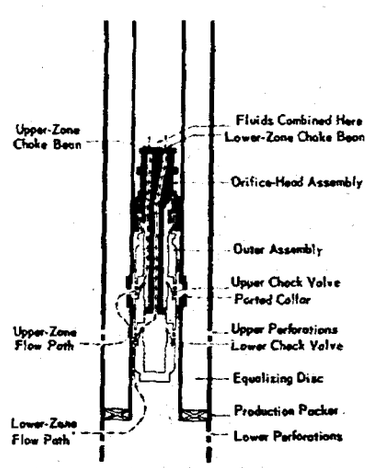


Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

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.	12,958	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

Date	Surface Tubing Pressure (psig)	Measured Production Total Liquid (B/D)	Measured Production Total Gas (Mcf/D)	Calculated Production Upper Zone Oil (B/D)	Calculated Production Upper Zone Gas (Mcf/D)	Calculated Production Lower Zone Condensate (B/D)	Calculated Production Lower Zone Gas (Mcf/D)
6-16-60	900	28.92	498	10.75*	239*	18.17	259
6-17-60	900	30.07	462	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	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

Well No. 1

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

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	922	1,075
127	957	1,200
100	900	1,450

production was gauged at 311 BOPD, a good check with the individual zone tests (157 and 152, a total of 309 BOPD).

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

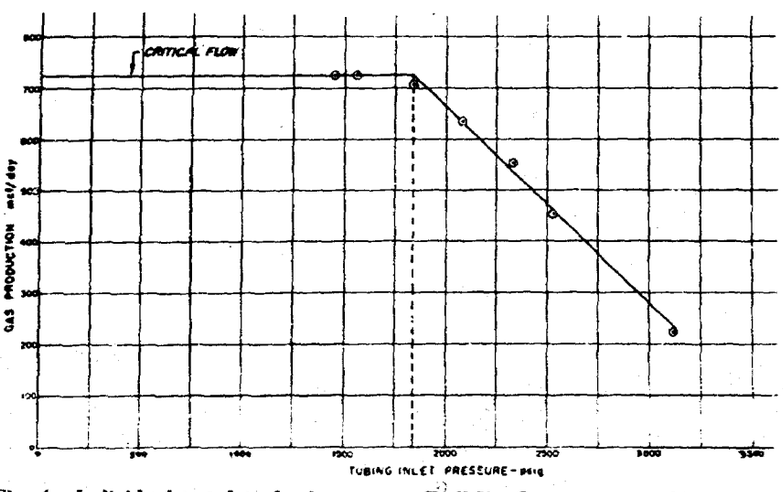


Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

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

Other Applications

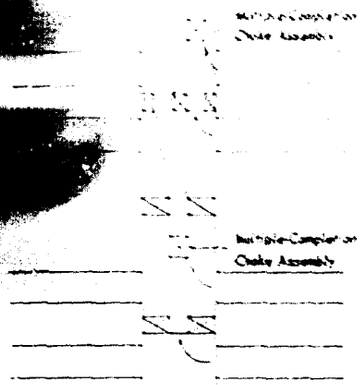


Fig. 5—Two-string quadruple completion.

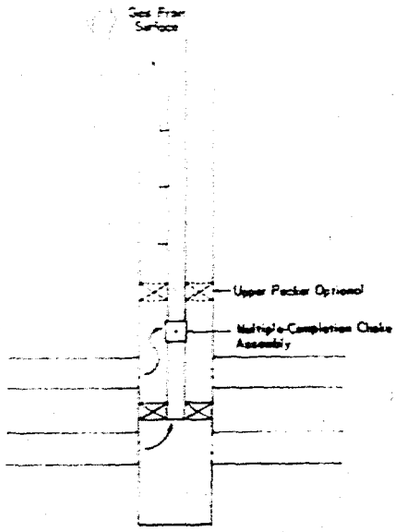


Fig. 6—Gas-lifting two zones with one string of flow valves.

Operational Suggestions

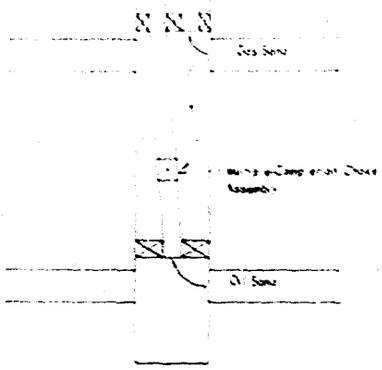


Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

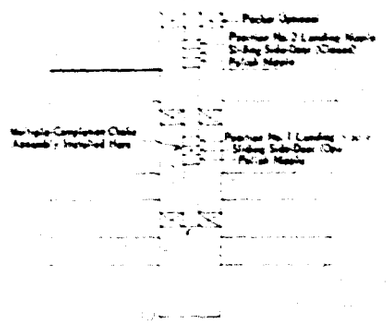


Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

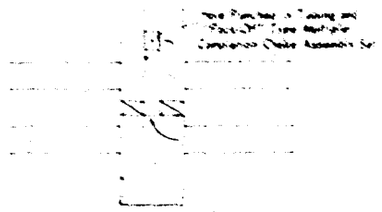


Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

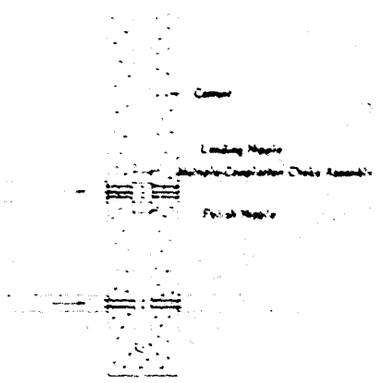


Fig. 10—One-string dual tubingless completion.

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.

References

1. Gilbert, W. E.: "Flowing and Gas-lift Well Performance", *Drill. and Prod. Prac.*, API (1954) 126.
2. Kirkpatrick, C. V.: *The Power of Gas*, Camco, Inc., Houston, Tex. (1953).
3. *Fluid Gradient Curves*, Camco, Inc., Houston, Tex. (1961). ★★★



J. W. HODGES *is an administrative engineer with Sun Oil Co. in Beaumont, Tex. He joined Sun's Gulf Coast Div. in 1938 after graduating from The U. of Texas with a BS degree in petroleum engineering. During his 24 years with Sun he has worked as a roustabout, pumper, roughneck, drilling engineer, production engineer, field superintendent and division petroleum engineer.*

PRESSURE CONTROL · OTIS · SERVICE – EQUIPMENT

OTIS ENGINEERING CORPORATION

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P. O. DRAWER 640
ROSWELL, NEW MEXICO 88201

TELEPHONE 622-4641
AREA CODE 505

August 17, 1966

Miss Ida Rodriguez
Secretary to Director
New Mexico Oil Conservation Commission
P. O. Box 2088
Santa Fe, New Mexico 87501

RE: Transcripts of Hearing
Case No. 3112

Dear Ida:

I return herewith the two transcripts of hearing which you so kindly furnished me.

Thanking you for your courtesy and cooperation in this matter, I remain

Very truly yours,

John F. Russell

JFR:bl

Enclosures

IN REPLY REFER TO:

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

P. O. Drawer 1857
Roswell, New Mexico 88201

RECEIVED
DURANGO PROJ.
SEP 25 1964
OFFICE MGR.
ASST. MGR.
DIST. ENG.
GAS

September 21, 1964

Continental Oil Company
P. O. Box 3312
Durango, Colorado

Attention: Mr. H. D. Haley

Gentlemen:

Your letter of August 11, with attachments, requests approval to commingle oil production from the Gallup and Dakota formations in your well No. 28-1 Jicarilla Apache on Jicarilla tribal Contract No. 66.

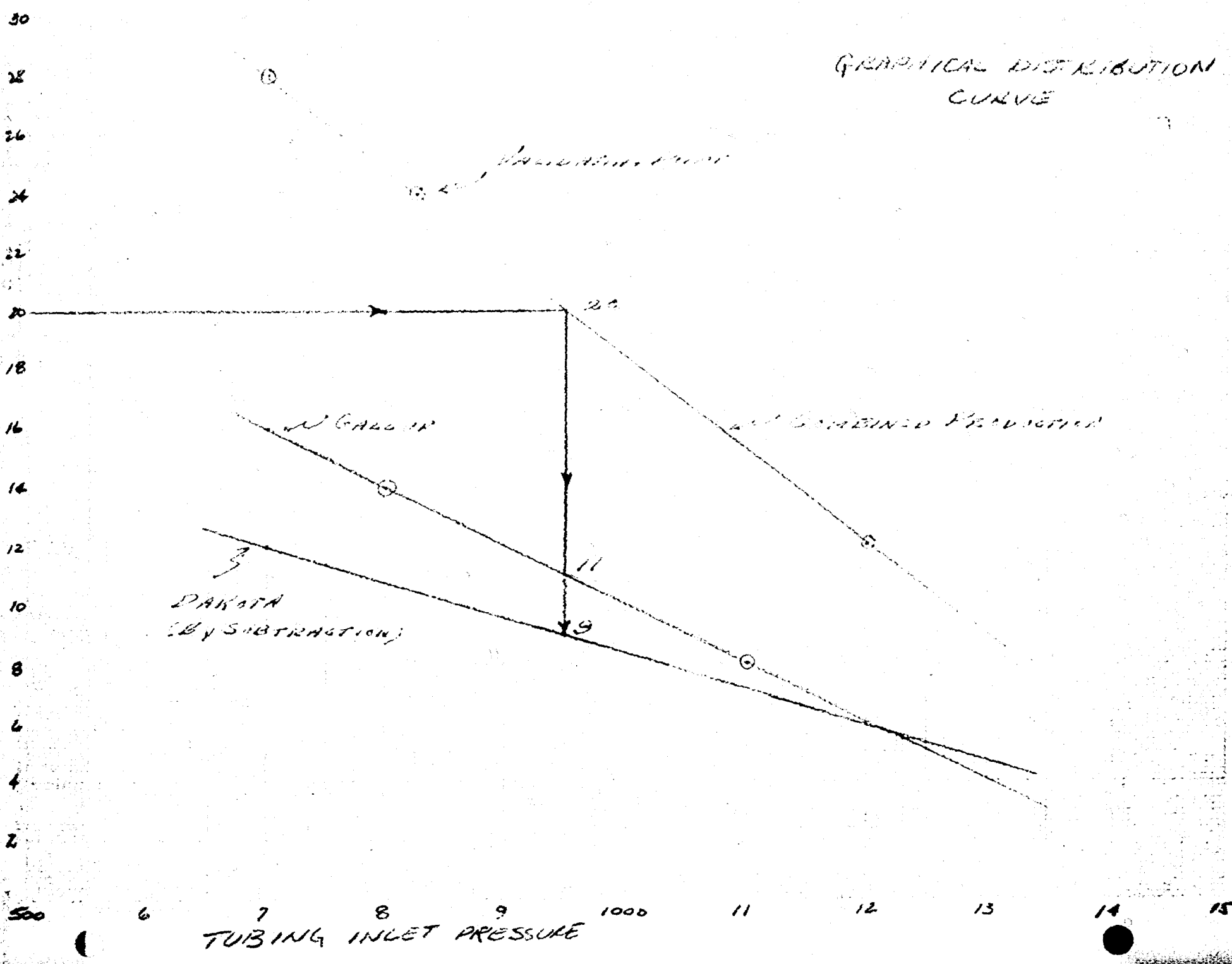
According to the system, as outlined in your proposal, communication between the reservoirs will be accomplished by the use of a downhole separation tool. By additional information submitted in a separate letter on September 8 you state the production from each reservoir will be allocated through the testing of each zone by manually blanking off one zone in the separation tool and producing the other zone. Form 9-361, Lessee's Monthly Report of Sales and Royalty, must show all computations used in the calculation of oil volume for each formation.

The method you propose for the downhole commingling is hereby approved. Any change in the system must be approved by this office.

Sincerely yours,

JOHN A. ANDERSON
Regional Oil & Gas Supervisor

GRAPHICAL DISTRIBUTION CURVE



UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

P. O. Drawer 1857
Roswell, New Mexico 88201

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SEP 25 1964
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JOHN A. ANDERSON
Regional Oil & Gas Supervisor

SUN OIL COMPANY

MILLARD MOOR
MANAGER
FRED E. BUCHANAN
ASSISTANT MANAGER

GULF COAST DIVISION
THE PETROLEUM BUILDING
P.O. BOX 2831
BEAUMONT, TEXAS 77704

'64 OCT 7 PM

October 5, 1964

Mr. Elvis A. Utz
P. O. Box 2088
Santa Fe, New Mexico 87501

Dear Elvis:

I am very appreciative of the time you and Jim Kapteima made available to Billy Hodges and me last Tuesday afternoon for a discussion of the Otis multiple completion choke assembly and our observations of its use.

Billy and I have each been acquainted with Karl Tunstall for the past three years. His experience with the use of this multiple completion tool has been abundant and he is well qualified to discuss and demonstrate the use of the tool.

Neither Billy nor I had met any of the Continental personnel prior to Tuesday, but I was very favorably impressed with the preparation George Brown appeared to have made for the presentation.

Yours very truly,

Joe A. Owens

Joe A. Owens/smh

CONOCO

CONTINENTAL OIL COMPANY

LEGAL DEPARTMENT

'65 AUG 3 AM 10 32

A. T. SMITH
GENERAL ATTORNEY
C. R. HAMPTON
F. E. RADLOFF
G. H. MAYBERRY
C. R. ROBERTS
J. D. TRESNER
ATTORNEYS

1755 GLENARM PLACE
DENVER, COLORADO 80202

August 2, 1965

Mr. D. S. Nutter, Chief Engineer
New Mexico Oil Conservation Commission
P. O. Box 871
Santa Fe, New Mexico

RE: Case 3112, Hearing of July 28, 1965, in regard to Order No. R-2824 authorizing Gallup-Dakota commingling in the wellbore of Jicarilla 28 Well No. 1, Rio Arriba County, New Mexico

Dear Mr. Nutter:

In response to your request at the above captioned hearing, I am providing you the recommendations of Continental Oil Company as stated by Mr. George Brown at the close of direct examination of him by me. The following is the verbatum response of Mr. Brown.

"Initially we request and recommend that Continental Oil Company be permitted here today to continue producing the Jicarilla 28 Well No. 1 with the dualflow choke installed in it until such time as the Commission announces its ruling with respect to the hearing today.

We recommend that the Commission grant Continental Oil Company approval to install such a dualflow choke in the Jicarilla 28 Well No. 1 and to install such a dualflow choke in any existing Gallup-Dakota marginal oil wells located on its acreage in the West Lindrith Field and in any Gallup-Dakota marginal oil wells which may be drilled on its acreage in the West Lindrith Field,

the acreage being shown on Exhibit 1 of the hearing of September 30, 1964 and specifically that:

(1) The Commission make provision for administrative approval of future downhole commingling installations by use of the dualflow choke in existing Gallup-Dakota marginal oil wells and any Gallup-Dakota marginal oil wells which may be drilled within the Continental Oil Company's West Lindrith acreage which consists of four Jicarilla apache leases covering Sections 15 through 22 and 27 through 34, T 25 N, R 4 W, Rio Arriba County, New Mexico;

(2) Application for such administrative approval be filed in triplicate with the Commission and such applications contain detailed data as to gravity, value and volume of the liquid hydrocarbons from each pool, expected gravity and value of the commingled liquid-hydrocarbon production, a schematic diagram of the proposed installation, a plat showing the location of all wells on applicant's lease and the pool from which each well is producing, and whether the actual commercial value of the commingled production will be less than the sum of the values of the production from each common source of supply and if so how much less;

(3) Allocation of production to the Gallup and Dakota zones be by the subtraction method based on annual production tests of the commingled Gallup-Dakota and the Dakota at stabilized production rates;

(4) Continental conduct a packer leakage test and a seal leakage test upon installation of the dualflow choke;

(5) Continental conduct a production test of the commingled Gallup-Dakota and of the Dakota upon installation of the dualflow choke and annually thereafter;

(6) Continental conduct an annual packer leakage test with respect to each well so equipped;

(7) Continental be granted an exception to Rule 303A and any other applicable Rules for the permanent installation of the dualflow choke in the Jicarilla 28 Well No. 1 and in any existing

Gallup-Dakota marginal oil wells or Gallup-Dakota marginal oil wells which may be drilled on Continental Oil Company's West Lindrith acreage, the location of which I have already described."

If we can provide you additional information, please do not hesitate to call on us.

Best Personal Regards,

Charles R. Roberts
Attorney

CRR:kn

cc: Mr. J. M. Durrett, Jr.
Mr. George Brown

DRAFT

JMD/esr
August 9, 1965

BEFORE THE OIL CONSERVATION COMMISSION
OF THE STATE OF NEW MEXICO

CF Subj. _____

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
COMMISSION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE No. 3112

Order No. R-2824-A

APPLICATION OF CONTINENTAL OIL
COMPANY FOR DOWNHOLE COMMINGLING,
RIO ARRIBA COUNTY, NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9 o'clock a.m. on July 28, 1965, at Santa Fe, New Mexico, before Examiner Daniel S. Nutter.

NOW, on this _____ day of August, 1965, the Commission, a quorum being present, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That this case has been reopened pursuant to the provisions of Order No. R-2824 to permit the applicant to show cause why the authority granted under Order No. R-2824 should not be terminated.

(3) That the applicant has established that ~~both~~ the Gallup and Dakota zones in the subject well are marginal and that it is not economically feasible to equip these zones for conventional operation.

(4) That the applicant has established that continued use of the dual-flow downhole choke assembly in the subject well

will permit the recovery of otherwise unrecoverable oil, thereby preventing waste.

(5) That the applicant has established that correlative rights will be protected by allocating production from the subject well to each zone by periodic production tests utilizing the subtraction method.

IT IS THEREFORE ORDERED:

(1) That the authority granted under Order No. R-2824 is hereby continued in full force and effect;

PROVIDED HOWEVER, that a production test shall be conducted annually and production allocated to the Gallup and Dakota zones of the subject well by the subtraction method until further order of the Commission.

(2) That jurisdiction of this cause is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

Case 3112
Heard. 9-30-64
Rec. 11-23-64

BEST AVAILABLE COPY

1. Grant Continental permission to install the "Otis Dual flow downhole choke assembly" on a ~~test~~ 6 mo. test basis.
2. This installation should be allowed only because both zones are marginal oil producing zones.
3. Tests shall be conducted ~~during the test period at the~~ upon installation of the unit and at the conclusion of the test period for the purpose of proving that there is no leakage ~~thru any packer or seal~~ all packers or seals in the unit can hold the required pressure without leakage from either side of the packers or seals.
4. The actual mechanics of the tests shall be approved by the commission before the tests are conducted and the commission shall be given ~~ample time~~ notified of the time of test so that they can be witnessed.
5. Future installations shall not be made until the test is completed.
6. Tests shall also show the feasibility of reporting production of each zone on the basis of periodic production tests.

Encl to Dir.

DRAFT

JMD/esr
Dec. 1, 1964

BEFORE THE OIL CONSERVATION COMMISSION
OF THE STATE OF NEW MEXICO

CF Subj. _____

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
COMMISSION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE No. 3112

Order No. R-282-A

APPLICATION OF CONTINENTAL OIL
COMPANY FOR DOWNHOLE COMMINGLING,
RIO ARRIBA COUNTY, NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9 o'clock a.m. on September 30 1964, at Santa Fe, New Mexico, before Examiner Elvis A. Utz.

NOW, on this _____ day of December, 1964, the Commission, a quorum being present, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That the applicant, Continental Oil Company, seeks authority to install a dual-flow downhole choke assembly in its Jicarilla 28 Well No. 1, located in Unit J of Section 28, Township 25 North, Range 4 West, NMPM, Rio Arriba County, New Mexico, to produce oil from the Gallup formation and to produce oil from the Dakota formation through one string of 2 3/8-inch tubing, with separation of zones by said choke assembly at approximately 6500 feet and a packer set at approximately 7317 ~~7391~~ feet.

(3) That the applicant proposes to commingle the Gallup and Dakota production in the 2 3/8-inch tubing above the dual-flow downhole choke assembly and to determine production from each zone by periodic production tests.

(4) That the proposed dual completion should be approved for a six-month period in order to determine the feasibility of authorizing such completions in this area.

(5) That the Gallup and Dakota formations in the subject area are marginal and the applicant should be authorized to determine production from each zone by periodic production tests witnessed by the Commission.

IT IS THEREFORE ORDERED:

(1) That the applicant, Continental Oil Company, is hereby authorized to install a dual-flow downhole choke assembly in its Jicarilla 28 Well No. 1, located in Unit J of Section 28, Township 25 North, Range 4 West, NMPM, Rio Arriba County, New Mexico, to produce oil from the Gallup formation and to produce oil from the Dakota formation through one string of 2 3/8-inch tubing, with separation of zones by said choke assembly and a packer set at approximately 6500 feet and a packer set at approximately ~~7391~~ 7317 feet;

PROVIDED HOWEVER, that the applicant shall complete, operate, and produce said well in accordance with the provisions of Rule 112-A of the Commission Rules and Regulations insofar as said rule is not inconsistent with this order.

(2) That the applicant shall take a packer-leakage test prior to installation of the downhole choke assembly ~~upon completion~~ and upon termination of the six-month test period authorized by this order.

(3) That upon installation of the dual-flow downhole choke assembly and upon termination of the six-month test period authorized by this order, the applicant shall conduct tests to determine packer leakage or seal leakage ~~packer or seal leakage~~ in the dual-flow downhole choke assembly in either ~~any~~ direction, and shall notify the Supervisor, District 3, Oil Conservation

Commission, Aztec, New Mexico, of the exact date and time said tests are to commence in order that the Commission may witness the same.

(4) That the applicant is hereby authorized to determine production from each zone of the subject well by periodic production tests and shall notify the Supervisor, District 3, Oil Conservation Commission, Aztec, New Mexico, of the date and time said tests are to commence in order that the Commission may witness the same.

(5) That this case shall be reopened at an examiner hearing in June, 1965, at which time the applicant may appear and show cause why the authority granted under this order should not be terminated.

(6) That jurisdiction of this cause is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

GOVERNOR
JACK M. CAMPBELL
CHAIRMAN

State of New Mexico
Oil Conservation Commission

LAND COMMISSIONER
E. S. JOHNNY WALKER
MEMBER

P. O. BOX 871
SANTA FE

STATE GEOLOGIST
A. L. PORTER, JR.
SECRETARY - DIRECTOR

December 7, 1964

DOCKET MAILED
Date 7-15-65

Mr. Jason Kellahin
Kellahin & Fox
Attorneys at Law
Post Office Box 1769
Santa Fe, New Mexico

DOCKET MAILED
Date 6-16-65

DOCKET MAILED
Date 5-27-65

Re: Case No. 3112 and 3156
Order No. R-2824 and R-2825
Applicant:
Continental Oil Company

Dear Sir:

Enclosed herewith are two copies of the above-referenced Commission order recently entered in the subject case.

Very truly yours,

A. L. Porter, Jr.

A. L. PORTER, Jr.
Secretary-Director

ir/

Carbon copy of order also sent to:

Hobbs OCC x
Artesia OCC
Aztec OCC x (R-2824)

DOCKET MAILED
Date 5-27-65

DOCKET MAILED
Date 6-16-65

OTHER R-2824 sent to Charles Roberts - Continental Oil Co., ~~Durango, Colo~~ Denver, Colo

GOVERNOR
JACK M. CAMPBELL
CHAIRMAN

State of New Mexico
Oil Conservation Commission

LAND COMMISSIONER
GUYTON B. HAYS
MEMBER

STATE GEOLOGIST
A. L. PORTER, JR.
SECRETARY - DIRECTOR

P. O. BOX 2088
SANTA FE

August 16, 1965

Re: Case No. 3112 & 3282 & 3281
Order No. R-2824-A, R-2947 & R-2949
Applicant: Continental & Samuel Dunn

Mr. Jason Kellahin
Kellahin & Fox
Attorneys at Law
Post Office Box 1769
Santa Fe, New Mexico

Dear Sir:

Enclosed herewith are two copies of the above-referenced Commission order recently entered in the subject case.

Very truly yours,

A. L. Porter, Jr.
A. L. PORTER, Jr.
Secretary-Director

ir/

Carbon copy of order also sent to:

Hobbs OCC x
Artesia OCC
Aztec OCC x
OTHER

OIL CONSERVATION COMMISSION
P. O. BOX 871
SANTA FE, NEW MEXICO

LEGAL DIVISION
PHONE 827-2741

August 20, 1965

COPY

Mr. Charles R. Roberts
Attorney
Continental Oil Company
1755 Clenarm Place
Denver, Colorado 80202

Re: Case No. 3112
Order No. R-2824-A

Dear Charlie:

This letter will confirm our recent telephone conversation concerning the above case and order.

The Commission felt that an order could not be entered in this case establishing an administrative procedure to authorize use of the dual-flow downhole choke in additional wells as the case was advertised only for the Jicarilla Well No. 28 and our jurisdiction to enter such an order would therefore be questionable. Although it will be necessary to docket and advertise another case to consider the establishment of such an administrative procedure, it should not be necessary to present additional evidence. The testimony presented in Case No. 3112 thoroughly covered your proposed administrative procedure and could be incorporated into the record by motion.

In order to create a complete record in the new case, I suggest you file a formal application requesting establishment of the administrative procedure and describing the area in which you propose the procedure would be applicable. As we discussed,

OIL CONSERVATION COMMISSION
P. O. BOX 871
SANTA FE, NEW MEXICO

August 20, 1965

Mr. Charles R. Roberts
Attorney
Continental Oil Company
1755 Glenarm Place
Denver, Colorado 80202

COPY

I feel that the administrative procedure would have to be applicable to all operators within a given area.

I am enclosing an additional copy of Order No. R-2824-A. Please contact me if we can be of further assistance.

Best personal regards.

Very truly yours,

J. M. DURRETT, Jr.
Attorney

JMD/esr
Enclosure

'65 AUG 3

August 2, 1965

Mr. D. S. Nutter, Chief Engineer
New Mexico Oil Conservation Commission
P. O. Box 871
Santa Fe, New Mexico

RE: Case 3112, Hearing of July 28, 1965, in regard to Order No. R-2824 authorizing Gallup-Dakota commingling in the wellbore of Jicarilla 28 Well No. 1, Rio Arriba County, New Mexico

Dear Mr. Nutter:

In response to your request at the above captioned hearing, I am providing you the recommendations of Continental Oil Company as stated by Mr. George Brown at the close of direct examination of him by me. The following is the verbatum response of Mr. Brown.

" Initially we request and recommend that Continental Oil Company be permitted here today to continue producing the Jicarilla 28 Well No. 1 with the dualflow choke installed in it until such time as the Commission announces its ruling with respect to the hearing today.

We recommend that the Commission grant Continental Oil Company approval to install such a dualflow choke in the Jicarilla 28 Well No. 1 and to install such a dualflow choke in any existing Gallup-Dakota marginal oil wells located on its acreage in the West Lindrith Field and in any Gallup-Dakota marginal oil wells which may be drilled on its acreage in the West Lindrith Field,

the acreage being shown on Exhibit 1 of the hearing of September 30, 1964 and specifically that:

(1) The Commission make provision for administrative approval of future downhole commingling installations by use of the dualflow choke in existing Gallup-Dakota marginal oil wells and any Gallup-Dakota marginal oil wells which may be drilled within the Continental Oil Company's West Lindrith acreage which consists of four Jicarilla apache leases covering Sections 15 through 22 and 27 through 34, T 25 N, R 4 W, Rio Arriba County, New Mexico;

(2) Application for such administrative approval be filed in triplicate with the Commission and such applications contain detailed data as to gravity, value and volume of the liquid hydrocarbons from each pool, expected gravity and value of the commingled liquid-hydrocarbon production, a schematic diagram of the proposed installation, a plat showing the location of all wells on applicant's lease and the pool from which each well is producing, and whether the actual commercial value of the commingled production will be less than the sum of the values of the production from each common source of supply and if so how much less;

(3) Allocation of production to the Gallup and Dakota zones be by the subtraction method based on annual production tests of the commingled Gallup-Dakota and the Dakota at stabilized production rates;

(4) Continental conduct a packer leakage test and a seal leakage test upon installation of the dualflow choke;

(5) Continental conduct a production test of the commingled Gallup-Dakota and of the Dakota upon installation of the dualflow choke and annually thereafter;

(6) Continental conduct an annual packer leakage test with respect to each well so equipped;

(7) Continental be granted an exception to Rule 303A and any other applicable Rules for the permanent installation of the dualflow choke in the Jicarilla 28 Well No. 1 and in any existing

Gallup-Dakota marginal oil wells or Gallup-Dakota marginal oil wells which may be drilled on Continental Oil Company's West Lindrith acreage, the location of which I have already described."

If we can provide you additional information, please do not hesitate to call on us.

Best Personal Regards,

Charles R. Roberts
Attorney

CRR:kn

cc: Mr. J. M. Durrett, Jr.
Mr. George Brown

CONOCO

CONTINENTAL OIL COMPANY

P. O. Box 3312
Durango, Colorado
August 11, 1964

New Mexico Oil Conservation Commission (3)
P. O. Box 2088
Santa Fe, New Mexico

Attention: Mr. A. L. Porter - Secretary Director

Gentlemen:

A hearing before the New Mexico Oil Conservation Commission is requested for the purpose of presenting application by Continental Oil Company to install a downhole commingling tool on a test basis in an existing Gallup-Dakota dual-oil completion well. The test well is Jicarilla 28 Well No. 1, located in Unit J, Section 28, T25N, R4W, Rio Arriba County, New Mexico.

The two sources of supply are commonly owned and the proposed downhole installation is intended to prevent communication between the two reservoirs at all times. Application on a one-well test basis is proposed so that data and procedures for such tests as packer leakage and communication tests and production allocation tests can be established. The commingling installation will be observed to determine the effectiveness of the installation.

The primary purpose of the installation and testing is to establish a method whereby further development of the 16-section West Lindrith block in T25N, R4W, can be economically justified. Past producing histories indicate that further development cannot be economically justified by conventional single and dual completion methods and present producing methods.

The following data and exhibits are attached for preliminary information:

1. Lease plat showing wells on the lease and pools from which each are producing.

2. Data requirements for surface commingling installations.

3. Log of Jicarilla 28 Well No. 1, showing formation tops and location of present retainer production packer and perforations in the Gallup and Dakota formation.

4. Schematic diagram of Otis Engineering Corporation's "Dual Flow Choke Assembly" downhole commingling tool.

5. Schematic diagram showing present and proposed installations in Jicarilla 28 Well No. 1.

6. Composite Performance Curve for a typical Jicarilla Gallup and Dakota well.

If additional information is required, please advise.

Very truly yours,

H. D. Haley
District Manager
Durango District
Production Department

CAB/ca

cc: Mr. E. A. Austin, Continental Oil Company, Denver, Colorado (2)
U. S. Geological Survey, Roswell, New Mexico (1)

DATA [illegible] FOR SURFACE COMMINGLING [illegible]

Average Daily Oil Production for 90-Day Period:

Jicarilla 28 Well No. 1	Gallup	Dakota
May	13 BOPD	3 BOPD
June	13 BOPD	5 BOPD
July	10 BOPD	8 BOPD

Top Unit Allowable: Gallup - 124 BOPD
Dakota - 164 BOPD
Crude Purchaser: Llaves Pipeline Ltd. - Farmington, New Mexico
Royalty Interest Owner: Jicarilla Apache Tribe
Liquid Hydrocarbon Gravities: Gallup - 46.4° API
Dakota - 48.4° API
Commingled Liquid Hydrocarbon Gravity - 46° API
Commingled gravity on adjacent lease (Jicarilla 22) over a six-month period has averaged 45.3° API.

Value of 46.4° API Crude = $2.35 per barrel
Value of 48.4° API Crude = $2.35 per barrel less $.08 = $2.27
Value of 46° API Crude = $2.35 per barrel less $.02 = $2.33

Anticipated Producing Rates: Gallup - 14 BOPD
Dakota - 8 BOPD

Value Calculations: Gallup 14 BOPD x $2.35 = $32.90
Dakota 8 BOPD x $2.27 = 18.16
Total Separate Value = $50.06/Day
Commingled Value - 22 BOPD x $2.33 = $51.26/Day

The value of the commingled production will not be less than the value of the production from each common source of supply.

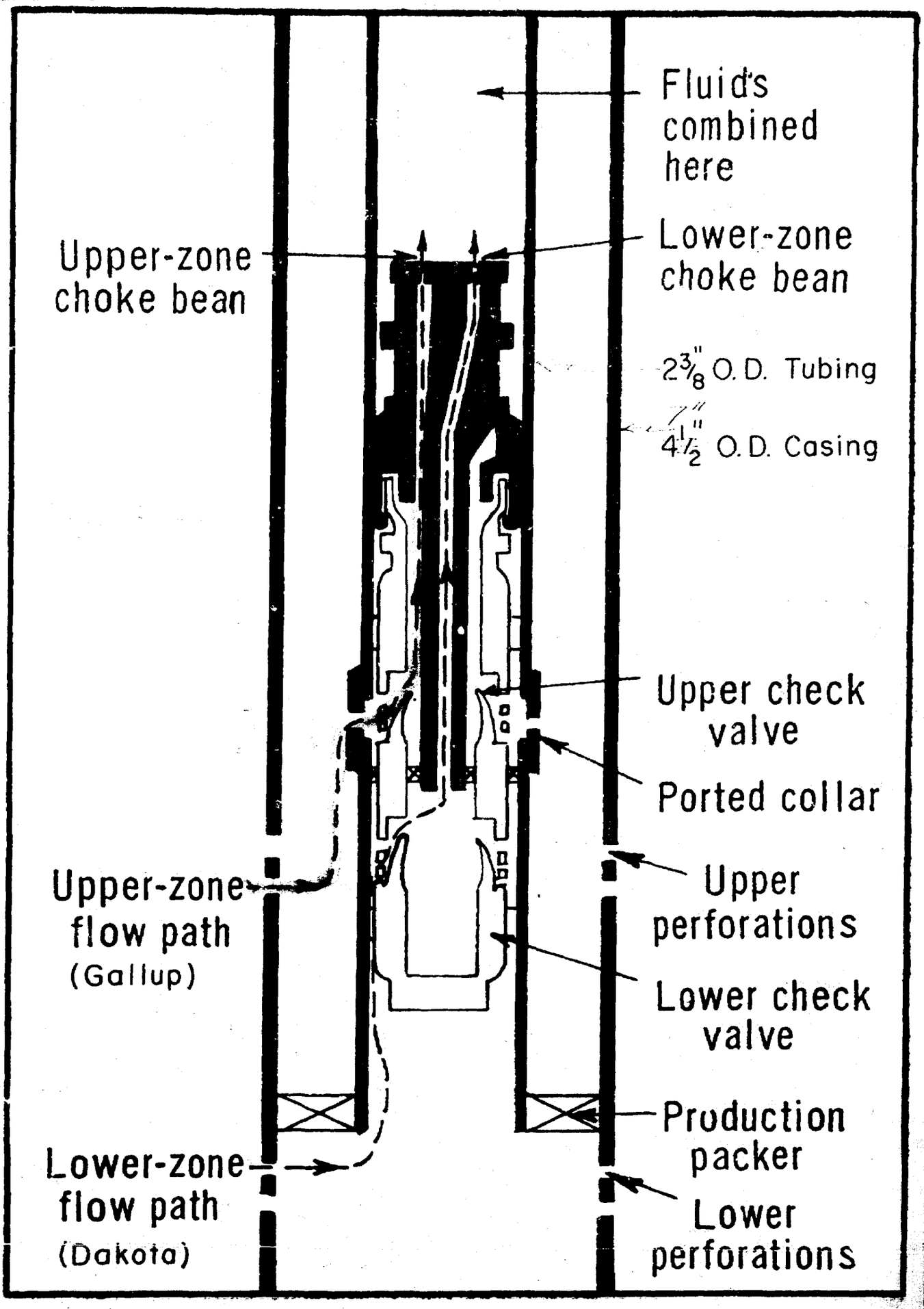
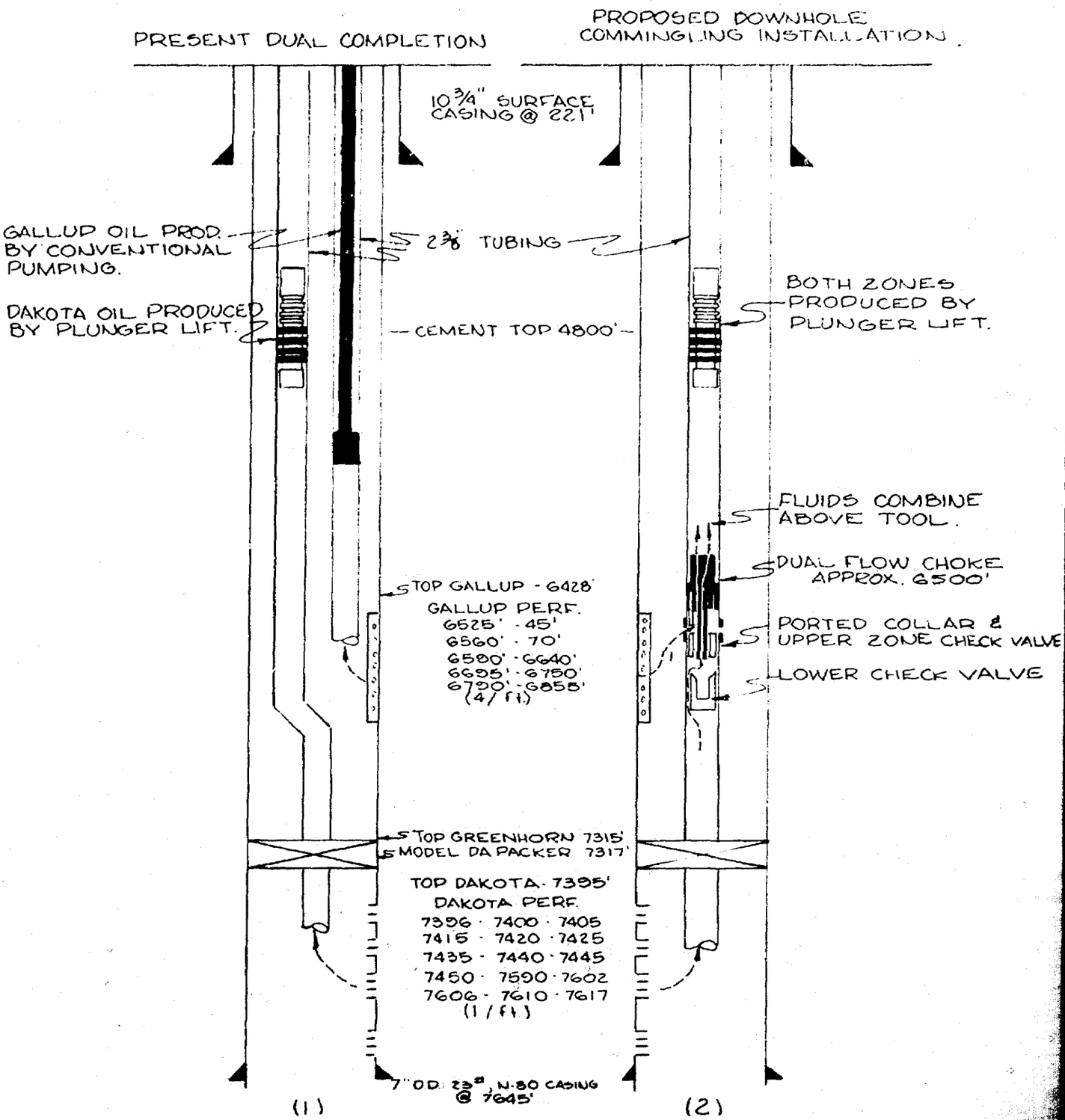


FIGURE NO. 7

Schematic diagram showing installation of Otis "Dual flow choke assembly" for dual zone downhole commingling.

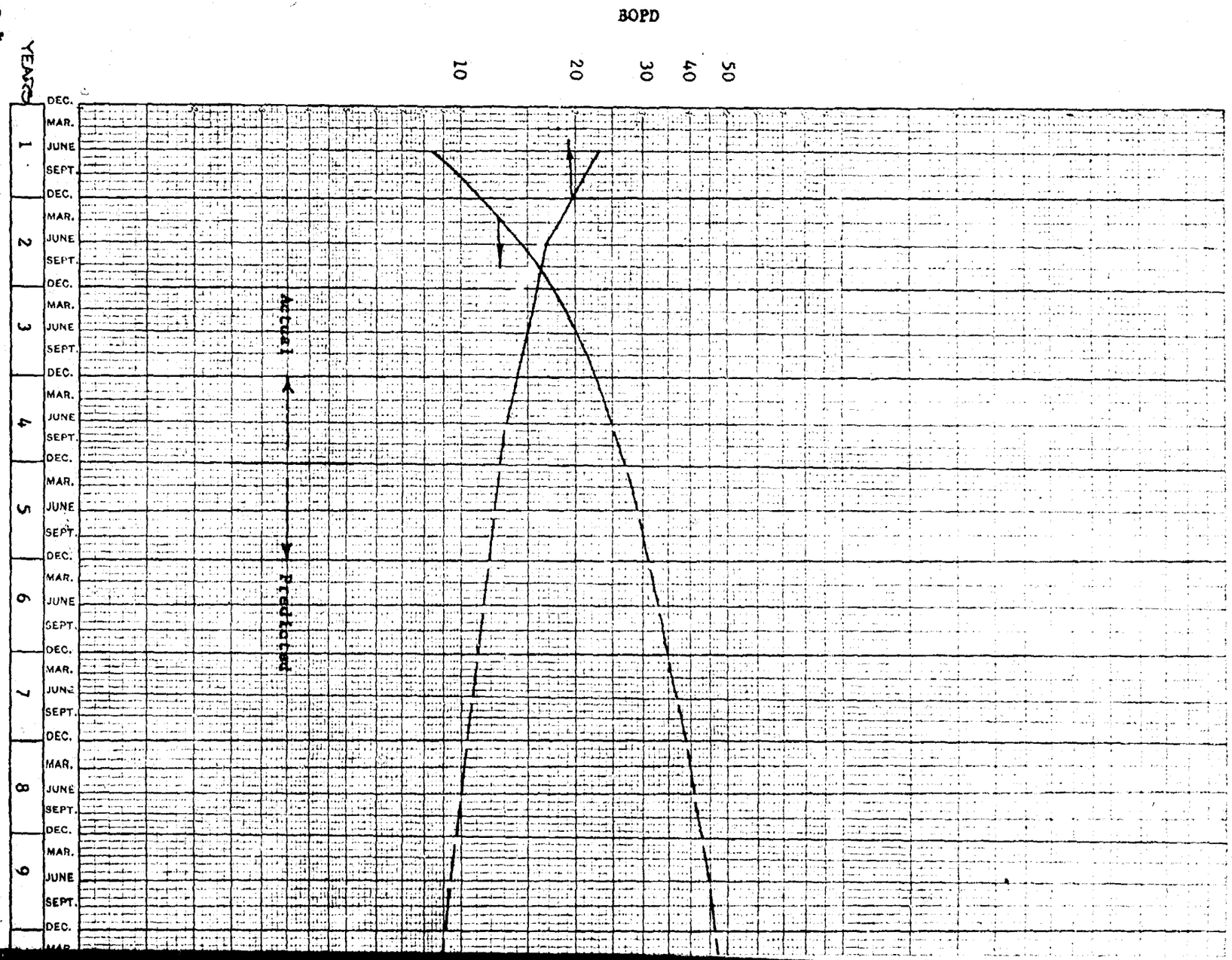


JICARILLA 28 WELL No. 1

SCHEMATIC DIAGRAM SHOWING PRESENT CONVENTIONAL DUAL GALLUP DAKOTA COMPLETION(1) AND PROPOSED INSTALLATION OF "DUAL FLOW CHOKE ASSEMBLY" DUAL ZONE DOWNHOLE COMMINGLING(2).

NO. 4172. TWENTY YEARS BY MONTHS X 3 3-INCH CYCLES RATIO RULING.

CODEX BOOK COMPANY, INC. NORWOOD, MASSACHUSETTS

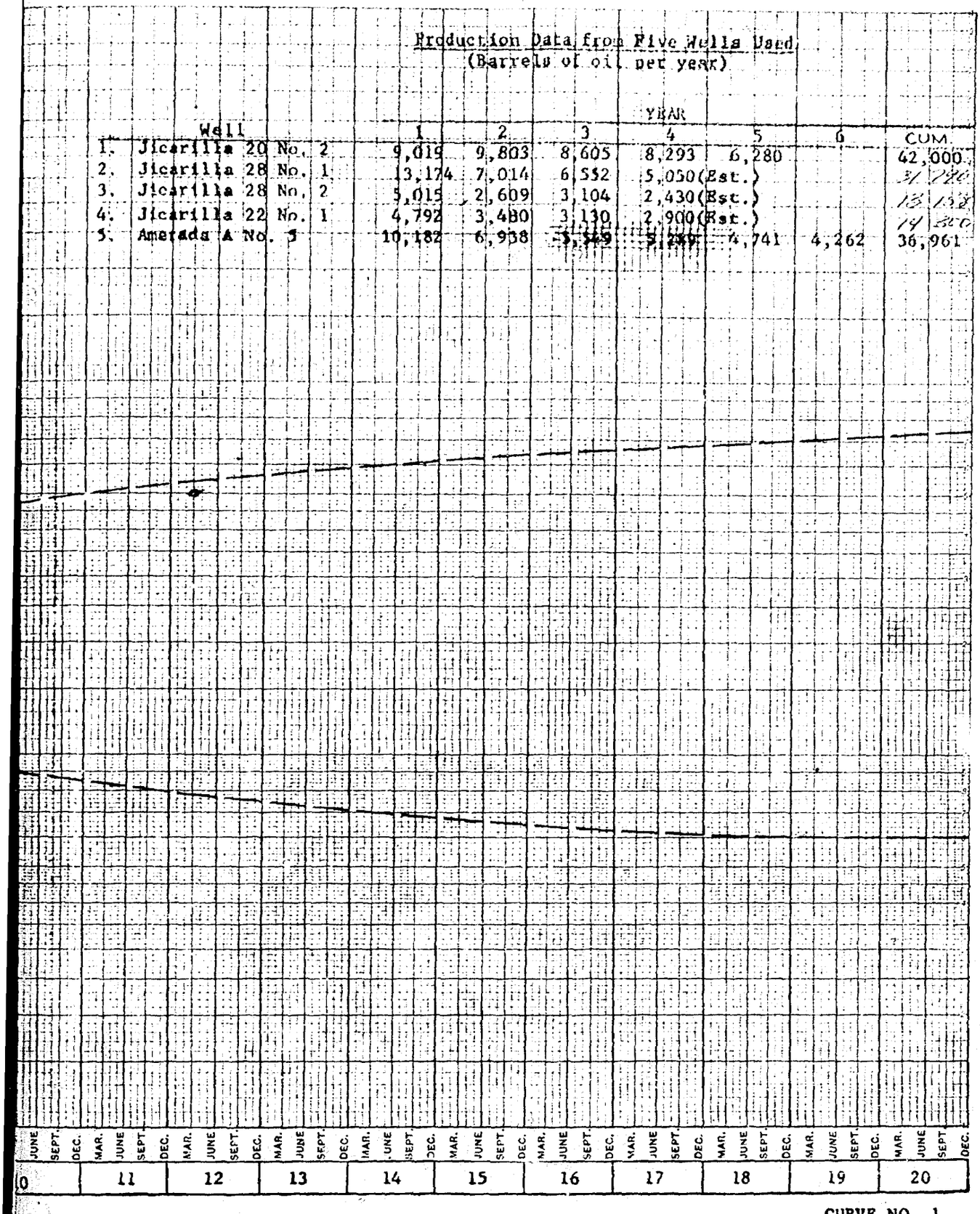


COMPOSITE - TYPICAL WEST LINDRITH GALLUP WELL

Rio Arriba County, New Mexico

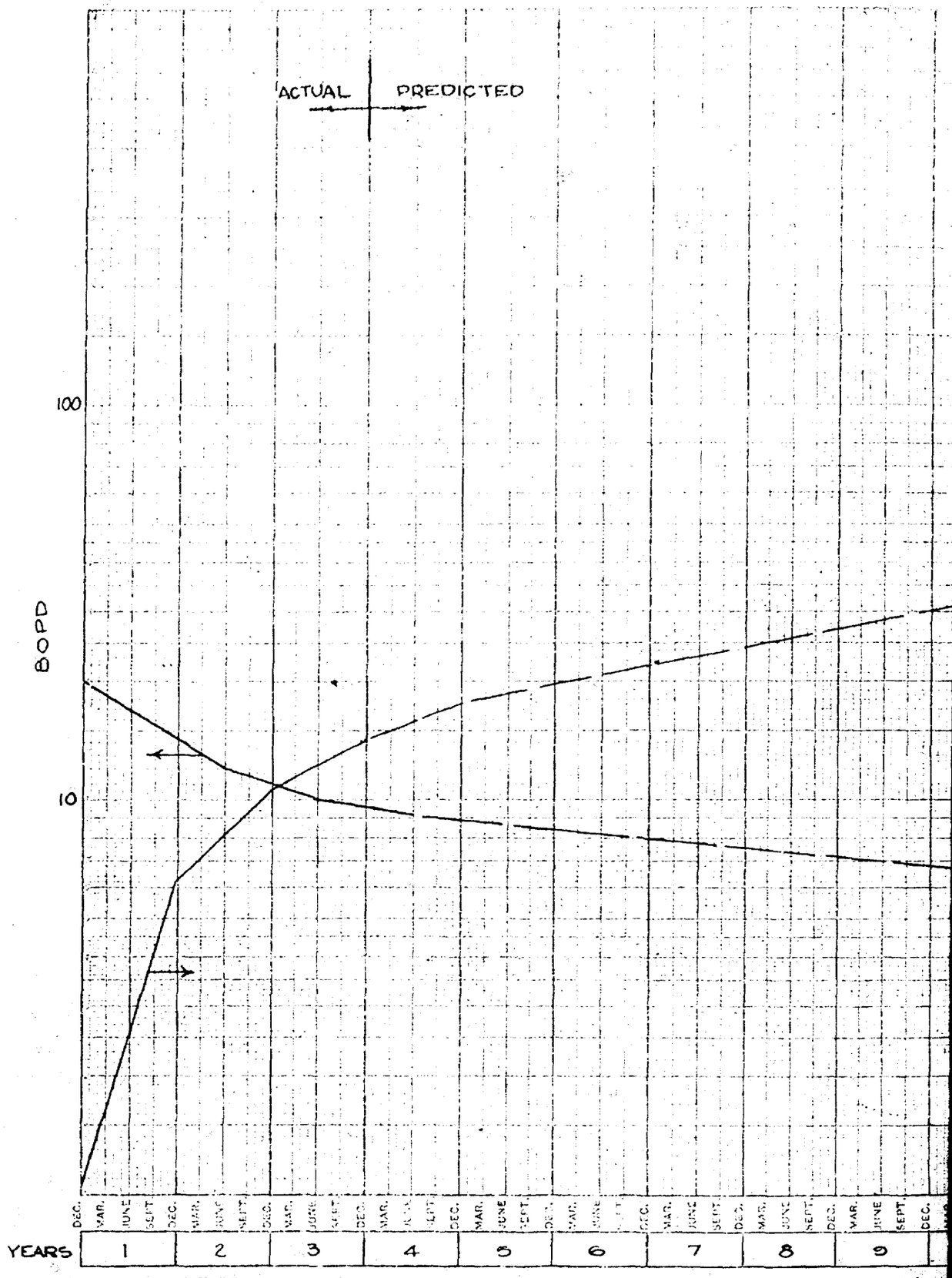
Production Data from Five Wells Used
(Barrels of oil per year)

Well	YEAR 1	2	3	4	5	6	CUM
1. Jicarilla 20 No. 2	9,019	9,803	8,605	8,293	6,280		42,000
2. Jicarilla 28 No. 1	13,174	7,014	6,552	5,050(Est.)			31,790
3. Jicarilla 28 No. 2	5,015	2,609	3,104	2,430(Est.)			13,158
4. Jicarilla 22 No. 1	4,792	3,480	3,130	2,900(Est.)			14,300
5. Amerada A No. 3	10,182	6,938	3,349	3,289	4,741	4,262	36,961



CURVE NO. 1

CODEX BOOK COMPANY, INC. NORWOOD, MASS. U.S.A.

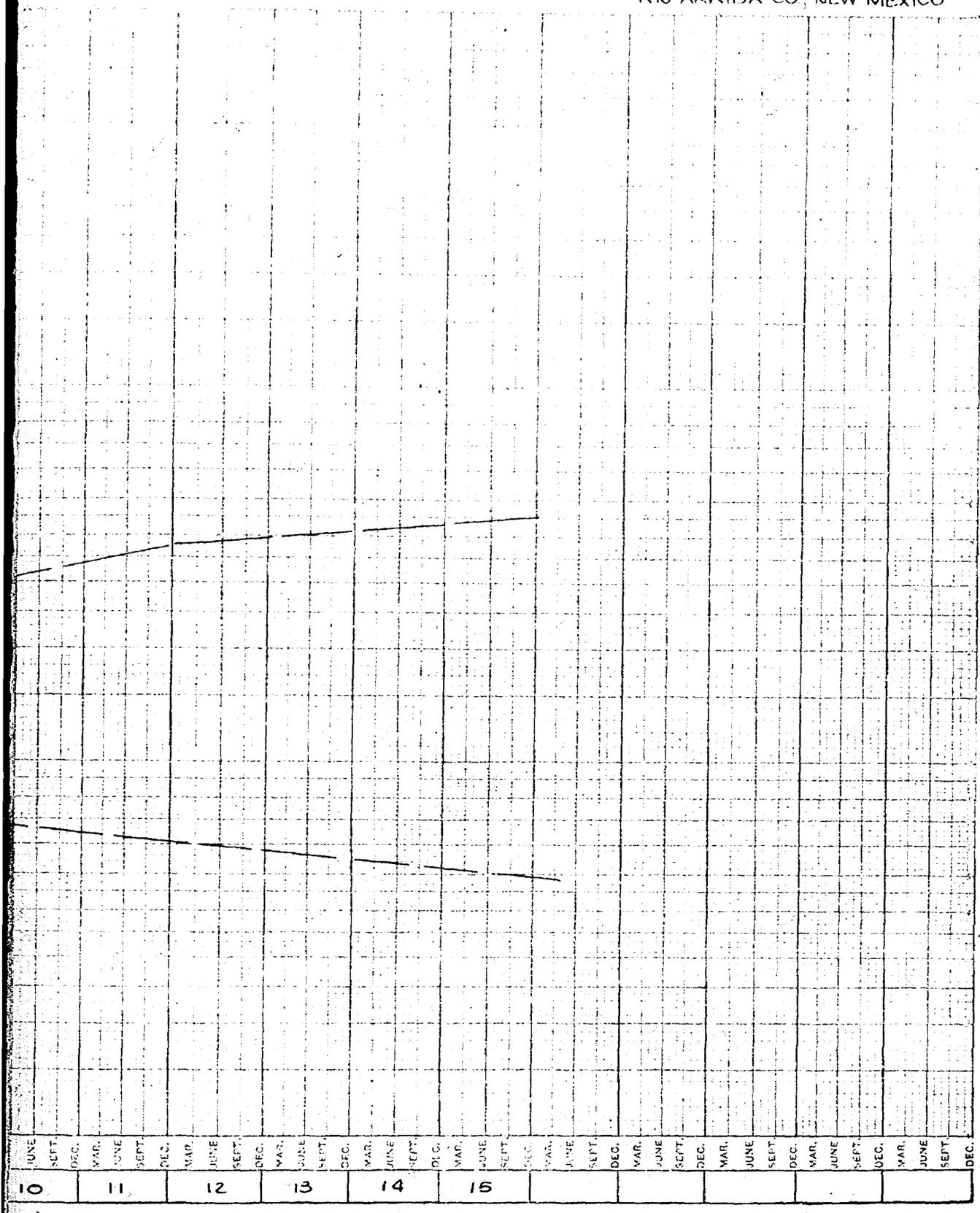


NO. 4172. TWENTY YEARS BY MONTHS X 3 INCH CYCLES RATIO RULING.

WEST LINDRITH DAKOTA

TYPICAL WELL

RIO ARRIBA CO, NEW MEXICO



Curve No. 2

R-4-W

T 25 N

18 17 16 15

19 20 21 22

Jicarilla 20 Lease

Jicarilla 22 Lease

30 29 28 27

Amerada A-5

31 32 33 34

Jicarilla 30 Lease

Jicarilla 28 Lease

Northwest 16-2

Johnston 1-1

Johnston 3-9

Northwest 15-11

LEGEND

- GALLUP OIL WELL
- DAKOTA - GALLUP DUAL COMPLETION

CONTINENTAL OIL COMPANY

PRODUCTION DEPARTMENT

DRAWN	SCALE 1" = 4000'	FILE NO.
CHECKED	DATE	
APPROVED	SHEET ____ OF ____	

WEST LINDRITH BLOCK
Rio Arriba Co., New Mexico

SHELL OIL COMPANY
SHELL BUILDING
P O BOX 2099
HOUSTON, TEXAS 77001

RECEIVED
AUG 27 1964
OIL CON. COM.
DIST. 3

August 25, 1964

Subject: Jicarilla Apache 28 Well No. 1
Sec. 28, T-25-N, R-4-W
Rio Arriba County, New Mexico

Continental Oil Company
P. O. Box 3312
Durango, Colorado

Attention Mr. H. D. Haley

Gentlemen:

In response to your letters of August 14, 1964, and August 21, 1964, and based on the facts set out therein, this is to advise that Shell Oil Company, as purchaser of the crude oil production, does not object to commingling the Gallup and Dakota production from the subject well.

Please advise us of the effective date of such commingling.

Yours very truly,

B. G. Crocker
Crude Oil Representative

DKB:SMP

DATA REQUIRED FOR SURFACE COMMINGLING APPLICATIONS

Average Daily Oil Production for 90-day Period:

Jicarilla 28 Well No. 1	Gallup	Dakota
May	13 BOPD	8 BOPD
June	12 BOPD	5 BOPD
July	10 BOPD	8 BOPD

Top Unit Allowable: Gallup - 124 BOPD
Dakota - 164 BOPD

Crude Purchaser: Llavas Pipeline Ltd. - Farmington, New Mexico

Royalty Interest Owner: Jicarilla Apache Tribe

Liquid Hydrocarbon Gravities: Gallup - 44.4° API
Dakota - 48.4° API

Commingled Liquid Hydrocarbon Gravity - 46° API

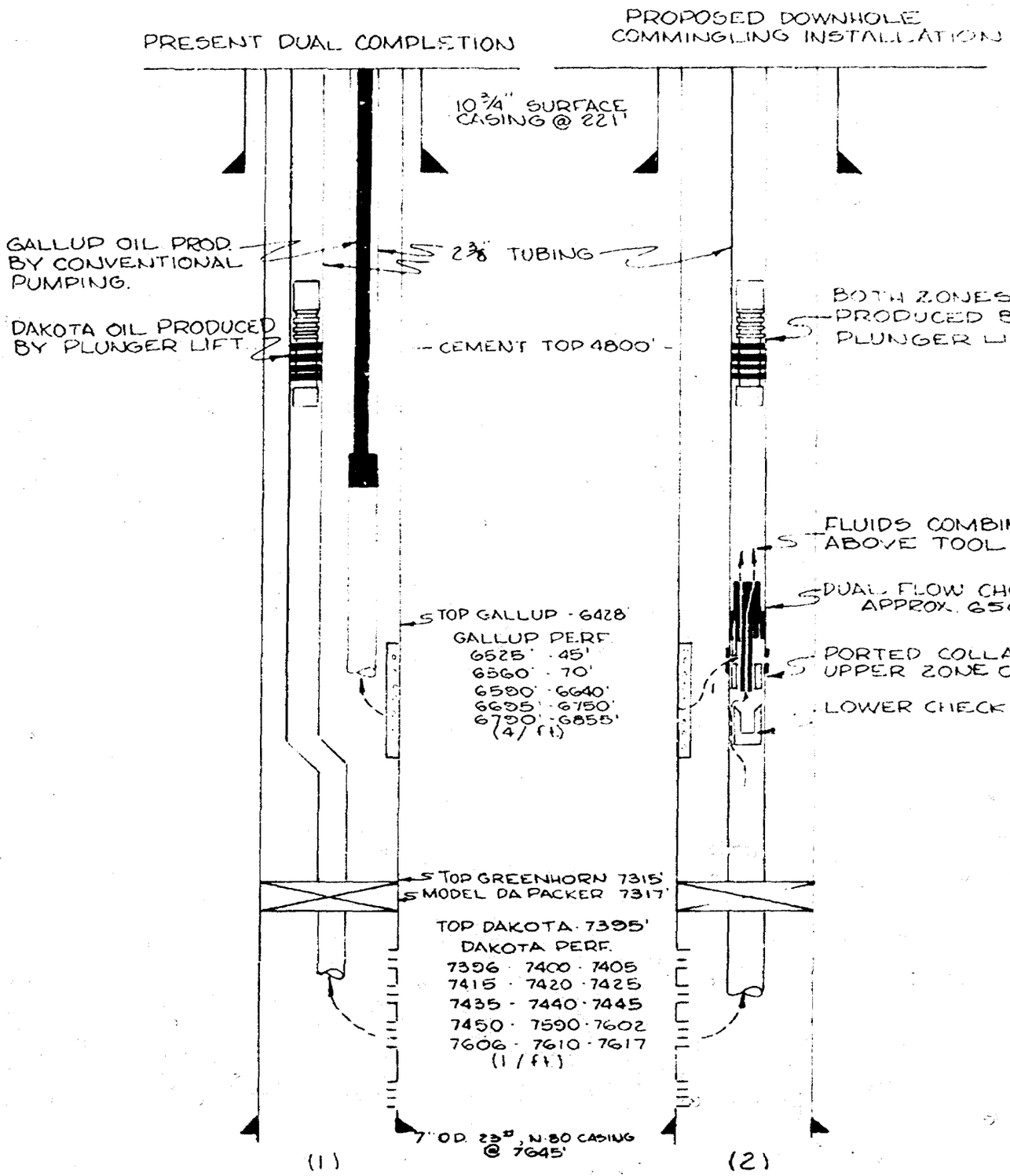
Commingled gravity on adjacent lease (Jicarilla 22) over a six-month period has averaged 45.3° API.

Value of 44.4° API Crude = $2.35 per barrel
Value of 48.4° API Crude = $2.35 per barrel less $.08 = $2.27
Value of 46° API Crude = $2.35 per barrel less $.02 = $2.33

Anticipated Producing Rates: Gallup - 14 BOPD
Dakota - 8 BOPD

Value Calculations: Gallup 14 BOPD x $2.35 = $32.90
Dakota 8 BOPD x $2.27 = 18.16
Total Separate Value = $50.06/Day
Commingled Value - 22 BOPD x $2.33 = $51.26/Day

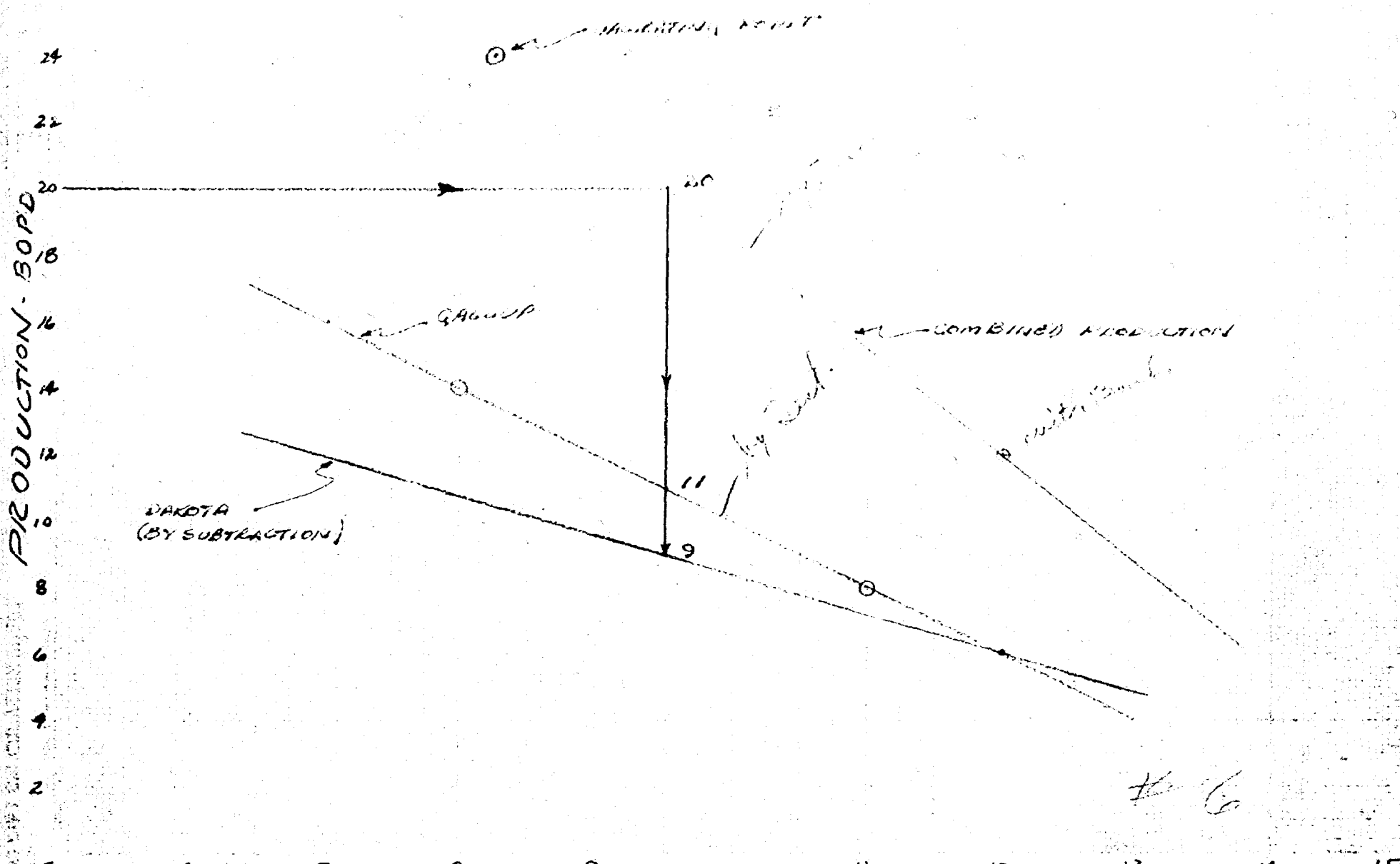
The value of the commingled production will not be less than the value of the production from each common source of supply.



JICARILLA 28 WELL No. 1

SCHEMATIC DIAGRAM SHOWING PRESENT CONVENTIONAL DUAL GALLUP DAKOTA COMPLETION(1) AND PROPOSED INSTALLATION OF "DUAL FLOW CHOKE ASSEMBLY" DUAL ZONE DOWNHOLE COMMINGLING(2).

GRAPHICAL DISTRIBUTION CURVE



#6

SHELL OIL COMPANY
SHELL BUILDING
P O BOX 2099
HOUSTON, TEXAS 77001

RECEIVED
AUG 27 1964
OFFICE MGR. 1 B
DIF
DIST. ENG.

August 25, 1964

Subject: Jicarilla Apache 28 Well No. 1
Sec. 28, T-25-N, R-4-W
Rio Arriba County, New Mexico

Continental Oil Company
P. O. Box 3312
Durango, Colorado

Attention Mr. H. D. Haley

Gentlemen:

In response to your letters of August 14, 1964, and August 21, 1964, and based on the facts set out therein, this is to advise that Shell Oil Company, as purchaser of the crude oil production, does not object to commingling the Gallup and Dakota production from the subject well.

Please advise us of the effective date of such commingling.

Yours very truly,

B. G. Crocker

B. G. Crocker
Crude Oil Representative

DKB:SMP

REPRINTED FROM
WORLD OIL
OCTOBER 1961

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

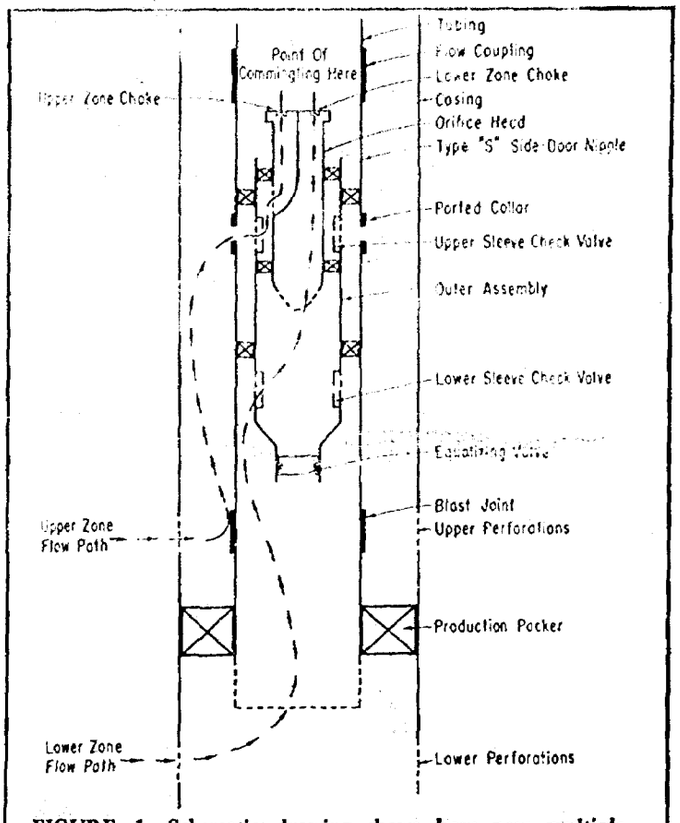


FIGURE 1—Schematic drawing shows how new multiple completion wireline tool works. Note that production is effectively separated until commingled above chokes.

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

OTIS ENGINEERING CORPORATION

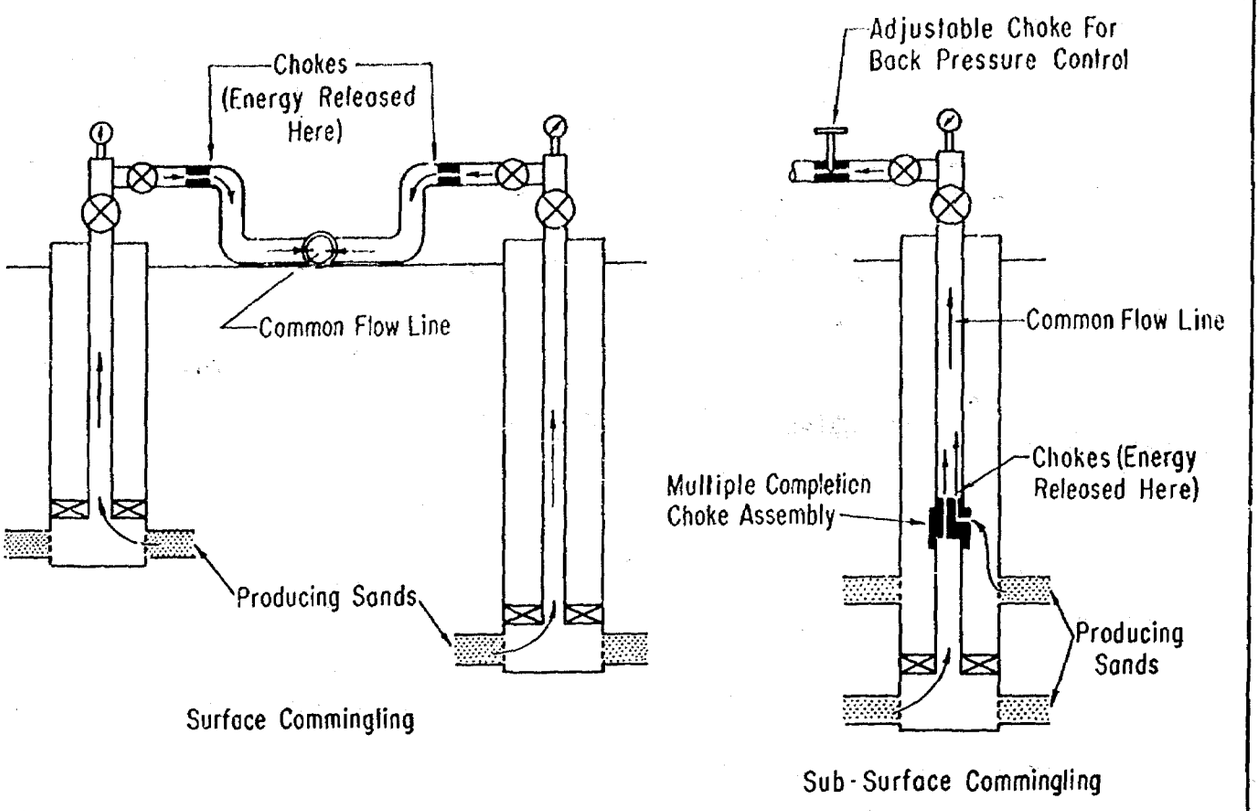


FIGURE 2—Downhole commingling is analoguous to surface commingling except that the pressure reduction is accomplished at the bottom of the hole where energy in released gas can be used.

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.

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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.

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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*.

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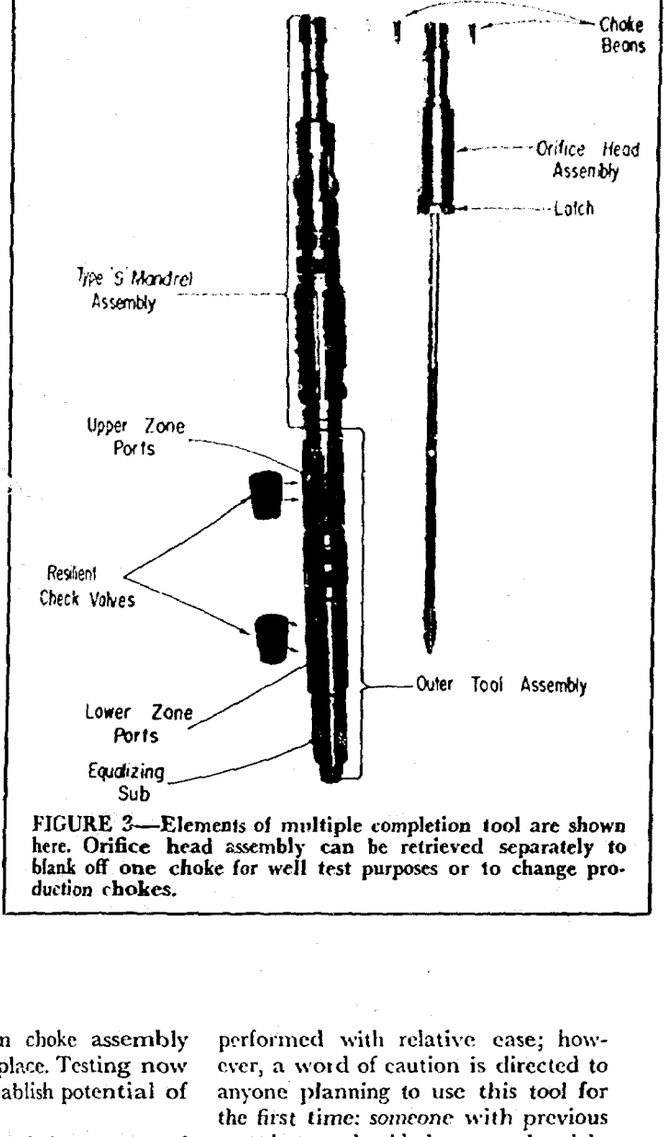


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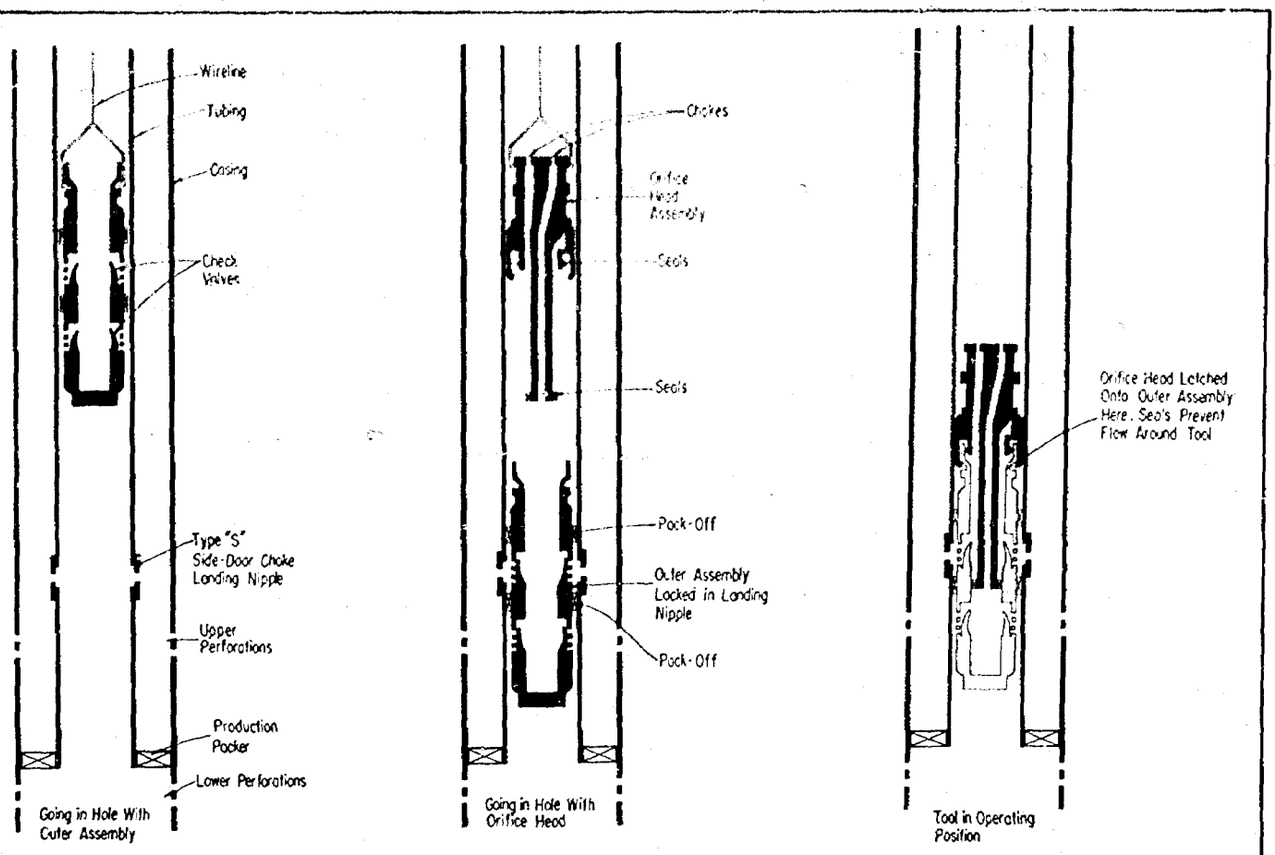


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This new type dual completion reduces costs, boosts recovery

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Sun Oil Company, Beaumont, Texas

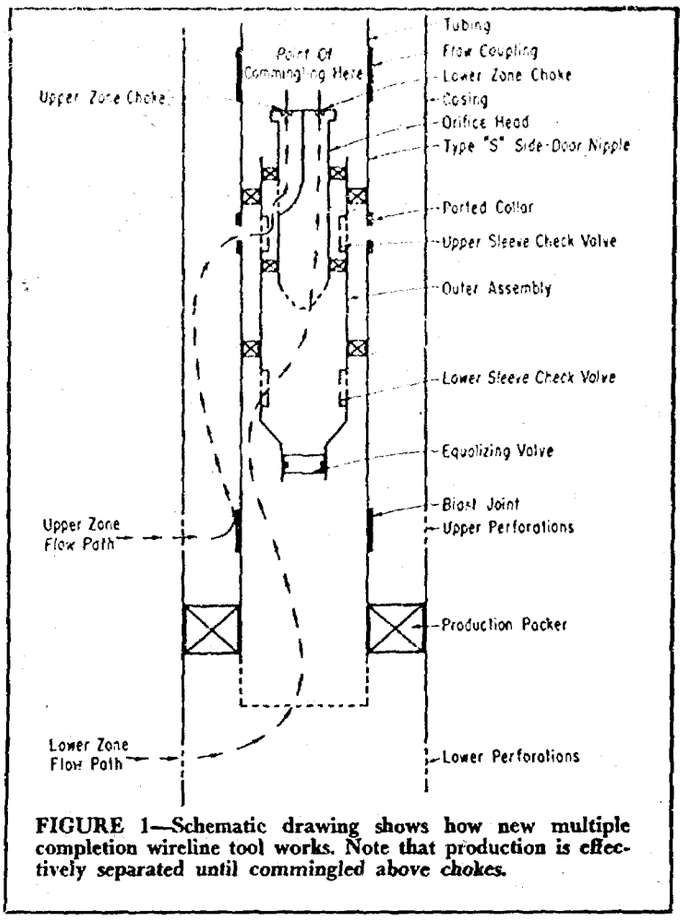


FIGURE 1—Schematic drawing shows how new multiple completion wireline tool works. Note that production is effectively separated until commingled above chokes.

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.
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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

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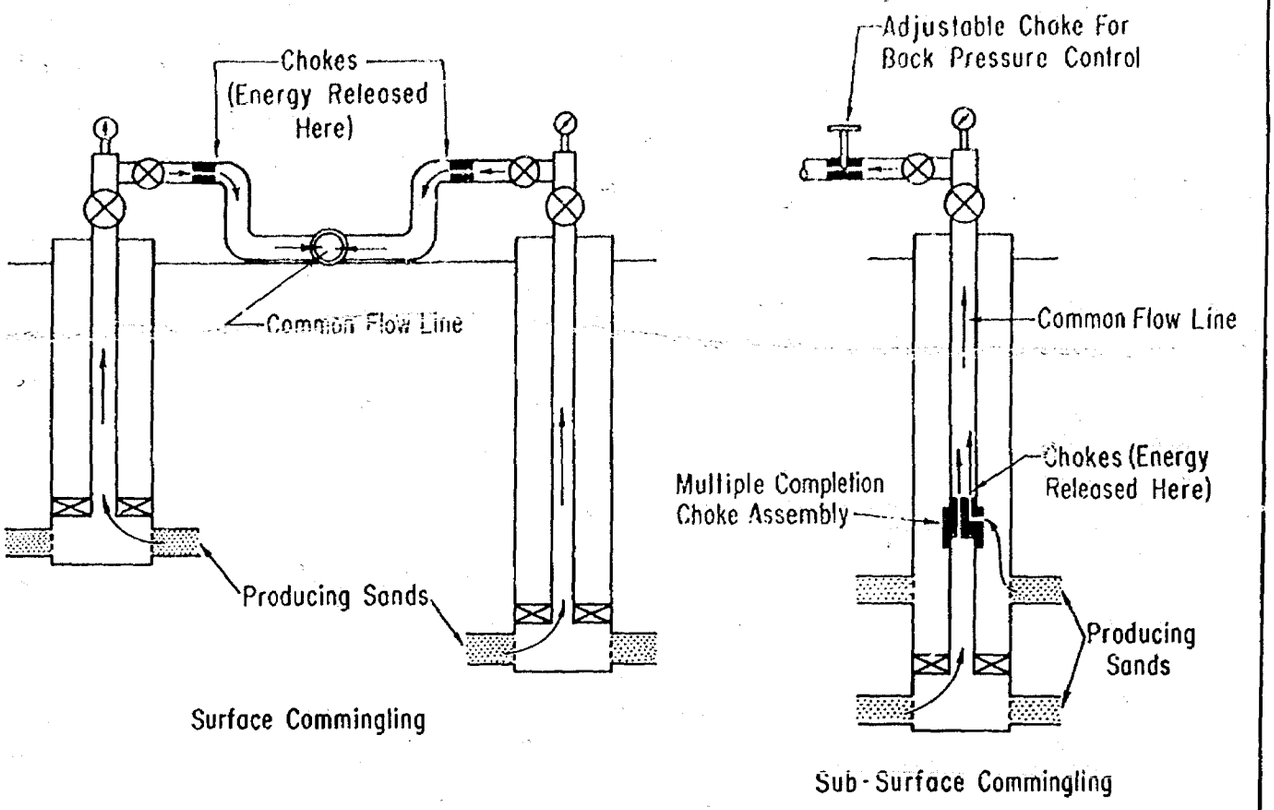


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Steps involved in installation of the assembly are illustrated in Figure 4. When a choke change is required, the orifice head is pulled leaving the outer assembly in place. The check valves in the outer assembly prevent flow from one zone to the other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

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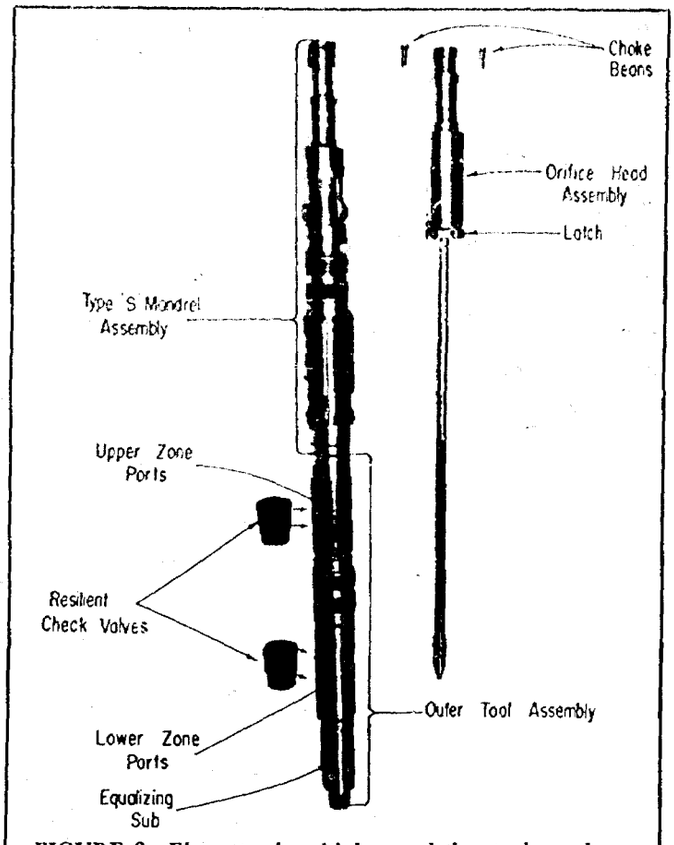


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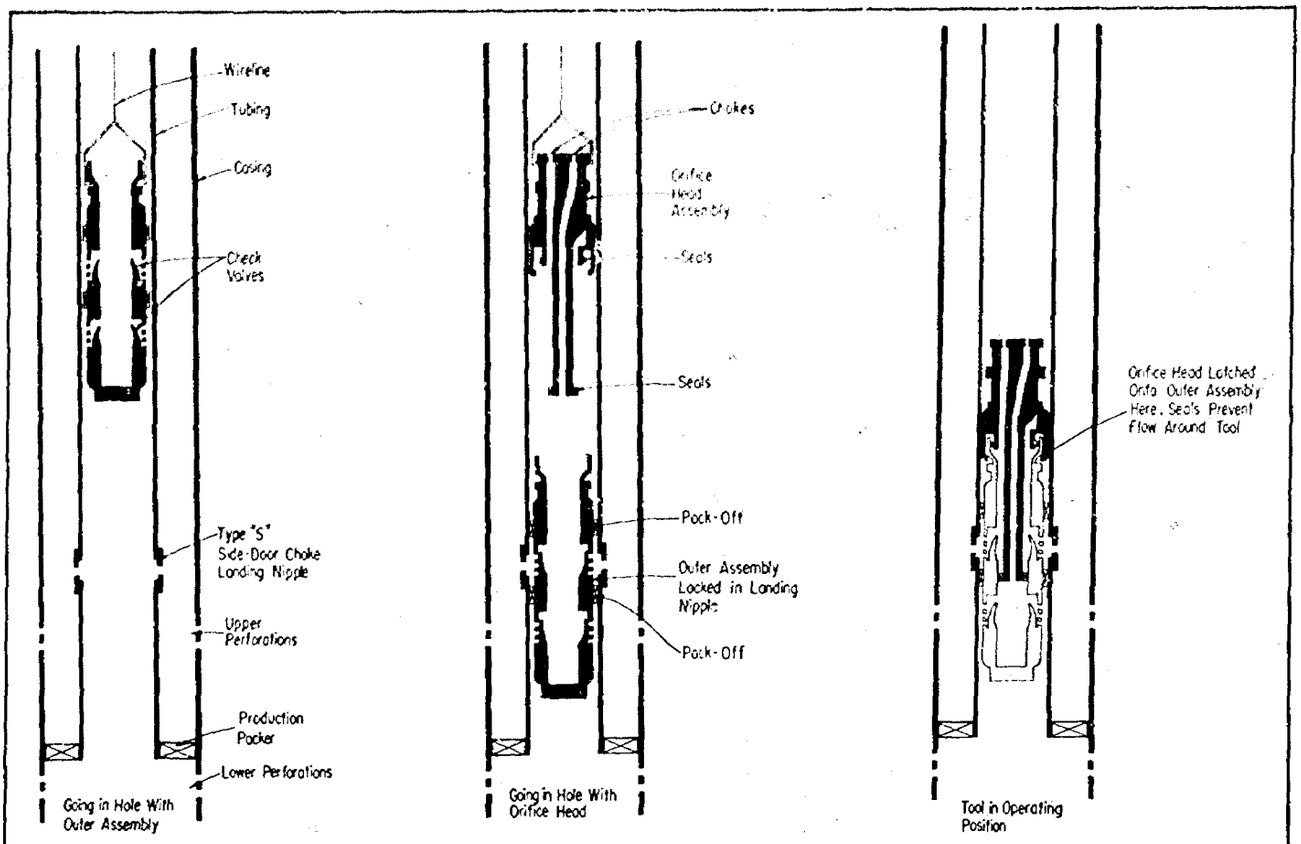


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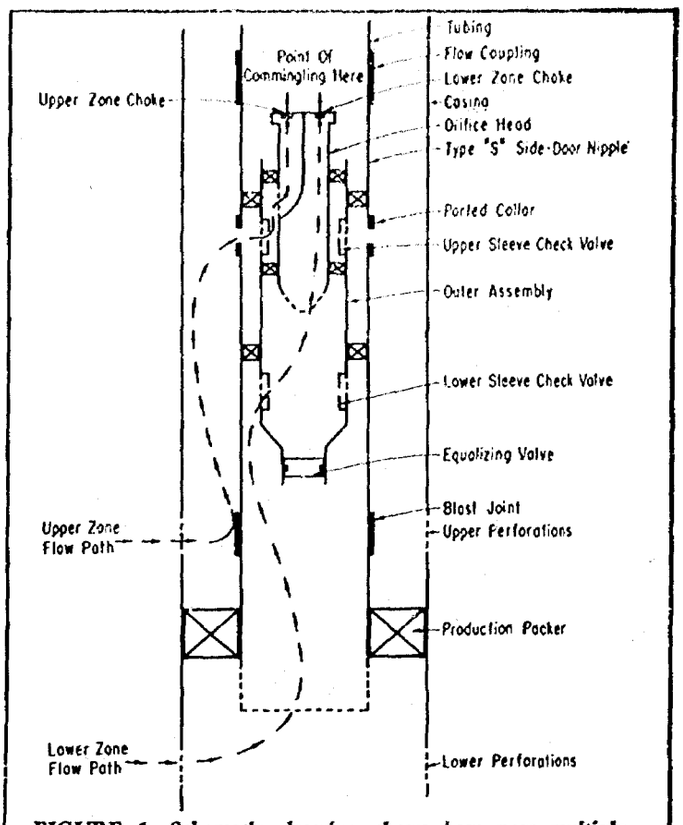


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By J. W. Hodges, Administrative Engineer, Sun Oil Company, Beaumont, Texas

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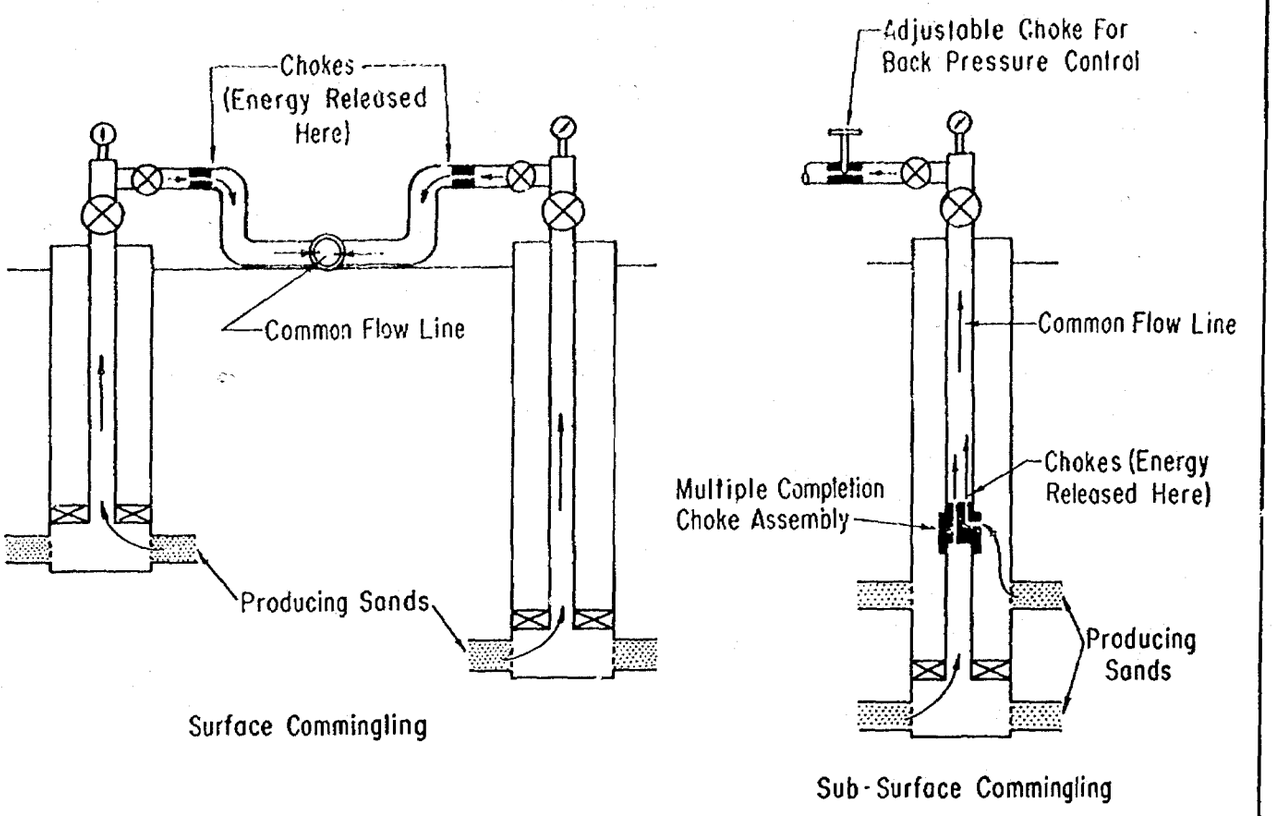


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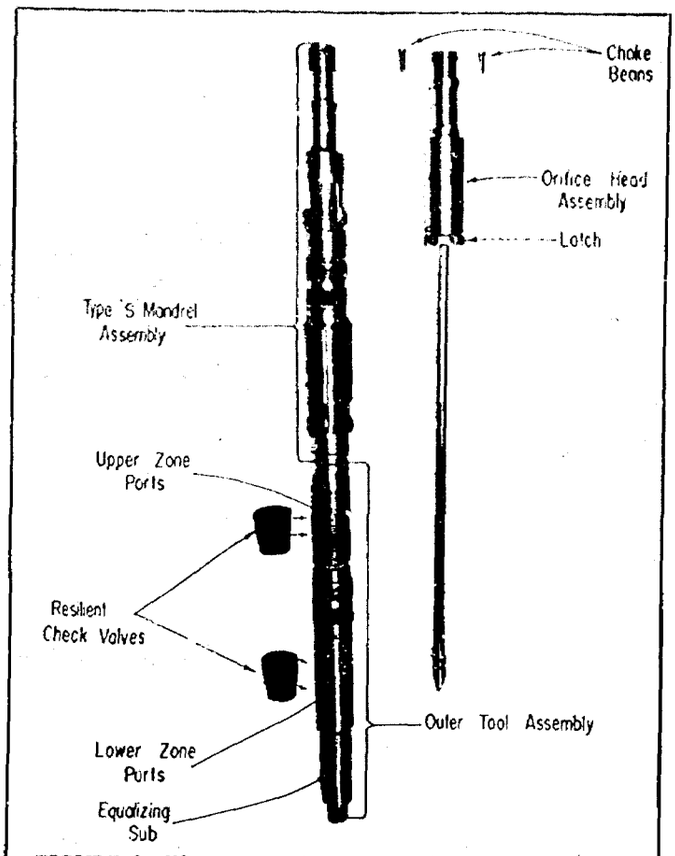


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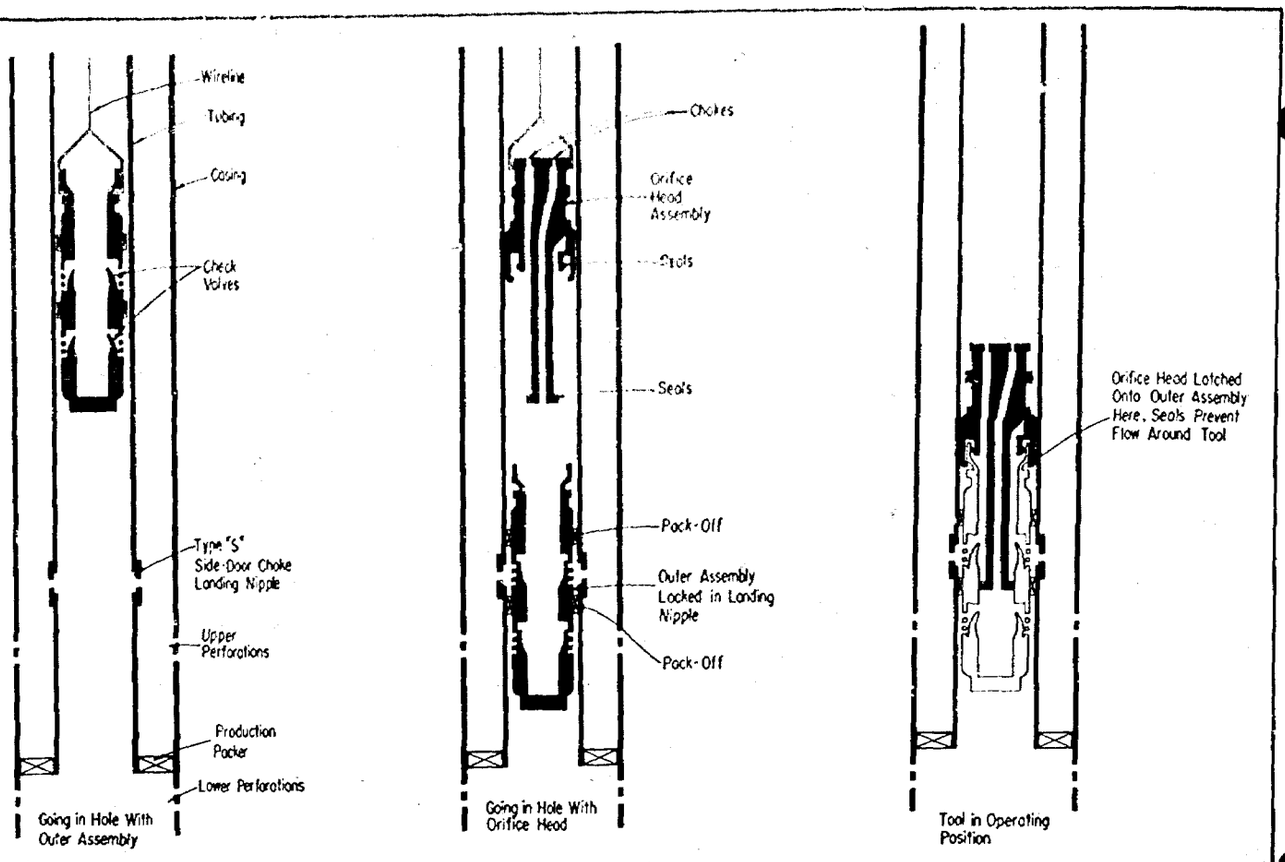


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Field tests of the multiple completion tool have demonstrated it to be a means of increasing current income as well as ultimate recovery at reduced operating costs. This should appeal to all segments of the industry —oil companies, royalty owners and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



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.

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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

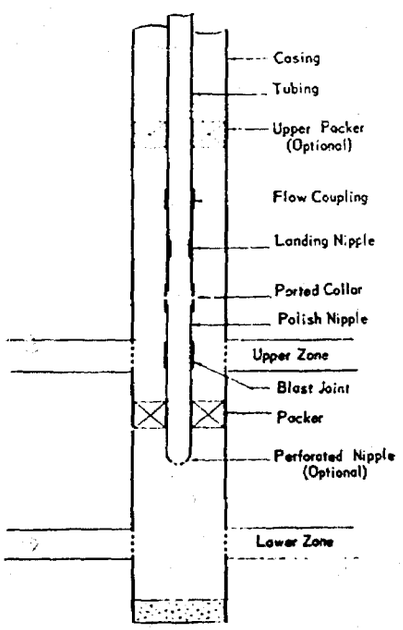


Fig. 1—Well properly equipped for multiple-completion choke assembly.

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 section, 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

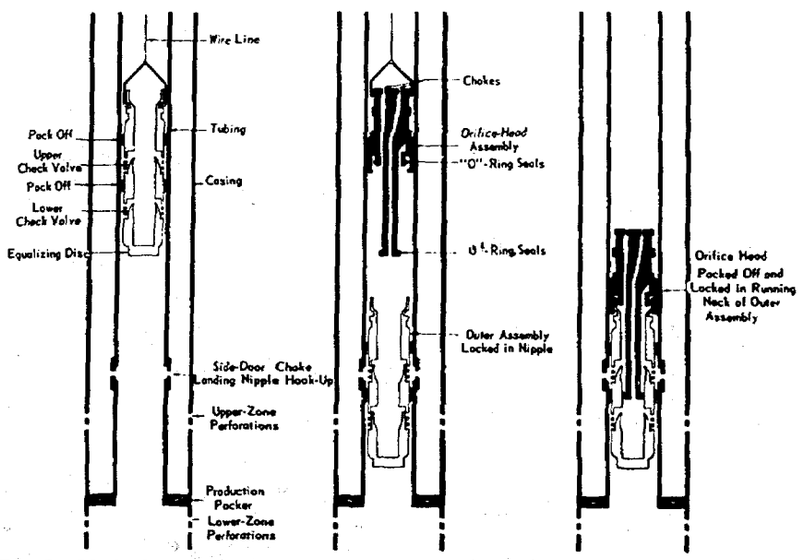


Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

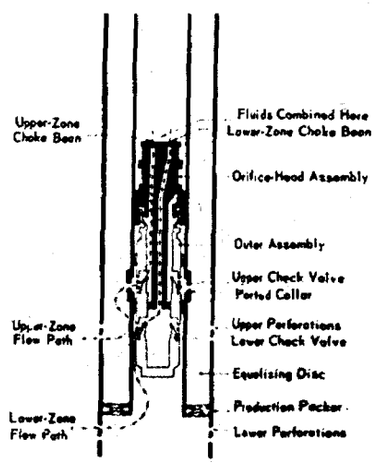


Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

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[1] 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)	300
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	0 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

Date	Surface Tubing Pressure (psig)	Measured Production Total Liquid (B/D)	Measured Production Total Gas (Mcf/D)	Calculated Production Upper Zone Oil (B/D)	Calculated Production Upper Zone Gas (Mcf/D)	Calculated Production Lower Zone Condensate (B/D)	Calculated Production Lower Zone 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) Surface	Tubing Pressure (psig) Inlet	Production Condensate (B/D)	Production Gas (Mcf/D)
790	1,466	38.40	726,802
930	1,549	39.41	726,802
1,068	1,835	37.34	708,654
1,250	2,091	32.12	638,787
1,335	2,345	30.06	535,196
1,475	2,517	22.82	454,251
1,600	3,125	12.44	222,678

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. 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).

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

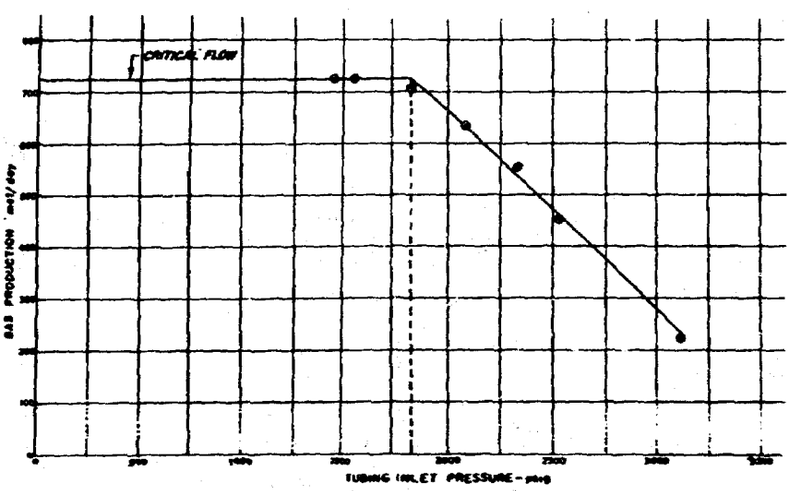


Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

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.

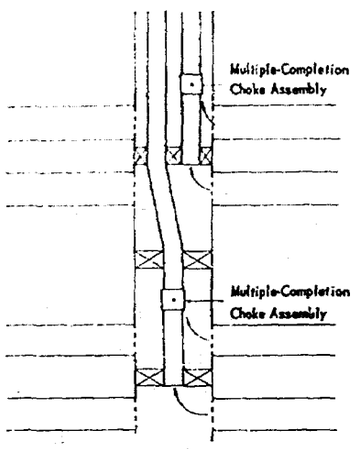


Fig. 5—Two-string quadruple completion.

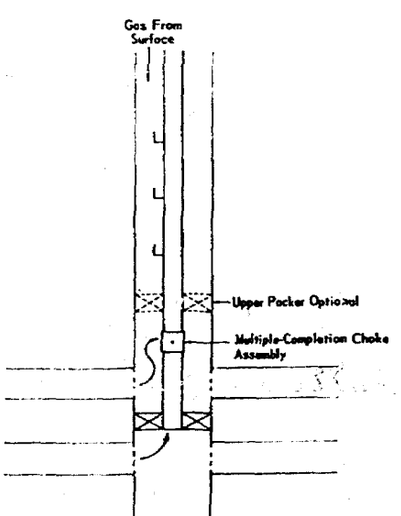


Fig. 6—Gas-lifting two zones with one string of flow valves.

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.

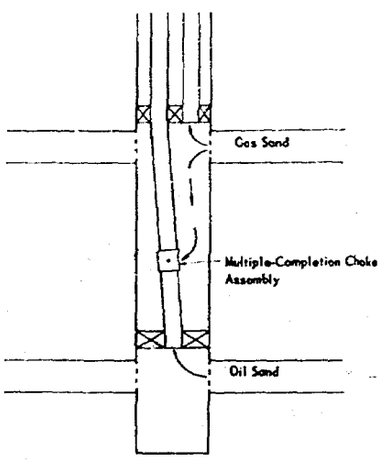


Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

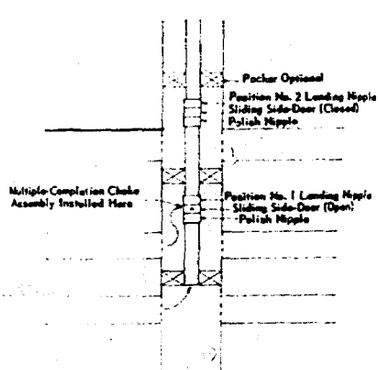


Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

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.

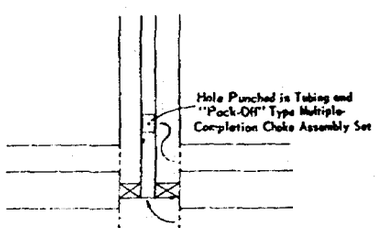


Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

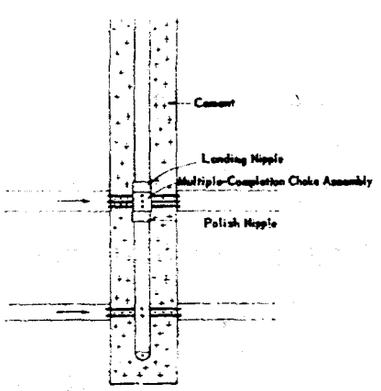


Fig. 10—One-string dual tubingless completion.

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.

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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

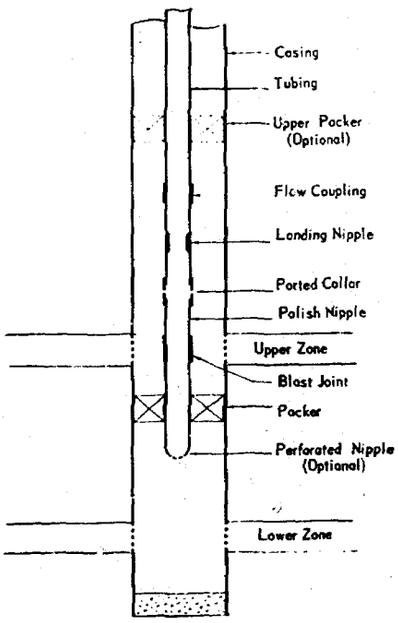


Fig. 1—Well properly equipped for multiple-completion choke assembly.

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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 section, 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

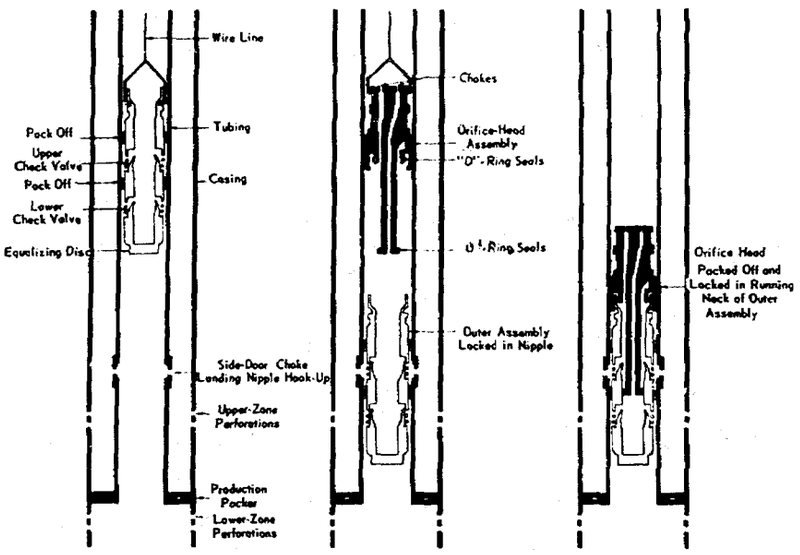


Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

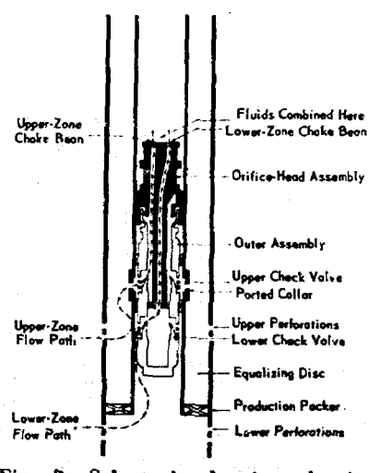


Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

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.

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

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 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

Date	Surface Tubing Pressure (psig)	Measured Production Total Liquid (B/D)	Measured Production Total Gas (Mcf/D)	Calculated Production Upper Zone Oil (B/D)	Calculated Production Upper Zone Gas (Mcf/D)	Calculated Production Lower Zone Condensate (B/D)	Calculated Production Lower Zone Gas (Mcf/D)
6-16-60	900	28.92	498	10.75*	239*	18.17	259
6-17-60	900	30.07	462	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) Surface	Tubing Pressure (psig) Inlet	Production Condensate (B/D)	Production Gas (Mcf/D)
790	1,466	38.40	726,882
930	1,569	39.41	726,882
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	23.82	454,251
1,600	3,125	12.44	222,878

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. 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).

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

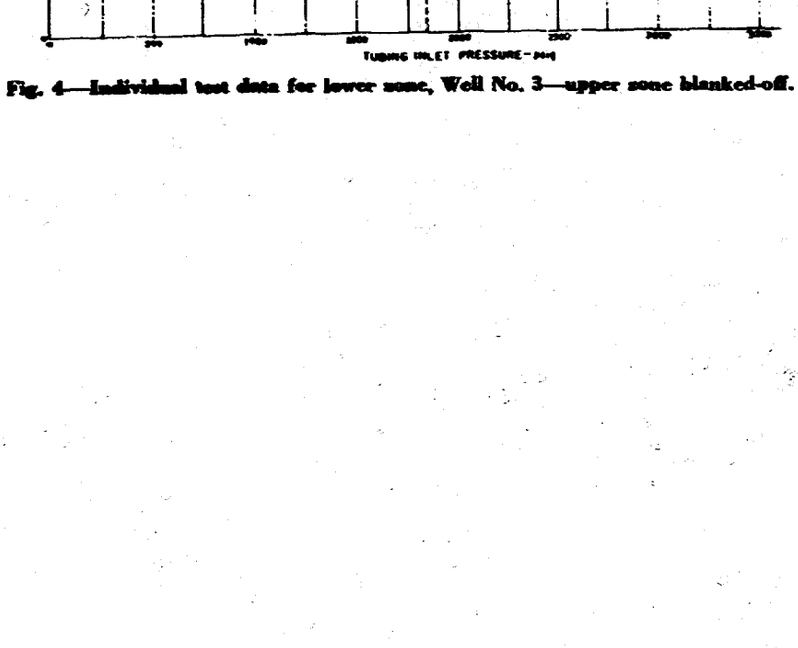


Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

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 (2⅛ 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.

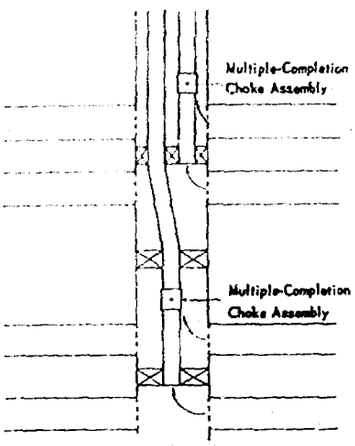


Fig. 5—Two-string quadruple completion.

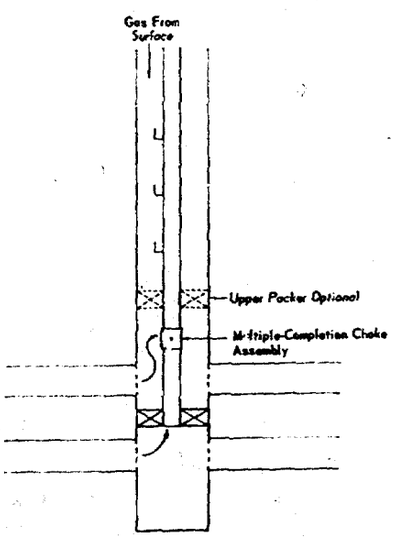


Fig. 6—Gas-lifting two zones with one string of flow valves.

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.

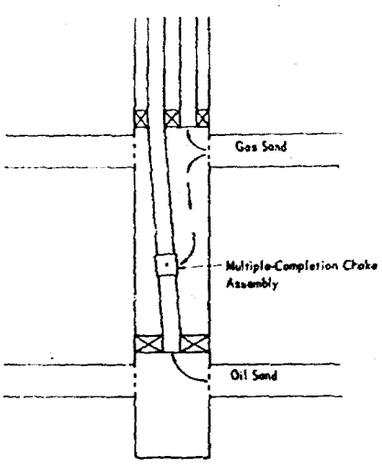


Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

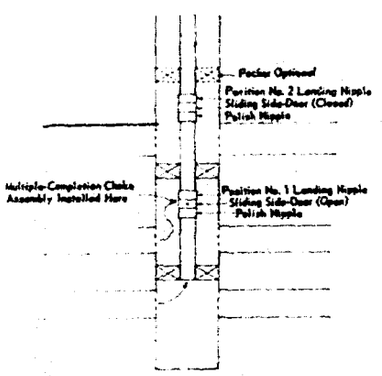


Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

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.

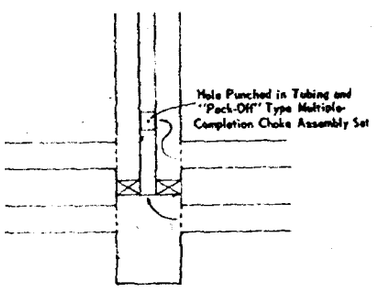


Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

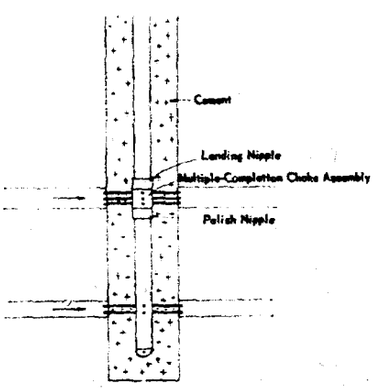


Fig. 10—One-string dual tubingless completion.

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.

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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

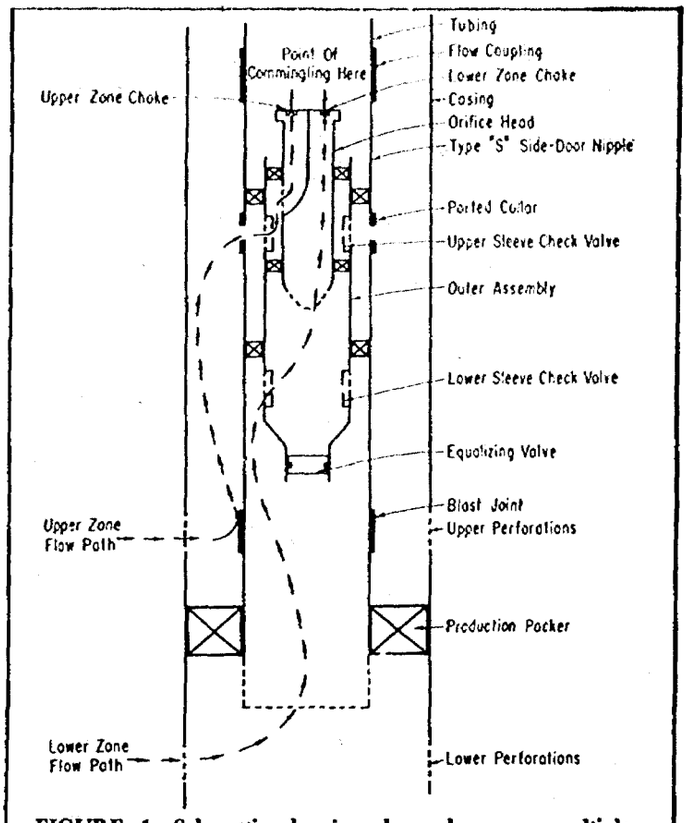


FIGURE 1—Schematic drawing shows how new multiple completion wireline tool works. Note that production is effectively separated until commingled above chokes.

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

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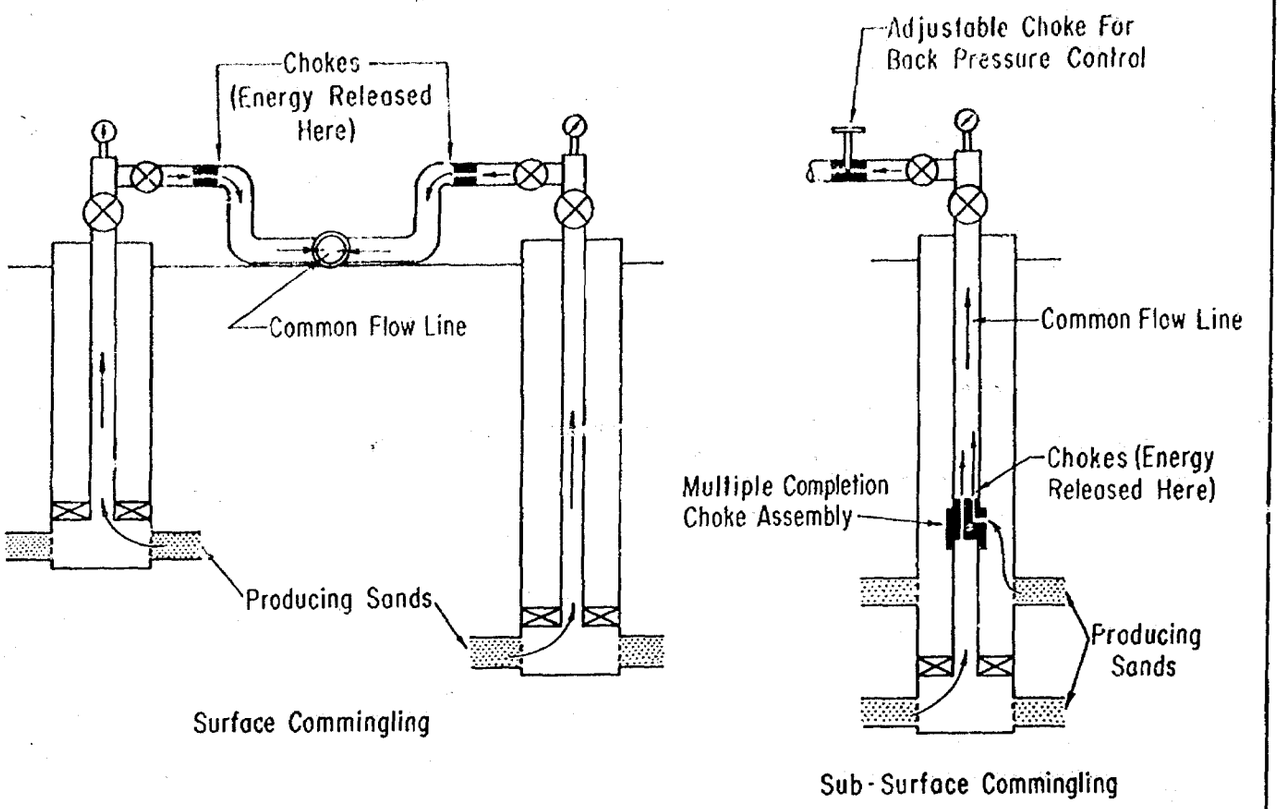


FIGURE 2—Downhole commingling is analoguous to surface commingling except that the pressure reduction is accomplished at the bottom of the hole where energy in released gas can be used.

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 $\frac{5}{64}$-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.

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 analogous 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.

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.

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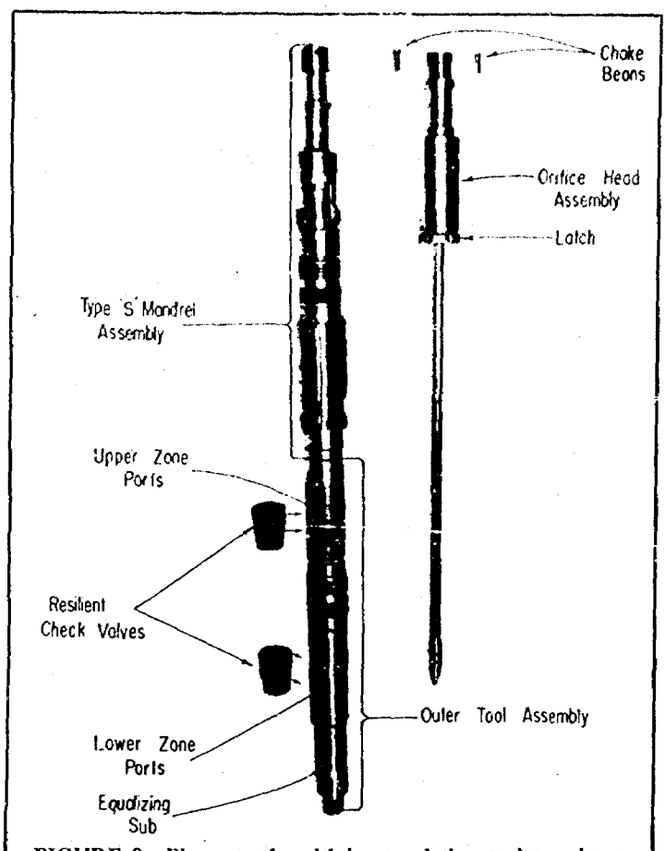


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1-27-61	3-3/64"	6.38	175	27,500

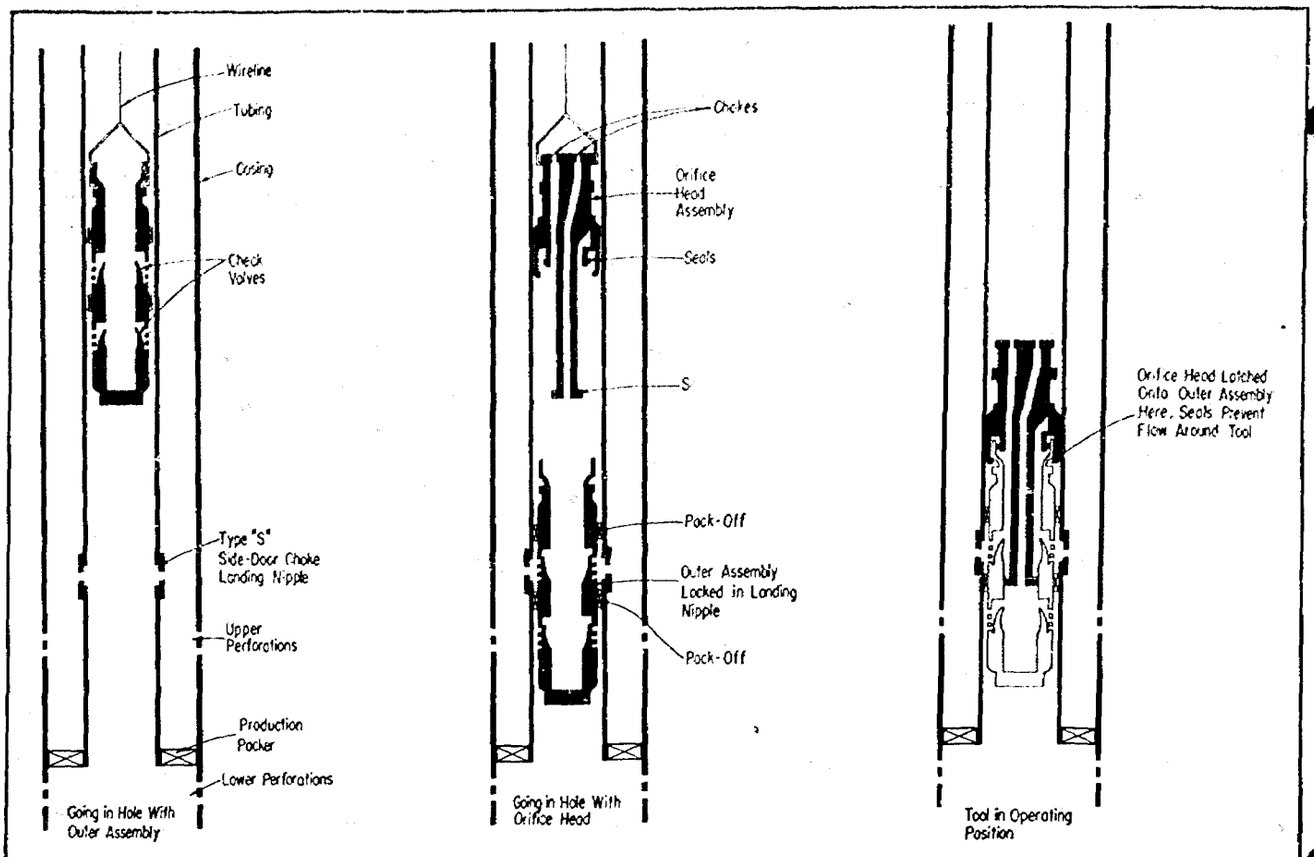


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This new type dual completion reduces costs, boosts recovery

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

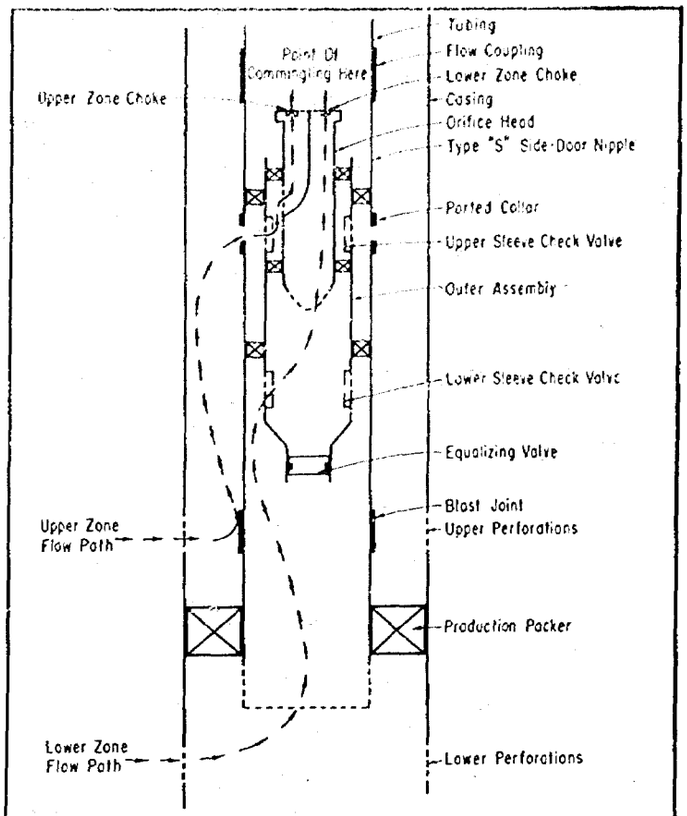


FIGURE 1—Schematic drawing shows how new multiple completion wireline tool works. Note that production is effectively separated until commingled above chokes.

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

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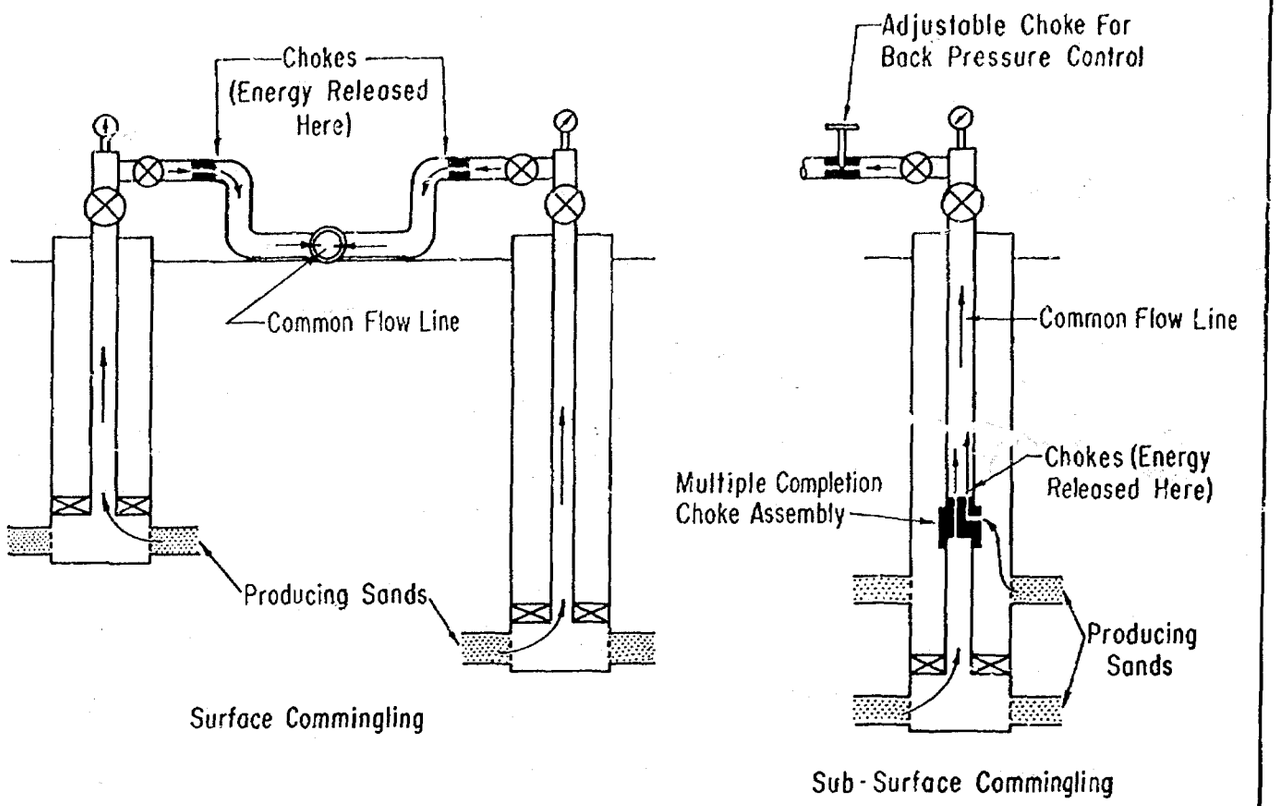


FIGURE 2—Downhole commingling is analoguous to surface commingling except that the pressure reduction is accomplished at the bottom of the hole where energy in released gas can be used.

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.

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.

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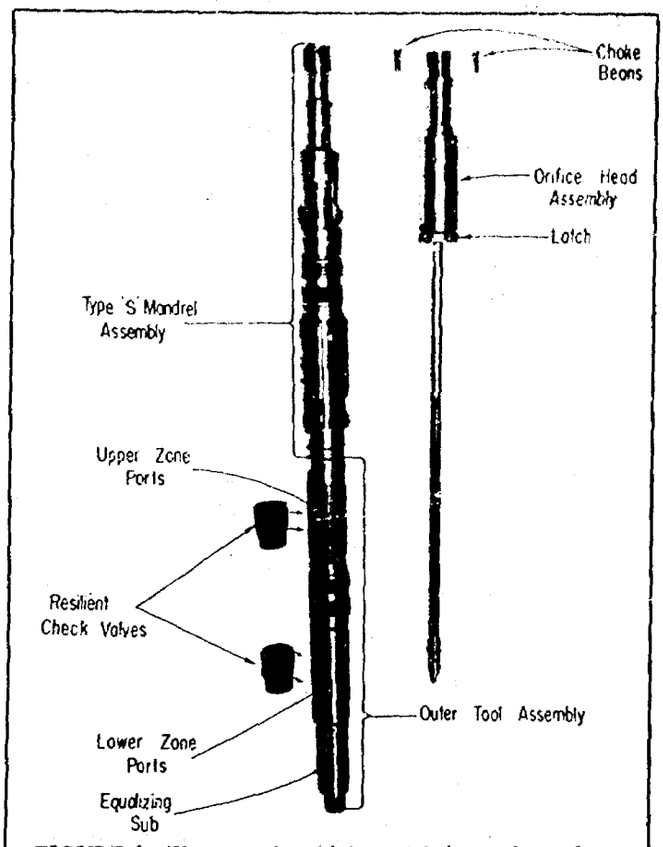


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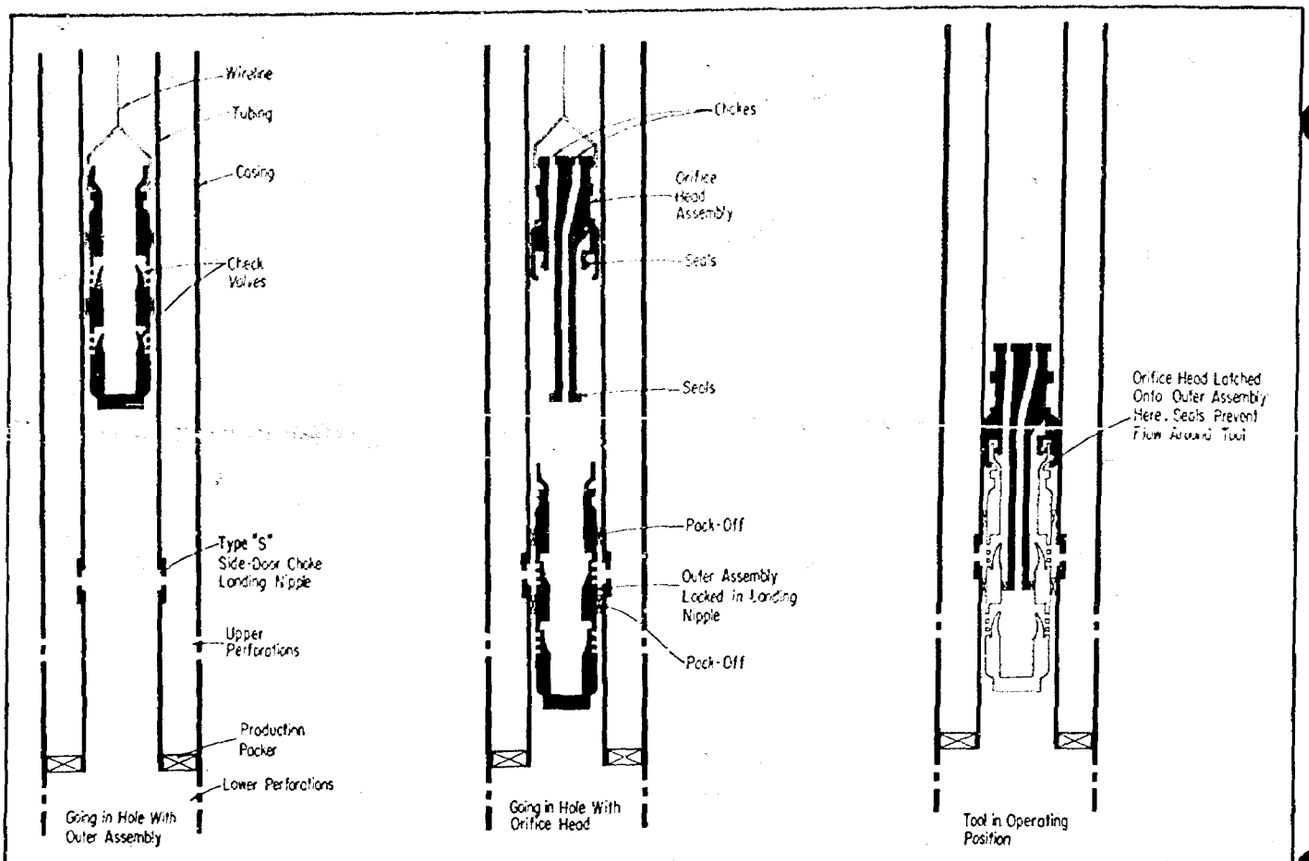


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New Tool Permits Simultaneous Production of Two Reservoirs Through the Same Flow String

J. W. HODGES
MEMBER AIME

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.

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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

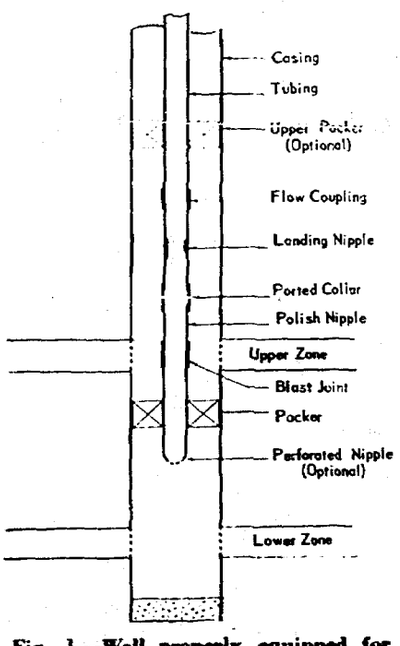


Fig. 1—Well properly equipped for multiple-completion choke assembly.

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 section, 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	436	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

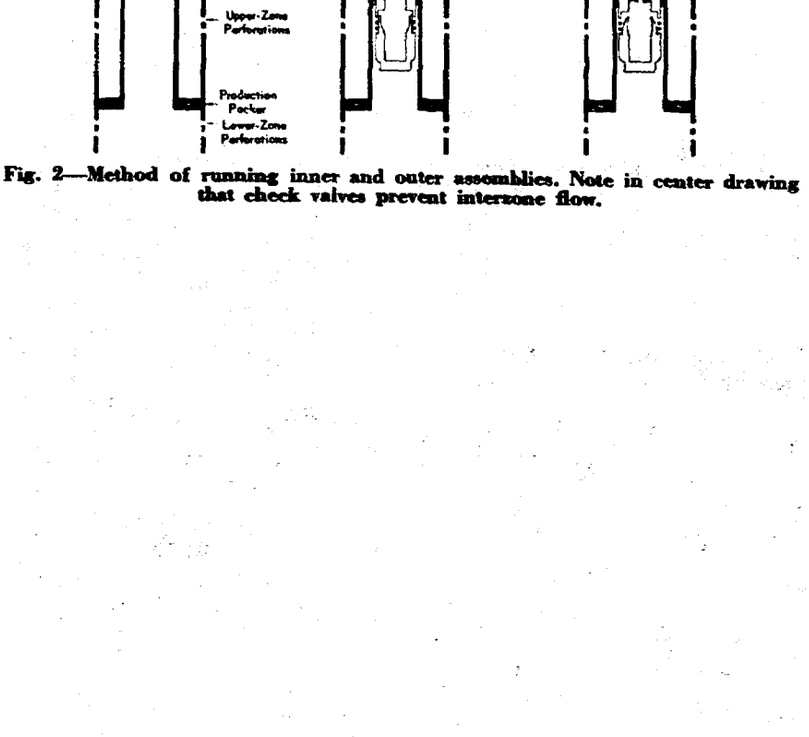


Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.



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

Date	Surface Tubing Pressure (psig)	Measured Production Total Liquid (B/D)	Measured Production Total Gas (Mcf/D)	Calculated Production Upper Zone Oil (B/D)	Calculated Production Upper Zone Gas (Mcf/D)	Calculated Production Lower Zone Condensate (B/D)	Calculated Production Lower Zone Gas (Mcf/D)
6-16-60	900	28.92	498	10.75*	239*	18.17	259
6-17-60	900	30.07	462	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) 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
1,680	3,125	12.44	222,878

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. 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).

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

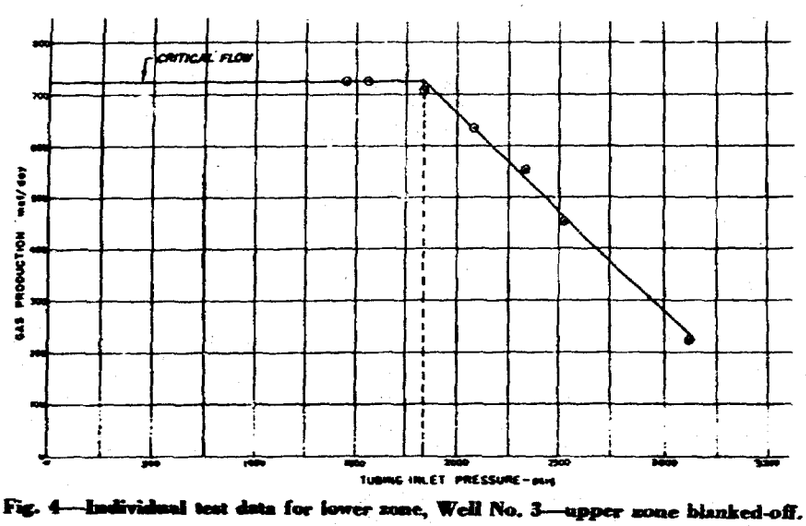


Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

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.

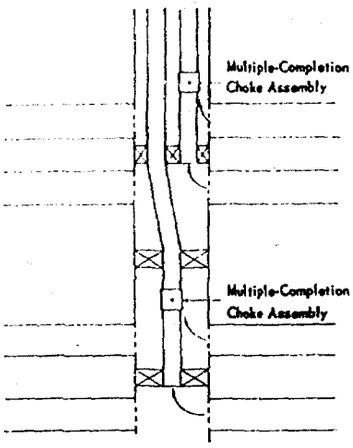


Fig. 5—Two-string quadruple completion.

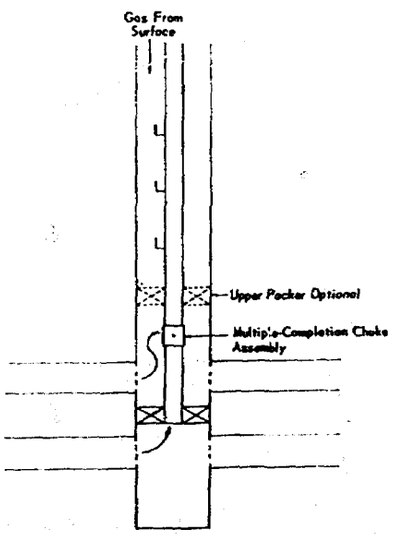


Fig. 6—Gas-lifting two zones with one string of flow valves.

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.

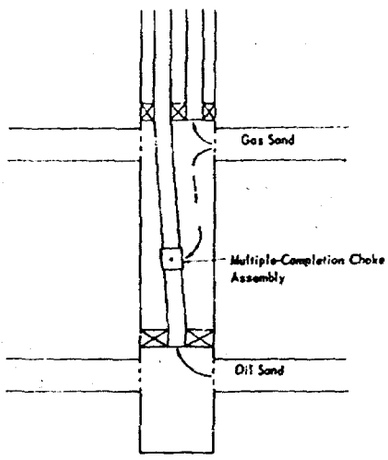


Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

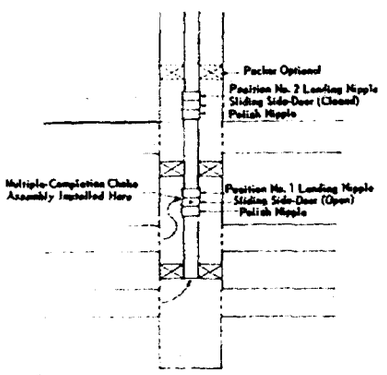


Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

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.

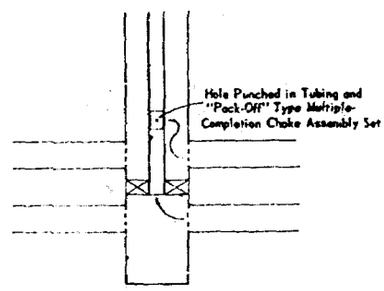


Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

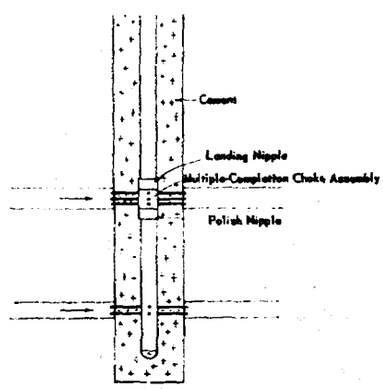


Fig. 10—One-string dual tubingless completion.

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.

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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.

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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

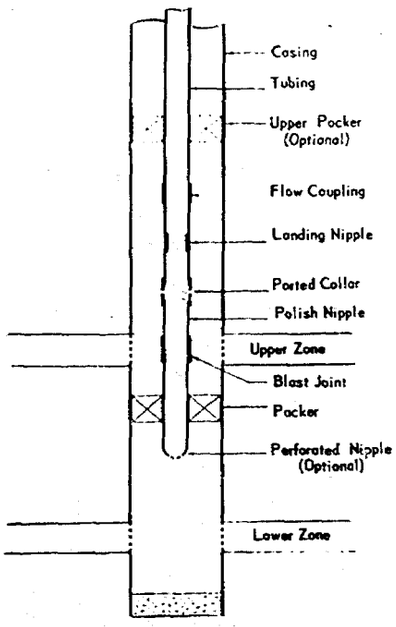


Fig. 1—Well properly equipped for multiple-completion choke assembly.

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 section, 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

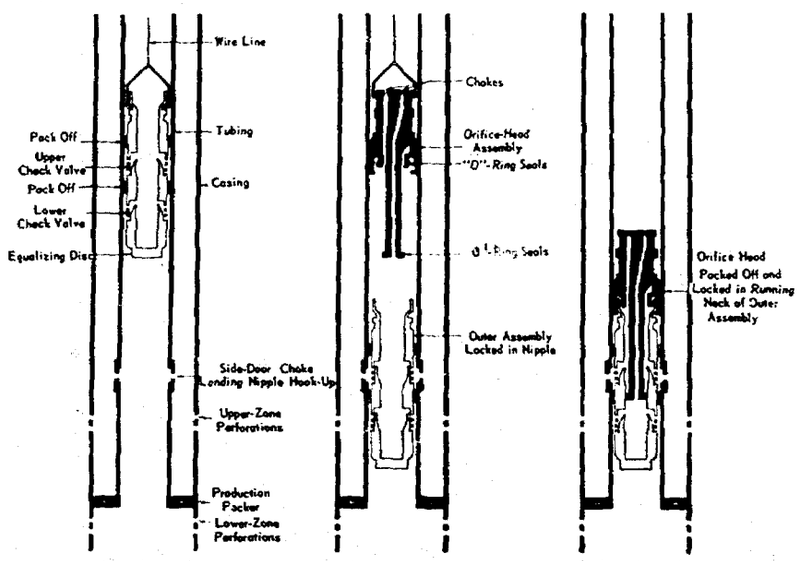


Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

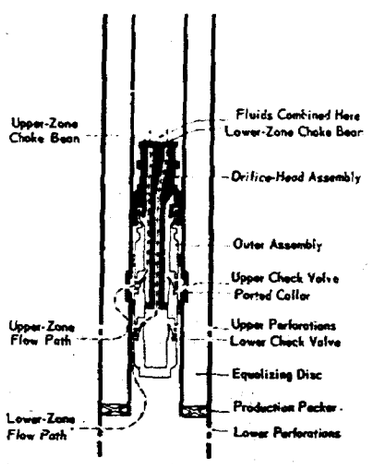


Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

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
		[illegible]983	6,500	129 Oil	945
5	Kinder, La.	7,394	3,290	7 Oil, 15 SW	643
		8,396	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
		4,783	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 Total Liquid (B/D)	Measured Production Total Gas (Mcf/D)	Calculated Production Upper Zone Oil (B/D)	Calculated Production Upper Zone Gas (Mcf/D)	Calculated Production Lower Zone Condensate (B/D)	Calculated Production Lower Zone 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	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

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	922	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

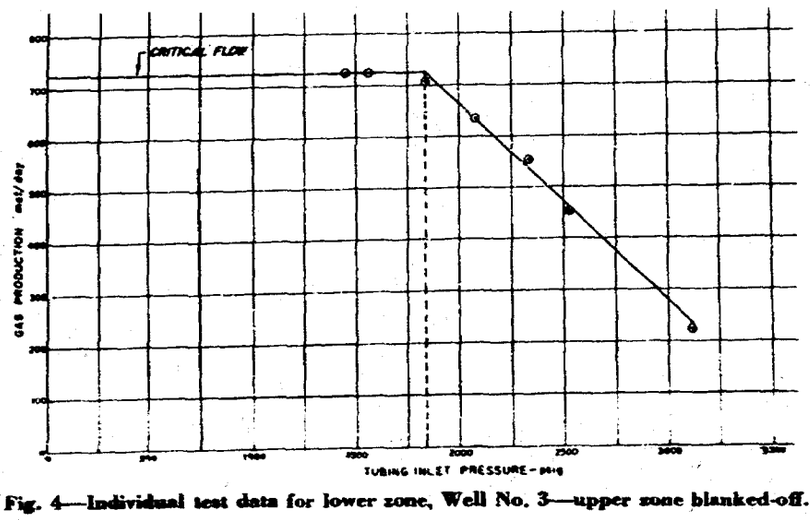


Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

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	41,500 (7⅝ in.)	39,600 (5½ in.)
Tubing	27,000 (2⅞ in.)	11,200 (2⅞ 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 Kitder 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 COMPLETIONS

	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	2⅞	5,600	None	—	—	4,500	2⅞	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.

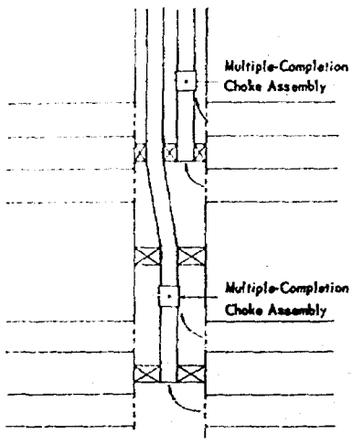


Fig. 5—Two-string quadruple completion.

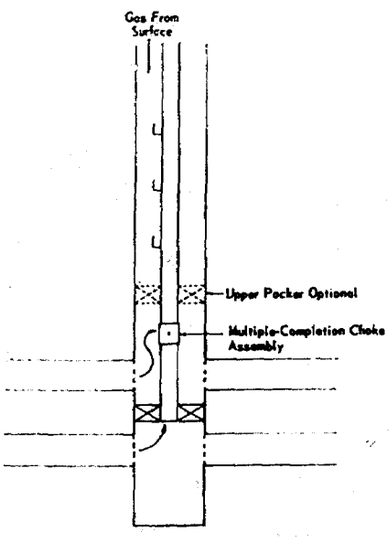


Fig. 6—Gas-lifting two zones with one string of flow valves.

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.

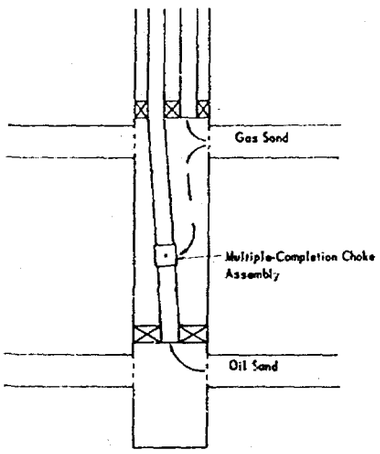


Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

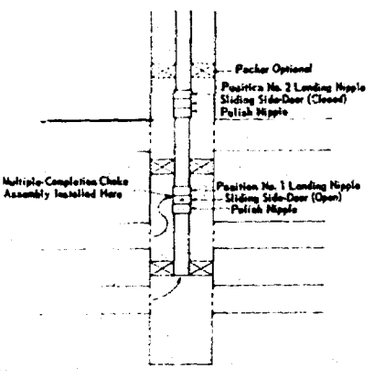


Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

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.

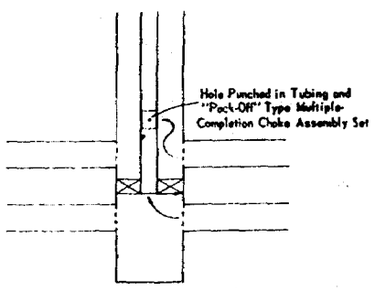


Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

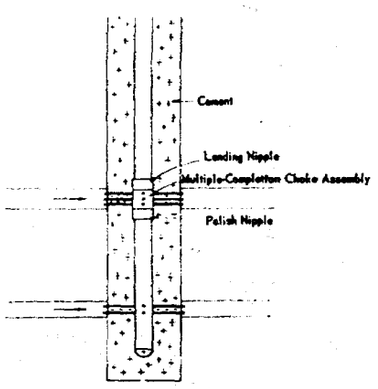


Fig. 10—One-string dual tubingless completion.

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.

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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

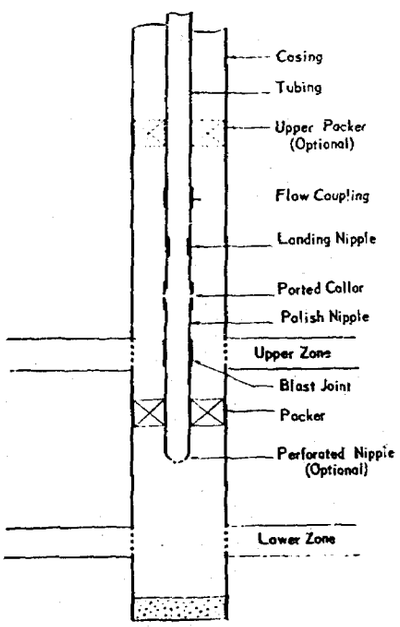


Fig. 1—Well properly equipped for multiple-completion choke assembly.

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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

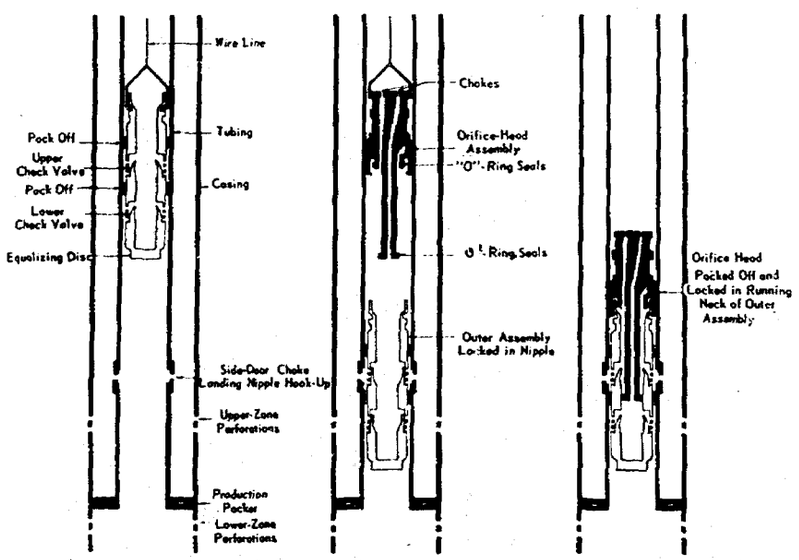


Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

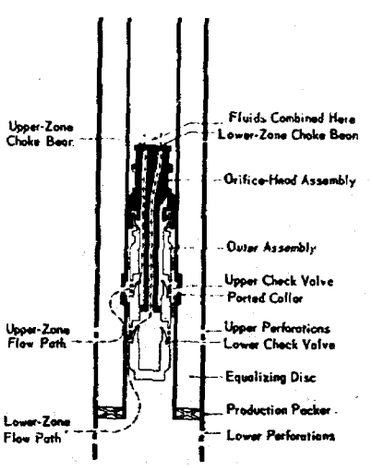


Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

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

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 tails 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.

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

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 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		Gas-Oil Ratio (cu ft/bbl)
		Oil (B/D)	Gas (Mcf/D)	
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	462	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) Surface	Tubing Pressure (psig) Inlet	Production Condensate (B/D)	Production Gas (Mcf/D)
790	1,466	38.40	723,802
950	1,549	39.41	726,807
1,060	1,835	37.34	708,454
1,250	2,091	32.12	638,787
1,335	2,345	30.86	555,196
1,475	2,517	22.82	454,251
1,660	3,125	12.44	222,078

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	937	1,200
107	900	1,450

Well No. 1

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).

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

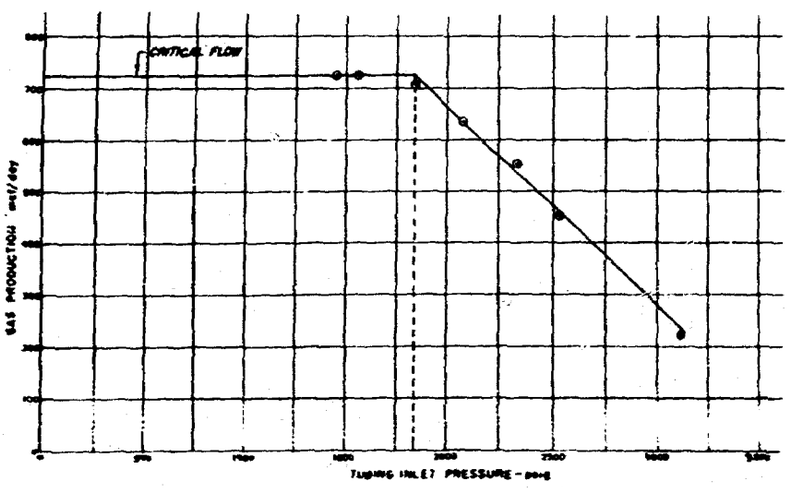


Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

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.

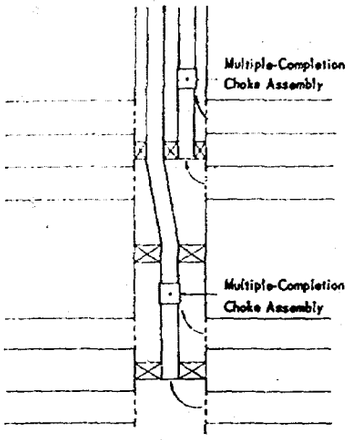


Fig. 5—Two-string quadruple completion.

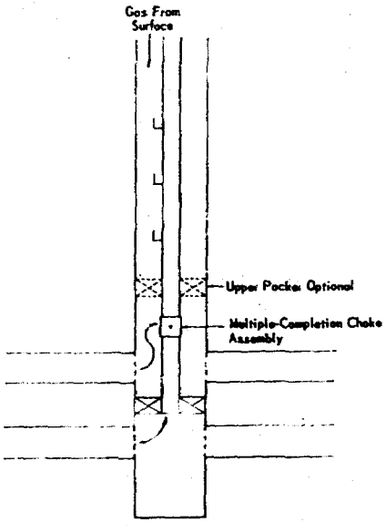


Fig. 6—Gas-lifting two zones with one string of flow valves.

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.

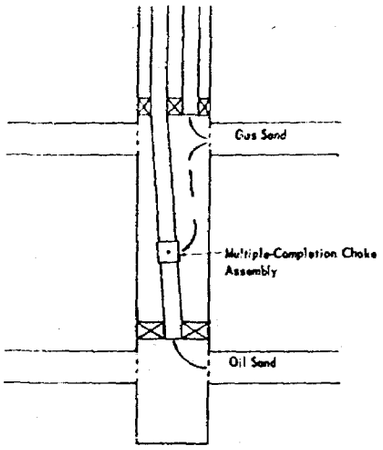


Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

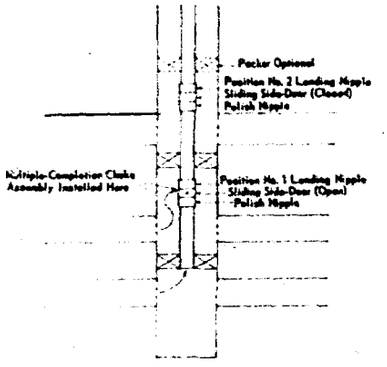


Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

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.

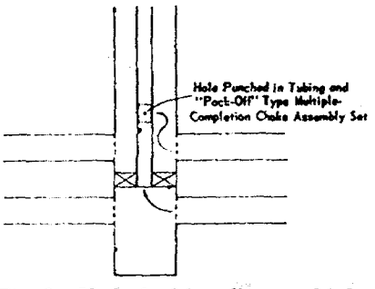


Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

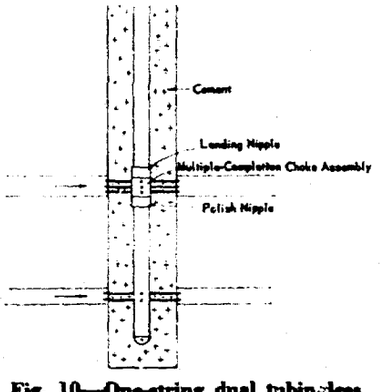


Fig. 10—One-string dual tubingless completion.

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.

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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

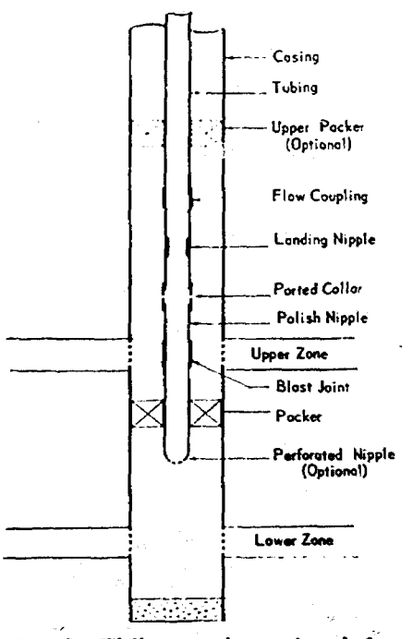


Fig. 1—Well properly equipped for multiple-completion choke assembly.

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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)	5,600	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

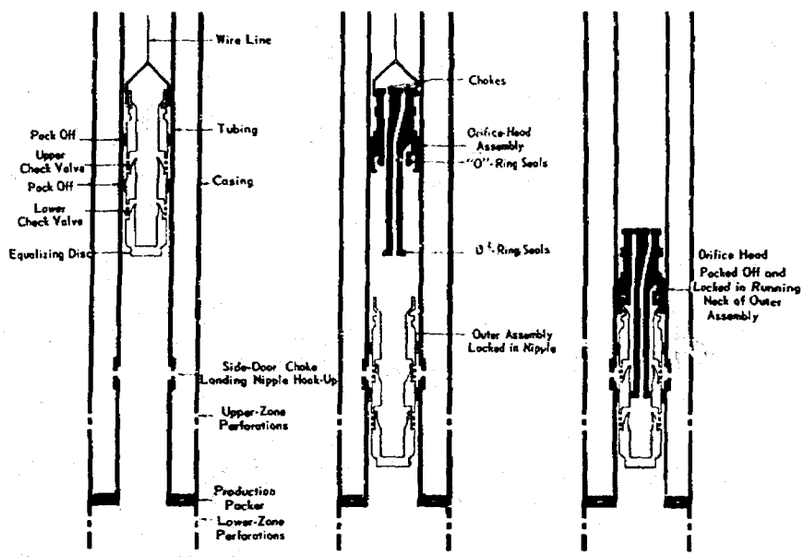


Fig. 2—Method of running inner and outer assemblies. Note in center drawing that check valves prevent interzone flow.

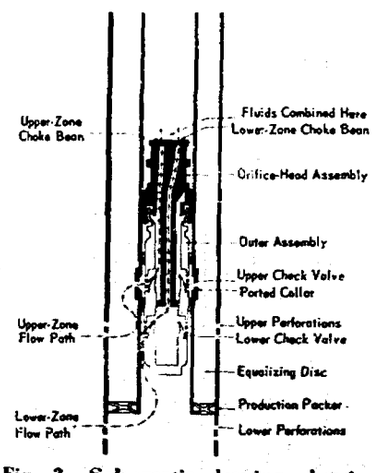


Fig. 3—Schematic drawing showing operation of multiple-completion choke assembly.

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	0 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

Date	Surface Tubing Pressure (psig)	Measured Production Total Liquid (B/D)	Measured Production Total Gas (Mcf/D)	Calculated Production Upper Zone Oil (B/D)	Calculated Production Upper Zone Gas (Mcf/D)	Calculated Production Lower Zone Condensate (B/D)	Calculated Production Lower Zone Gas (Mcf/D)
6-16-60	900	28.92	498	10.75*	239*	18.17	259
6-17-60	900	30.07	462	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) 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	708,454
1,250	2,091	32.12	638,787
1,335	2,345	30.06	555,196
1,475	2,517	22.82	454,251
1,680	3,125	12.44	222,878

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
153	919	150
157	936	250
149	905	925
133	972	1,075
122	957	1,200
100	900	1,450

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).

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

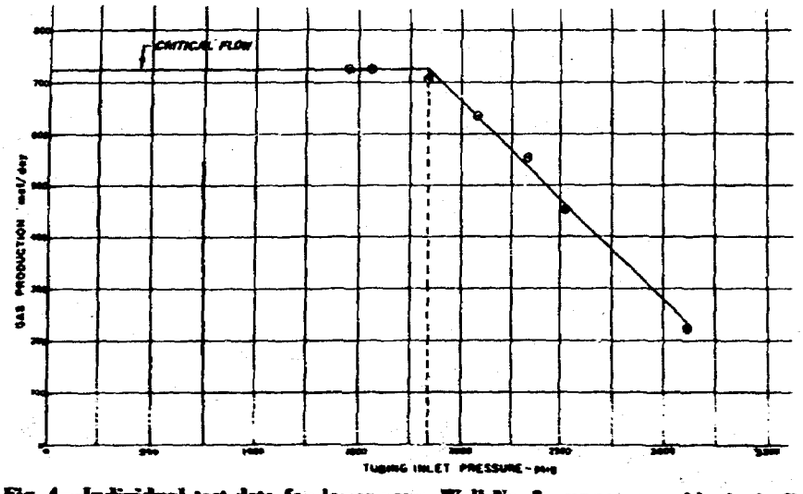


Fig. 4—Individual test data for lower zone, Well No. 3—upper zone blanked-off.

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 State-Wide 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.

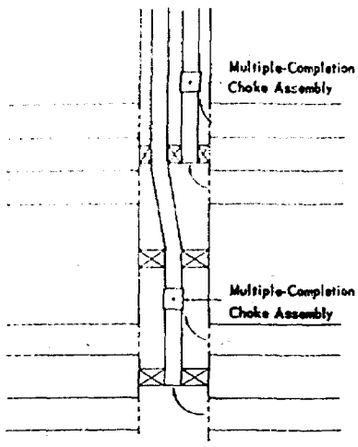


Fig. 5—Two-string quadruple completion.

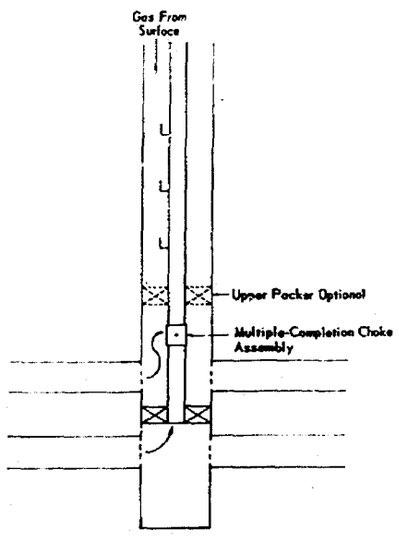


Fig. 6—Gas-lifting two zones with one string of flow valves.

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.

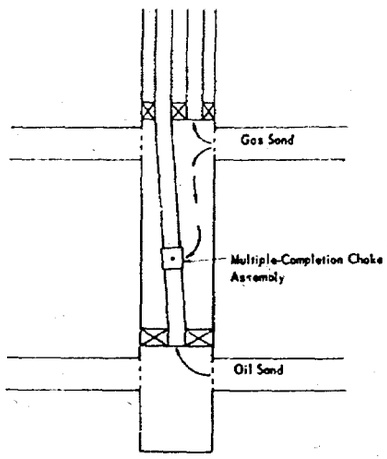


Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

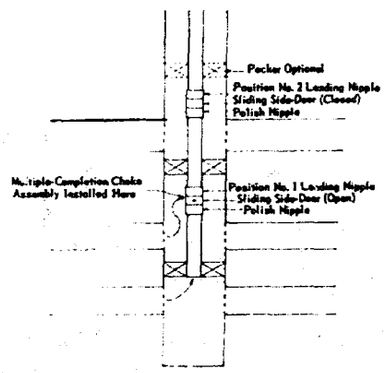


Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

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.

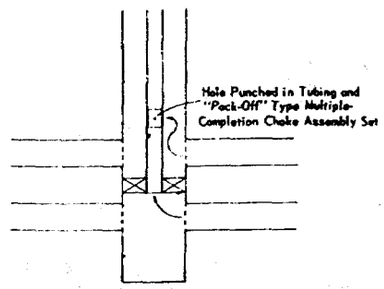


Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

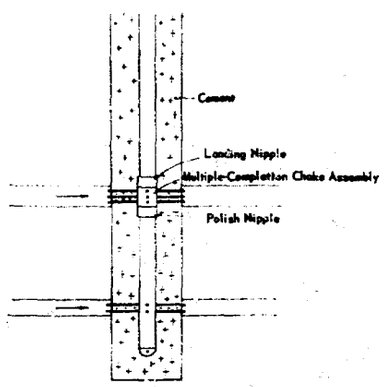


Fig. 10—One-string dual tubingless completion.

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.

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WEST LINDRITH BLOCK

Rio Arriba Co., New Mexico

CONOCO

CONTINENTAL OIL COMPANY

P. O. Box 3312
Durango, Colorado
August 11, 1964

New Mexico Oil Conservation Commission
P. O. Box 2088
Santa Fe, New Mexico

DOCKET MAILED
Date 8-18-64

Attention: Mr. A. L. Porter - Secretary Director

Gentlemen:

A hearing before the New Mexico Oil Conservation Commission is requested for the purpose of presenting application by Continental Oil Company to install a downhole commingling tool on a test basis in an existing Gallup-Dakota dual-oil completion well. The test well is Jicarilla 28 Well No. 1, located in Unit J, Section 28, T25N, R4W, Rio Arriba County, New Mexico.

The two sources of supply are commonly owned and the proposed downhole installation is intended to prevent communication between the two reservoirs at all times. Application on a one-well test basis is proposed so that data and procedures for such tests as packer leakage and communication tests and production allocation tests can be established. The commingling installation will be observed to determine the effectiveness of the installation.

The primary purpose of the installation and testing is to establish a method whereby further development of the 16-section West Lindrith block in T25N, R4W, can be economically justified. Past producing histories indicate that further development cannot be economically justified by conventional single and dual completion methods and present producing methods.

The following data and exhibits are attached for preliminary information:

1. Lease plat showing wells on the lease and pools from which each are producing.

2. Data requirements for surface commingling installations.

3. Log of Jicarilla 28 Well No. 1, showing formation tops and location of present retainer production packer and perforations in the Gallup and Dakota formation.

4. Schematic diagram of Otis Engineering Corporation's "Dual Flow Choke Assembly" downhole commingling tool.

5. Schematic diagram showing present and proposed installations in Jicarilla 28 Well No. 1.

6. Composite Performance Curve for a typical Jicarilla Gallup and Dakota well.

If additional information is required, please advise.

Very truly yours,

W. D. Haley
District Manager
Durango District
Production Department

CAB/ca

cc: Mr. E. A. Austin, Continental Oil Company, Denver, Colorado (2)
U. S. Geological Survey, Roswell, New Mexico (1)

DATA TO SUPPORT NO. 3 ABOVE STATED FACTUAL FINDINGS

Average Daily Oil Production for 90-Day Period:

Jicarilla 23 Well No. 1	Gallup	Dakota
May	13 BOPD	9 BOPD
June	13 BOPD	5 BOPD
July	10 BOPD	8 BOPD

Per Unit Allocable: Gallup - 126 BOPD
Dakota - 134 BOPD
Crude Purchaser: Llaves Pipeline Ltd. - Farmington, New Mexico
Royalty Interest Owner: Jicarilla Apache Tribe
Liquid Hydrocarbon Gravities: Gallup - 44.4° API
Dakota - 48.4° API
Commingled Liquid Hydrocarbon Gravity - 46° API
Commingled gravity on adjacent lease (Jicarilla 22) over a six-month period has averaged 45.3° API.

Value of 44.4° API Crude = $2.35 per barrel
Value of 48.4° API Crude = $2.35 per barrel less $.08 = $2.27
Value of 46° API Crude = $2.35 per barrel less $.02 = $2.33

Anticipated Producing Rates: Gallup - 14 BOPD
Dakota - 8 BOPD

Value Calculations: Gallup 14 BOPD x $2.35 = $32.90
Dakota 8 BOPD x $2.27 = 18.16
Total Separate Value = $50.06/Day
Commingled Value - 22 BOPD x $2.33 = $51.26/Day

The value of the commingled production will not be less than the value of the production from each common source of supply.

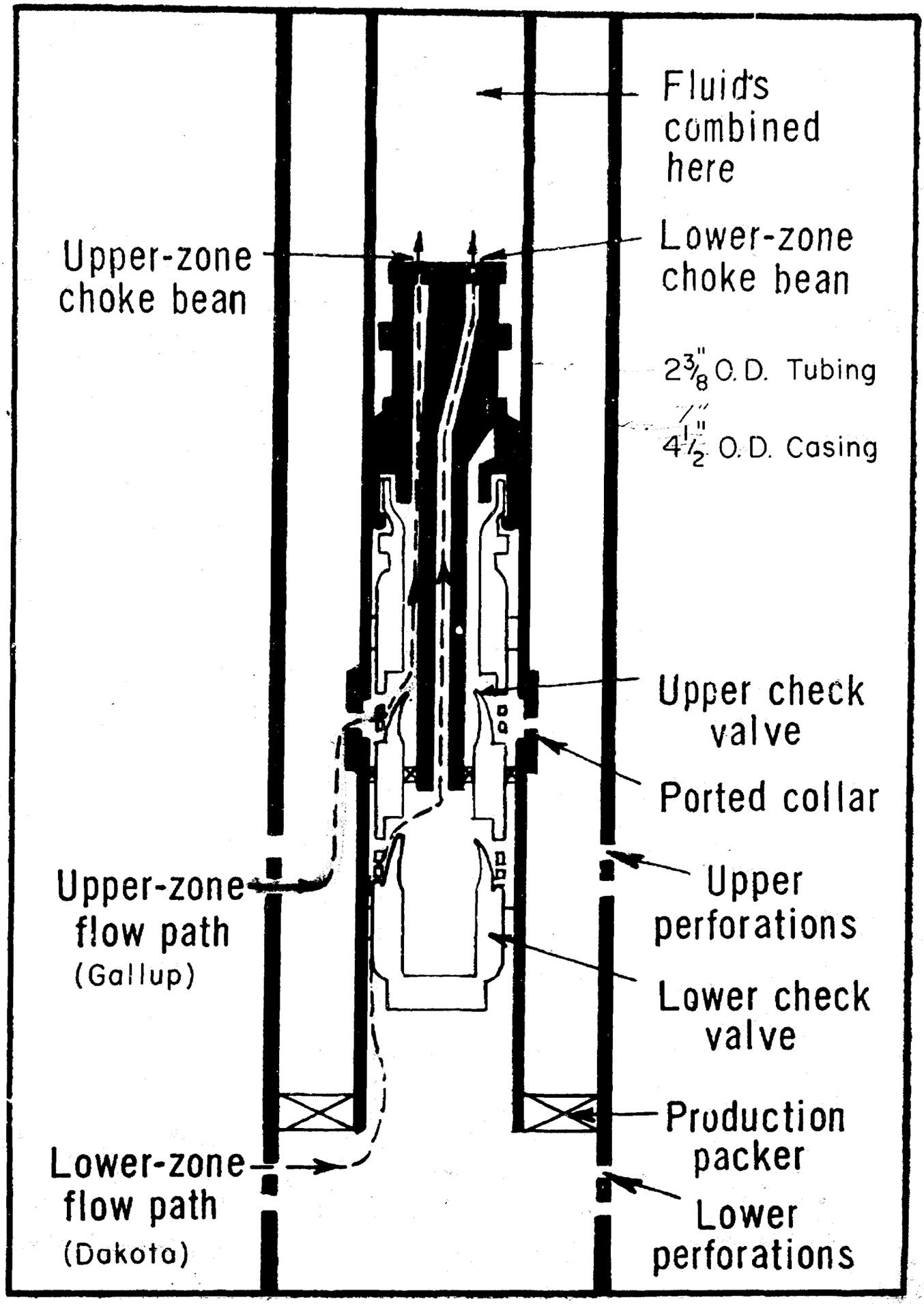
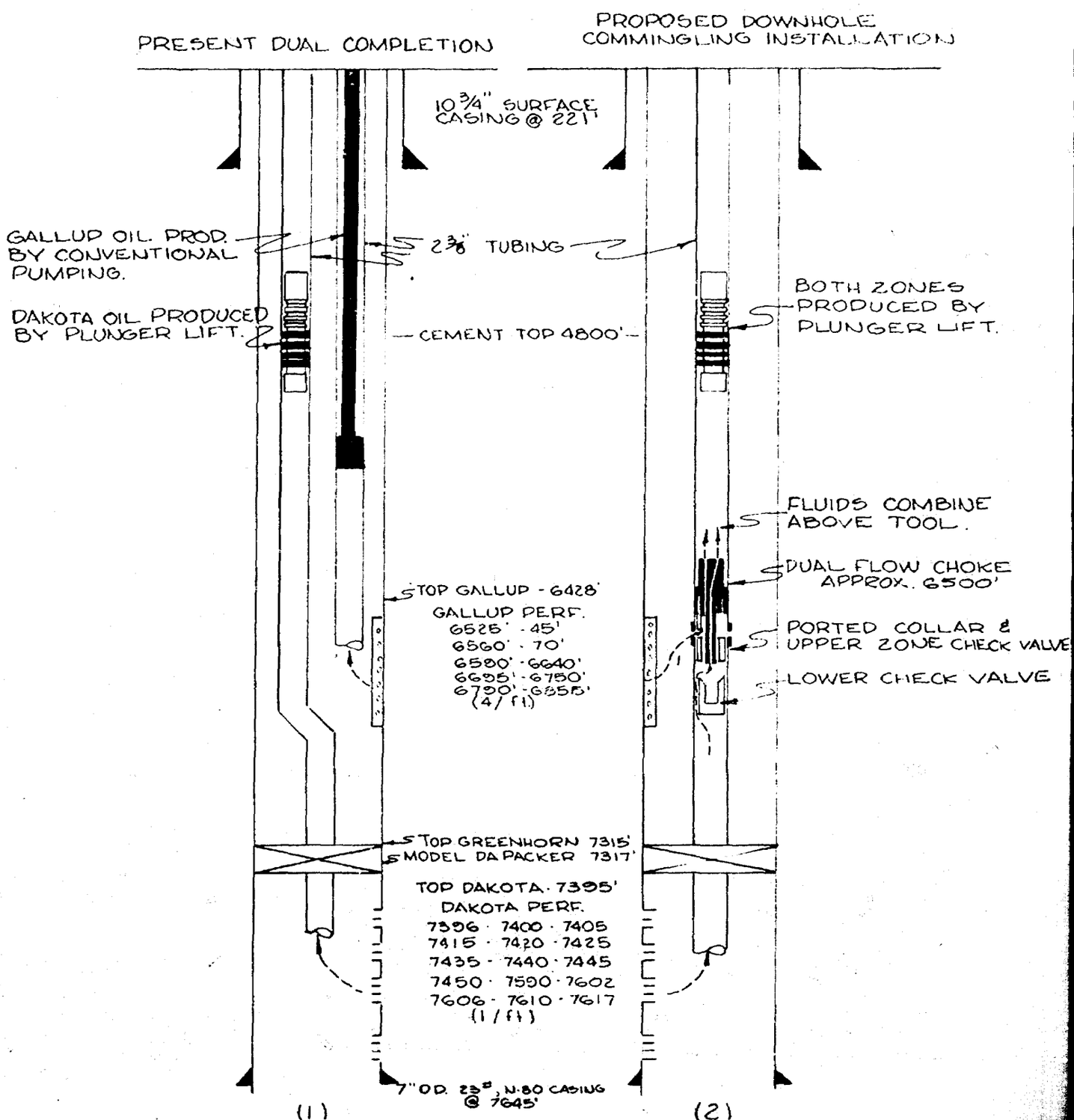


FIGURE NO. 7

Schematic diagram showing installation of Otis "Dual flow choke assembly" for dual zone downhole commingling.

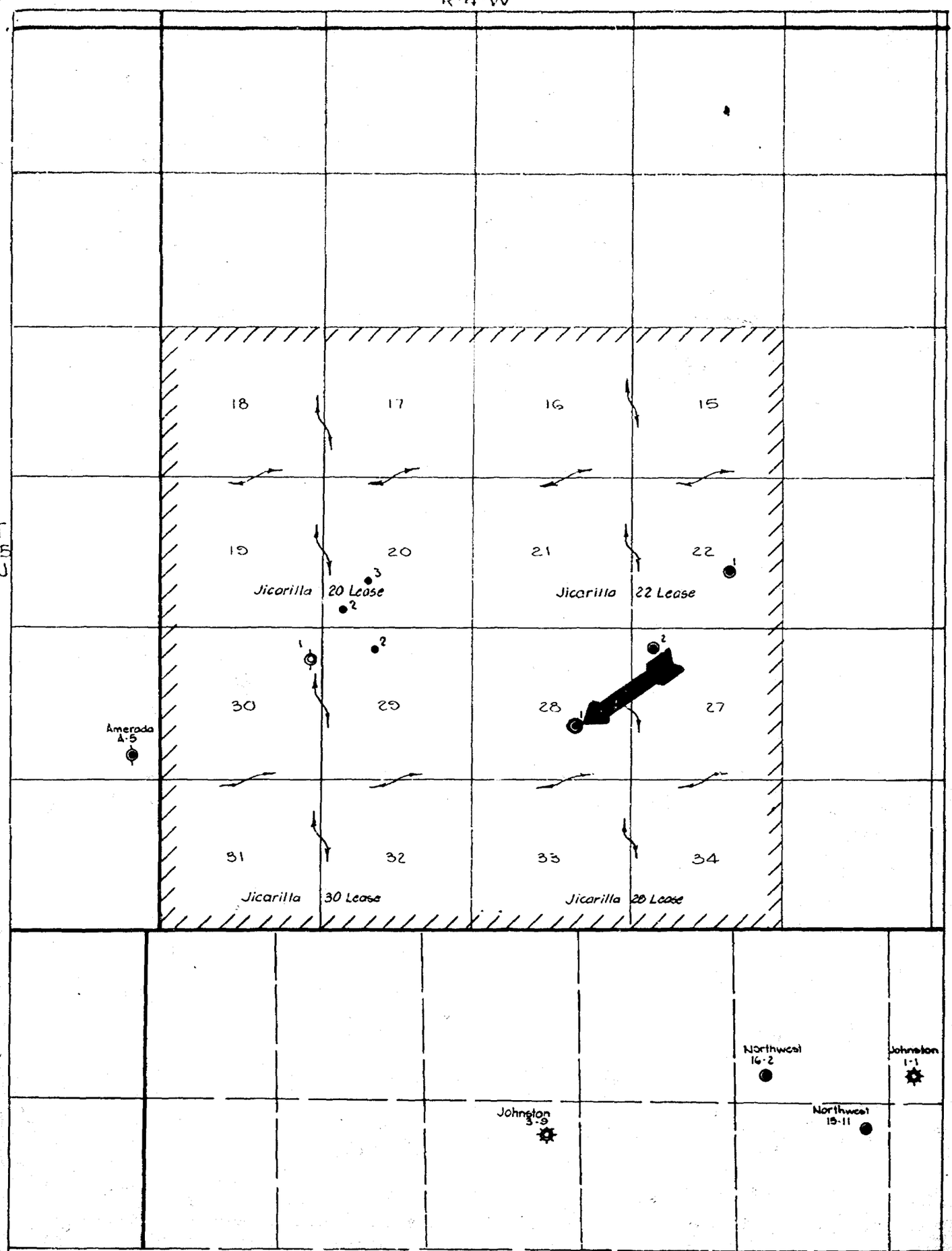
Exh. 3112



JICARILLA 28 WELL NO. 1

SCHEMATIC DIAGRAM SHOWING PRESENT CONVENTIONAL DUAL GALLUP DAKOTA COMPLETION(1) AND PROPOSED INSTALLATION OF "DUAL FLOW CHOKE ASSEMBLY" DUAL ZONE DOWNHOLE COMMINGLING(2).

Case 21h



LEGEND

- GALLUP OIL WELL
- DAKOTA - GALLUP DUAL COMPLETION

CONTINENTAL OIL COMPANY

PRODUCTION DEPARTMENT

DRAWN	SCALE 1" = 4000'	FILE NO.
CHECKED	DATE	
APPROVED	SHEET ____ OF ____	

WEST LINDRITH BLOCK
Rio Arriba Co., New Mexico

Case 3112

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OCTOBER 1961

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

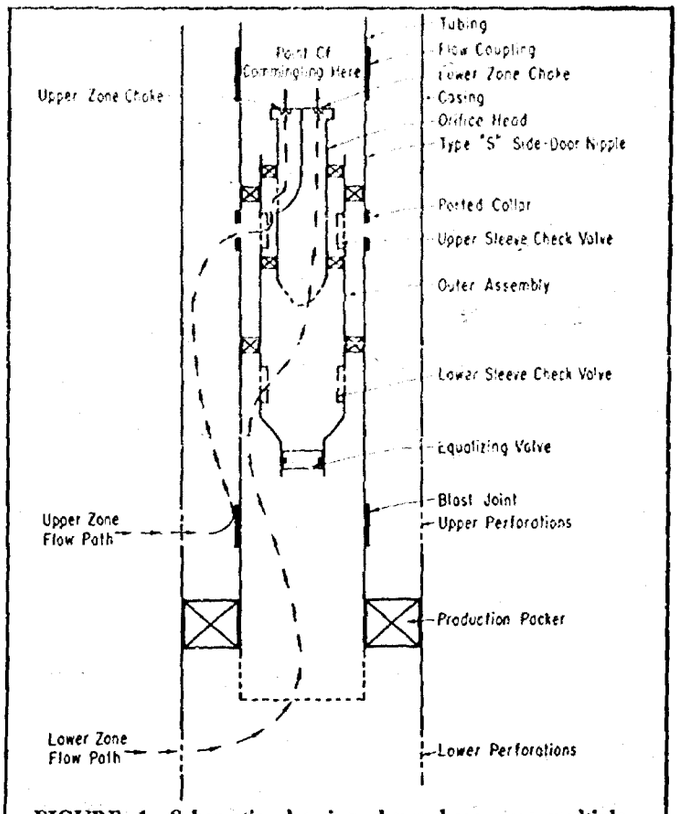


FIGURE 1—Schematic drawing shows how new multiple completion wireline tool works. Note that production is effectively separated until commingled above chokes.

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

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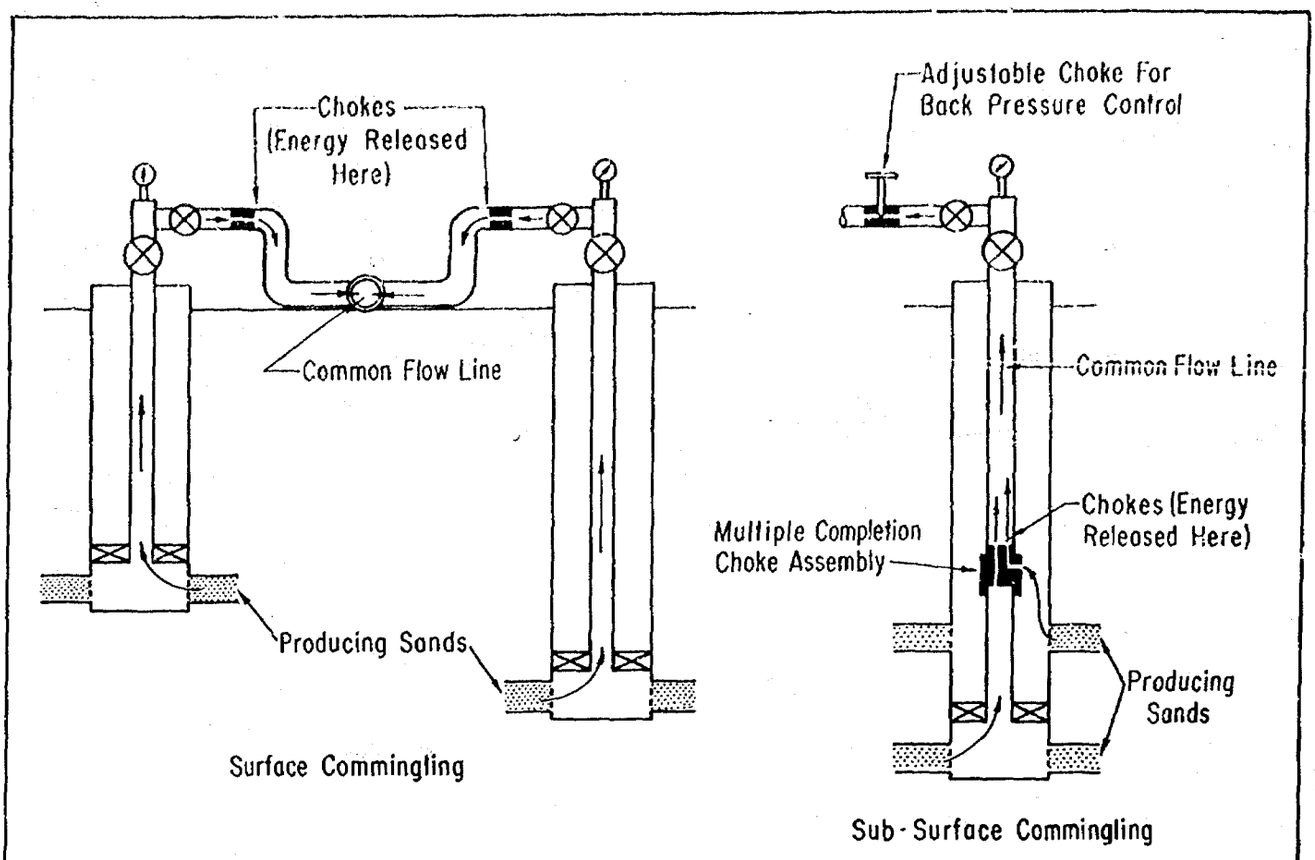


FIGURE 2—Downhole commingling is analoguous to surface commingling except that the pressure reduction is accomplished at the bottom of the hole where energy in released gas can be used.

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 $\frac{5}{64}$-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.

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.

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,

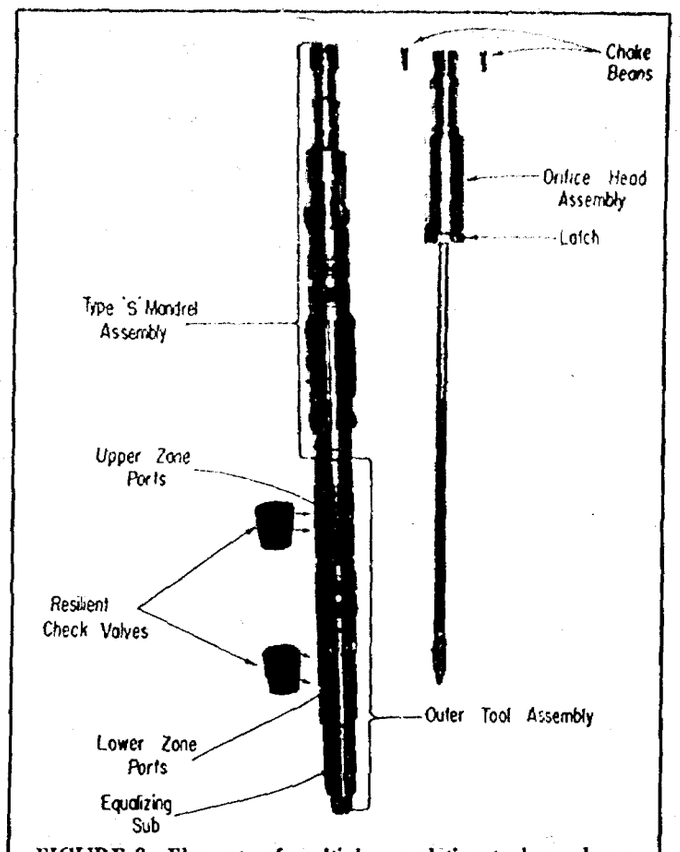


FIGURE 3—Elements of multiple completion tool are shown here. Orifice head assembly can be retrieved separately to blank off one choke for well test purposes or to change production chokes.

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	4-3/64"	6.38	175	27,500

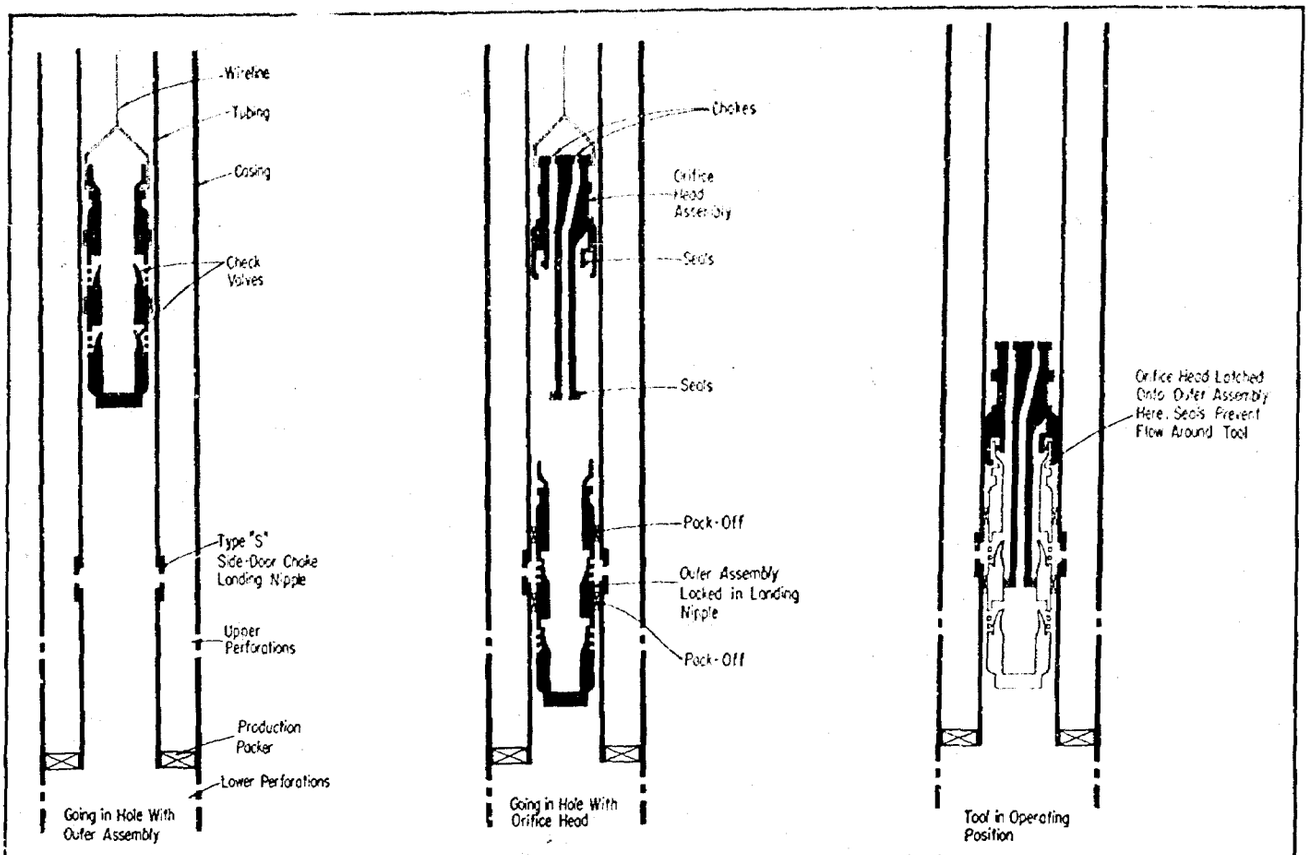


FIGURE 4—Inner and outer assemblies are run separately as shown. Note in center drawing that resilient check valves in outer assembly prevent interzone flow.

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.

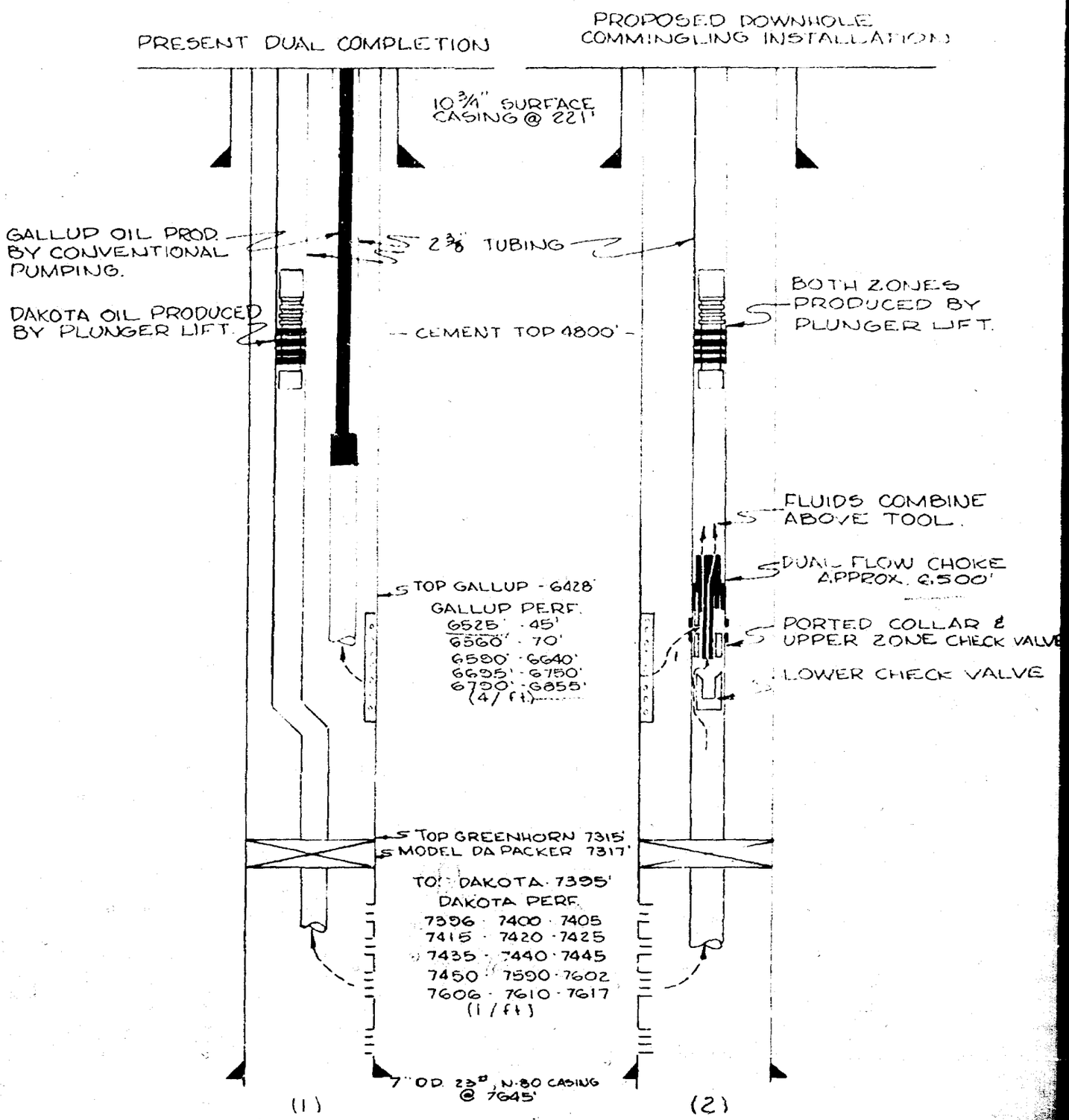


About the Author

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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JICARILLA 28 WELL No 1

SCHEMATIC DIAGRAM SHOWING PRESENT CONVENTIONAL DUAL GALLUP DAKOTA COMPLETION(1) AND PROPOSED INSTALLATION OF "DUAL FLOW CHOKE ASSEMBLY" DUAL ZONE DOWNHOLE COMMINGLING(2).

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BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
September 30, 1964

EXAMINER HEARING

IN THE MATTER OF: Application of Continental Oil Company for downhole commingling, Rio Arriba County, New Mexico. Applicant in the above-styled cause, seeks authority to install dual-flow downhole commingling equipment in its dually completed Jicarilla 28 Well No. 1, located in Unit J of Section 28 Township 25 North, Range 4 West, Rio Arriba County, New Mexico. Said well is a Gallup-Dakota oil-oil dual completion.

Case No. 3112

BEFORE: ELVIS A. UTZ, EXAMINER

TRANSCRIPT OF HEARING

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MR. UTZ: Case 3112.

MR. DURRETT: Application of Continental Oil Company for downhole commingling, Rio Arriba County, New Mexico.

MR. KELLAHIN: If the Examiner please, Jason Kellahin, Kellahin and Fox, Santa Fe, representing the Applicant in association with Mr. Charles Roberts, a member of the Colorado Bar, who will present the case.

MR. ROBERTS: I have two witnesses; I would like to have them sworn at this time.

(Witnesses sworn.)

GEORGE A. BROWN, called as a witness, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. ROBERTS:

Q State your name and address, please.

A George Brown, Durango, Colorado.

Q By whom are you employed?

A Continental Oil Company.

Q In what capacity and how long?

A I have been with Continental five and a half years, and presently Production Engineer in the Production Department.

Q Have you previously testified before this Commission?

A Yes, I have.

MR. ROBERTS: Will the Commission accept Mr. Brown as

an expert witness?

MR. UTZ: Yes, sir.

Q Are you familiar with Continental Oil Company's application on file in this matter?

A Yes.

Q Would you explain the purpose of this application?

A The purpose of this application is presented for approval by the Commission to Continental Oil Company to install a downhole commingling tool on a test basis in an existing Gallup-Dakota dual oil completion well in Rio Arriba County, New Mexico.

The specific well is Jicarilla 28 Well No. 1 located in Unit J, Section 28, Township 25 North, Range 4 West. The primary purpose of the installation and the testing is to try to establish some method whereby further development of this 16-Section West Block can be further developed economically.

(Whereupon, Applicant's Exhibits 1 through 9 marked for identification.)

Q (By Mr. Roberts) Now, Mr. Brown, I hand you what has been marked as Exhibit 1 and ask if this was prepared at your direction and under your supervision?

A Yes, it was.

Q For the record, would you state what is shown by Exhibit 1?

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A Exhibit 1 is a lease plat of the West Lindrith Block which contains 16 sections. It contains four leases, contigous leases, each lease containing four sections. The west well which we will be speaking about is located on the Jicarilla 28 Lease which is outlined in red. All the wells producing from the Gallup and Dakota formations are shown on the plat.

Q Give a brief history of the so-called test well, the 28-1 Well.

A 28-1 Well was completed in June of 1960 as a conventional dual completion, utilizing parallel strings of tubing. This well was drilled to a total depth of 7645, at which point 7-inch O. D. casing was set.

The two zones which the wells are completed in are the Gallup and the Dakota formations, and a Model "D" permanent type production packer was set to isolate the two zones.

As previously stated, the well is a conventional dual oil well which produces through parallel strings of tubing. This dual order on that well was R-1659 Commission Order obtained in May, 1960.

Q Is that the way it is producing now?

A Yes, that is the way it is producing now, through parallel strings of tubing with a Model "D" packer.

The Dakota formation in the well was perforated, and each of the two zones in the Dakota were fracked separately, and

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each zone tested separately; and the well had an I. P. of 137 barrels of oil per day combined from the two zones. This production declined very rapidly the first few months, and the highest average production for the month was 95 barrels of oil from the Dakota. The cumulative production from the Dakota is 25,500 barrels of oil and 170 million cubic feet of gas.

The Dakota presently produces at a rate of approximately 8 barrels of oil per day.

The Gallup, which is the upper formation in the well, was perforated in four separate zones, and the first and second zone and the third and fourth zone were stimulated separately, and the combined potential for the two zones was 170 barrels a day.

The highest production was in July of 1960 when the well made 90 barrels of oil a day for the month.

The Gallup zone also declined very rapidly the first few months and stabilized at a rate in the neighborhood of 20, 25 barrels a day.

The well is presently making 14 barrels a day. Cumulative production from the Gallup zone in the well is 32,134 barrels of oil and 120 million cubic feet of gas.

Q Is the 28-1 Well a top allowable well?

A No, it is not.

Q Is the 28-1 Well physically incapable of producing top

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unit allowable for each zone?

A Yes, it is.

Q Was a log run on this well?

A Yes, sir.

Q I hand you what has been marked as Exhibit 2 and ask you if this is a copy of the log that was run on the 28-1 Well?

A Yes it is, an electroconduction log.

Q I show you what now has been marked as Exhibit 3 and ask you if it was prepared at your direction and under your supervision.

A Yes, it was.

Q Would you please state for the record what is shown by Exhibit 3?

A Exhibit 3 is a compilation of some data that is required for surface commingling installations. Up at the top starting off we have average daily production for 90 day period, at the time this was made up.

In May, 1964 the Gallup zone in the 28-1 Well produced 13 barrels of oil a day, and the Dakota zone produced eight barrels per day. In June the Gallup produced 13 barrels and the Dakota five barrels, and in July the Gallup produced 10 barrels of oil per day and the Dakota eight barrels of oil a day. All production from both zones is below top unit allowable.

Q This is May, June, July of 1964?

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A Yes.

Q What is the gravity of the Gallup and the Dakota production?

A The gravity of the Gallup oil is 44.4 degrees API, and the gravity of the Dakota is 48.4 degrees API gravity.

Q If you were to commingle this production, what would be the commingled gravity?

A At the proportional rates for each zone shown above the approximate gravity of 46 degrees API gravity would be expected. We have a commingling, surface commingling installation on the adjacent lease on the same two zones, and over a six-month period the commingling gravity is averaging 43.5 degrees API.

Q What is the value of the oil from each zone, that is the Dakota and the Gallup?

A The value of the Gallup, 44.4 degree gravity, $2.35 per barrel. The value of the Dakota, 48.4 degree gravity is $2.35 per barrel, less eight cents per barrel penalty for gravity, two cents per barrel for four degrees, which gives a total of all of $2.27.

Q What would be the value of the commingled oil?

A The value of the commingled oil would be $2.35 per barrel, less two cents, or a value of $2.33 per barrel.

Q Would the value of the commingled production be less

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than the value of the production from each common source of supply?

A No, the value would not be less.

Q I don't believe you've stated; do you presently commingle the production from the 28-1 Well?

A No, we do not.

Q What do you do?

A As stated previously, the well has produced through two separate parallel strings of tubing. It produced into separate production equipment at the surface and is stored in separate tank batteries at a site on the lease.

Q I hand you what has been marked for identification as Exhibit 4, and ask if it was prepared at your direction and under your supervision?

A Yes, it was.

Q Would you explain what is shown by Exhibit 4, please?

A Figure 1 on the left side shows the present dual completion method utilized, and which now exists in the 28 No. 1 Well; showing the two parallel strings of tubing and the isolation packer which is set at a depth of 7317 feet, between the two producing zones.

Presently we produce the Dakota by the plunger-lift method of operation, and we have to pump the Gallup zone which cannot be efficiently produced with the plunger-lift.

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On the right hand side, Figure 2 is the proposed method which we would like to obtain approval at this time to commingle downhole. This consists of utilizing the same packer which is now set in the well. One string of tubing, both zones would be produced through a single tubing string, through a commingli tool, or dual-flow choke it's called; and produced by the plunger-lift method of operation; by utilizing the high GOR from the Dakota formation both zones can be efficiently produced by the plunger-lift. This dual-flow choke will permit commingling without communication between the two producing formations.

Q I hand you what has been marked for identification as Exhibit Number 5 and ask if it was prepared at your direction and under your supervision?

A Yes, it was.

Q Would you please explain what is shown by Exhibit 5?

A Exhibit 5 is a schematic diagram showing the installation of the Otis Dual Flow Choke Assembly, or Multi-Completion Tool as it's called, for commingling two zones downhole, two oil zones.

I have shown here the Dakota producing formation in yellow and the path of the upper formation, the Gallup, in orange.

This tool was invented by a genlteman from Sun Oil Company

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and is licensed for sale through Otis Engineering Corporation, and is called a dual-flow choke assembly. This assembly is run in two parts; it consists of two parts, and each part is run independently into the well.

The lower part, which is shown in white, is the check-valve assembly. This assembly, as shown, is run into the well independently and contains a check-valve. It is seated into a landing nipple below a ported collar. Fluid flow is through each individual check-valve; the Gallup flowing through the upper and the Dakota flowing through the lower.

A packing, "V" packing seal directly below the ported collar there prevents communication between the two check-valves assembly while this tool is in the hole by itself.

The upper part of the tool does not have to be in place to prevent communication between the reservoirs, and flow can be made without the upper assembly.

Now, the upper assembly is a choke-bean assembly which contains two choke beans. This is also run into the well independently and landed and locked into the lower assembly.

The packing, as shown at the bottom, just below the ported collar there seals off the production from the lower zone shown in yellow, from entering above that point. Therefore, it is forced to flow up it's respective flow bean to the top of the tool.

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The Gallup enters through it's check-valve and the same "O" Ring and packing here forces the production to come to the top of the tool through it's respective choke bean.

Therefore, commingling does not occur between the two fluids until it has passed through the entire tool and reached the tubing above the tool. At this point above the tool we'll be talking about tubing inlet pressures, and when we do we will be talking about a pressure taken above the tool at this point, a combined pressure of the two flowing zones.

Q Do you propose to measure the monthly production from this test well?

A Yes, we do.

Q How will you do this?

A The production will be measured by an extrapolated tank method at the lease battery.

Q Will you account for production from each zone on a monthly basis as if no commingling were occurring?

A Yes, we will.

Q How will you do this?

A We propose to allocate production back to each of the various zones by two methods during the well test here; to test the validity and see which one of the test methods, the allocation methods will be the best.

The first method will be simply to pull the orifice head

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assembly, the black portion of the tool from the well, and blank off the choke bean for the Gallup side where the orange is shown. The tool will be run back into the well, and with this flow bean blanked off, only one zone will be able to flow, which will be the lower Dakota zone. This zone will be produced, primarily this zone because it can be more efficiently produced with the plunger lift method of operation.

The other zone is not too susceptible to this producing method. A stabilized producing rate will be obtained on the Lower Dakota zone, possibly two or three days, whatever it takes to get a stabilized producing rate. The orifice head part of the tool will then be pulled from the well and the blank taken from the Gallup side of the choke bean, which will allow both zones to flow simultaneously.

The tool will be run back into the hole and again a stabilized producing rate will be obtained for the combined zones. The allocation to the upper zone will be by the subtraction method, subtracting the previously determined producing rate from the Dakota from the combined producing rate obtained on the second production test.

Q Thus leaving you with the Gallup producing rate?

A This will leave the amount of production to be allocated to the Gallup zone.

Q All the while that you are pulling this assembly, this

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portion of the tool, it will not be possible for commingling to occur, as you have previously explained?

A No, the check-valve assembly will remain in the well at all times, and the packing, the "V" packing on the outside of the tool will be between the ported collar and the lower zone and will prevent communication between the two reservoirs.

Q I hand you what has been marked for identification as Exhibit 6, and ask if it was prepared at your direction and under your supervision?

A Yes, it was.

Q Explain what is shown by Exhibit 6.

A Exhibit 6 is a graphical distribution curve which is another method we propose to test for allocating production to the two zones on the test well.

Q This is then the second method of allocation that you mentioned earlier?

A Yes, this is a second method. To continue on explaining what this graph shows; two curves are plotted on the curve by obtaining production and pressure information simultaneously. The upper curve shown in blue, the combined production curve we obtained three, two or three points, whichever are necessary to establish the curve at various producing rates.

The first point up there is 28 barrels a day at a tubing inlet pressure of 700 pounds, and the second is another

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producing rate at a higher pressure, and the third point is a lower producing rate at again a higher tubing inlet pressure; tubing inlet pressure being plotted on the bottom scale, and production in barrels of oil per day on the vertical scale.

Again this tubing inlet pressure is a flowing pressure immediately above the tool. This curve is obtained by having a bottom hole bomb in the well while the well is being produced.

The orifice head assembly, the one in black, again is pulled from the well and either of the two zones blanked off. In our case we would blank off the Gallup zone again because the Dakota formation showing in yellow, can be produced more readily by the plunger method. We would establish this same type of curve off production just coming from the Dakota formation.

This, actually as far as the curve goes, we should say we have blanked off the Dakota and are producing the Gallup, because this is what the curve shows we have done. This curve was just to show the curve. In this case on the curve, Exhibit 6, two points were obtained on the Gallup formation producing at a rate of 14 barrels a day and a rate of eight barrels a day at the tubing inlet pressure of 800 pounds and 1,100 pounds.

At any time, later time when the well is producing, you can go to this curve and obtain just the combined production from the well for any day. Shown in brown, it shows that if the well were producing 20 barrels of oil per day, you could enter

on the production side of the curve, go over to the combined production curve, and at this point this fixes the tubing inlet pressure. That is, at this producing rate the tubing inlet pressure should be 950 pounds. You drop vertically down that line to determine the Gallup production, which would be 11 barrels of oil per day.

By the subtraction method, the 11 barrels of oil per day from the total production, would leave nine barrels of oil per day was produced from the Dakota zone at the tubing inlet pressure fixed at the combined producing rate.

Q How do you propose to insure the validity of the distribution curve method of allocation of production?

A We propose to do this by testing the validity of this curve at least twice during the testing period of six months. We would produce the well with the bomb in the hole and obtain a combined producing rate and another tubing inlet pressure recorded by the bomb. We would enter the curve at the producing rate; in this case here we have shown a validating point of 24 barrels of oil per day, and if the combined producing rate was 24 barrels of oil per day, the tubing inlet pressure, 825 pounds, this point would fall on this curve and validate that the curve is valid.

Q In other words, you would just simply take an actual producing rate and an actual inlet pressure from the well and

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see if that matched up with the point on your graph. If it did then your curves are good, and if they were not, you would adjust your curves. In other words, you would thereby validate the distribution method of allocation of production?

A Yes, I believe it would.

Q Will you also conduct packer leakage tests?

A Yes, we would conduct the packer leakage test as required by the Commission.

Q How would you do this?

A To obtain a packer leakage test we would do it in accordance with the method prescribed by the Commission. We would again pull the orifice head assembly from the well and blank off the Gallup, shown in orange, and run the orifice head assembly back into the well.

We would allow the two zones to stabilize and obtain pressure recordings of the stabilized pressure. We would then produce the Dakota formation up the tubing with no flow coming from the Gallup.

The pressure -- Gallup pressures would be recorded on the casing tubing annulus at the surface with a recording instrument and dead-weight pressures taken.

At the end of the flow period, first flow period, it would not be necessary to pull the orifice head assembly. We would simply shut the well in at the surface, again allow the two

zones to stabilize. After the two zones had stabilized we would produce, or in this case we would flow the Gallup zone up the Gallup casing-tubing annulus at a reduced flowing pressure, and obtain static pressures, record the pressures at the surface on the tubing for the Dakota side, or the lower formation.

If the packer in the well were leaking, and communication between the reservoirs existed, the static pressures taken on both flow tests in the casing-tubing annulus and in the tubing would indicate such a leak.

Q Now, in your capacity of production engineer for Continental Oil Company, have you had occasion to intensively study the West Lindrith Field?

A Yes. I have just recently conducted very intensive study on the economics of the field in the past development.

Q Would you state briefly the history of the West Lindrith Field?

A The first well drilled in the field was in 1959. We have now drilled six wells in the field. We have used four different types of completion methods for the six wells.

The first well, 20 No. 2 was drilled in 1959 and was a single Gallup completion. This well is located in the northwest quarter of Section 29.

The second well drilled was 28-A No. 1 Well, which is the well we're concerned with today. This was the first dual

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completion or multi-completion well in the field; as a conventional dual completion.

The two wells, 28 No. 2 and 22 No. 1, shown in Section 22 and in the northwest quarter of Section 27, were designed for triple completion by running three strings of casing in the hole; two strings of 4 1/2 inch casing, one string of 1 7/8 inch casing, and cementing these three strings of casing in a common hole.

I beg your pardon; I stated previously that the first well was in Section 29. The first well was in the southwest quarter of Section 20.

During 1963 we drilled two more single Gallup completion wells. We completed these wells open hole with a slotted liner; Wells 20 No. 3 and 30 No. 2.

All of the wells drilled in the field were initially high potential wells, relatively high potential wells in both the Gallup and Dakota formation. We stimulated the wells quite heavily; the first four wells were sand fracked heavily with sand-oil fracked treatments, and the last two wells we tried oil squeeze treatments in the open hole section to attempt to increase or stabilize the producing rate from the well by cleaning up the existing fracture system.

As we have stated, all the wells came in from both zones in the neighborhood of 50 to 100 barrels of oil per day.

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within a few months production from the both zones dropped rapidly. The Gallup wells usually levelled off at a rate in the area of 20 to 25 barrels a day, and the Dakota wells from 20 to 15 barrels a day in that area.

Q I hand you what has been marked as Exhibit 7 A and 7 B and ask if they were prepared at your direction and under your supervision?

A Yes, they were.

Q Would you explain briefly what is shown by Exhibits 7 A and 7 B?

A 7 A, I believe, whichever one was stamped there the typical West Lindrith Gallup Well; this is a composite production curve, decline curve, which was established by utilizing five-year production history from four of our wells on the lease, and one Amerada well adjacent to the lease, to establish the type of curve that we could consider as being typical or average for the lease.

I've shown there the actual production from these five wells has been plotted up through the fourth year and the remaining portion of the curve is just predicted. We would expect in any additional development wells, Gallup wells in the reservoir to be typically something in this order here. Some of them, of course, would probably be a little better and some of them would be worse, which is the case we have on the

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existing wells at this time, Gallup wells.

Q But any future Gallup well would be along the lines of 7 A, the typical well?

A Yes, I believe this curve will be representative for a typical well for future development wells, as it is representative of the wells we now have.

Q What about Exhibit 7 B, briefly please?

A Exhibit 7 B is also a composite decline curve for the West Lindrith Dakota. We have used the three wells that we have producing from the Dakota and also some production data on wells just bordering the lease.

This curve again is representative of what the Dakota wells are doing on the lease now in the field, and would be representative for any well we might expect to drill at a future date.

Q In your opinion, what would be the cost to drill and equip an oil well in the West Lindrith Field?

A A single Gallup oil well, equipped with four and a half inch casing we estimate would cost approximately $82,000.00.

Q Have you drilled any single Dakota wells in the West Lindrith?

A No.

Q Do you have an opinion as to what it would cost to drill and equip a Dakota well in the West Lindrith?

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A A single Dakota well with four and a half inch casing would be in the neighborhood of ninety to ninety-five thousand dollars.

Q What would you estimate would be the present cost to drill and equip a conventional dual completion oil well in the Gallup and Dakota reservoirs of the West Lindrith Field?

A A conventional Gallup-Dakota dual oil well would cost us -- with seven and a half inch casing in the well and two strings of tubing, cost, similar, in fact, identical to the type of completion used in the 28"A" No. 1 Well, would cost approximately $128,000.00. This is equipped with pumping equipment and plunger lift equipment as required.

Q In your opinion, would such a conventional dual completion oil well be an attractive economic venture for Continental Oil Company?

A Utilizing this well cost and the typical production history for a future well as determined by the curves in Exhibit 7 A and 7 B, it would not be profitable.

Q What would it take to make such a well as this an attractive economic venture with an adequate rate of return on investment?

A There would be two things you could do, you could reduce well completion and equipment cost, or increase the productivity from the well. We have in all cases in our past

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development tried to increase the productivity of the well to stabilize producing rate by various types of treatment, and we have just been unable to increase the productivity from the well. They all decline rapidly and stabilize at a low producing rate.

Q That leaves one alternative, and what, specifically, did you have in mind with regard to reducing drilling and completion costs?

A We believe by using the downhole or dual-flow choke multi-completion tool in a well we could reduce well costs on a dual Gallup-Dakota oil well.

Q In your opinion will development of the Dakota and Gallup zones be made economically feasible by utilization of downhole commingling equipment in dually completing oil wells in the West Lindrith Field?

A Yes, I do; by utilizing this type of equipment, multi-completion tool, in a well, you could reduce well costs by an estimated $46,000.00 over a conventional dual with two strings of tubing. You could, also, by utilizing the energy from the Dakota to help produce the Gallup zone and produce them simultaneously with the plunger lift, you would save in the neighborhood of two thousand per year in operating cost by eliminating the pumping equipment on the well. Surface equipment and production equipment at the surface would also

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be greatly reduced by commingling the production from the well.

Q Is it your testimony that unless Continental Oil Company can obtain approval to install this downhole commingling equipment in existing and future dual completion oil wells in the West Lindrith, that future development of the Dakota and Gallup reservoirs will be foreclosed?

A Yes, it is my opinion that it would.

Q Based upon your examination of the Otis Tool, and actually your study of the Otis Tool, and based upon your experience in such matters, will this tool permit simultaneous production of two zones in one string of tubing without communication between the two producing zones?

A Yes, sir.

Q In your opinion, will approval of the proposed commingling installation in the test well 28-1 result in convenience and economy to Continental Oil Company?

A Yes, sir.

Q In your opinion, will approval of the proposed commingling installation be in the interest of conservation by permitting the recovery of oil that would otherwise not be recovered from the Gallup and Dakota Pools of the West Lindrith Field, and will approval otherwise prevent waste and protect correlative rights?

A Yes, sir.

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Q Have you obtained any indication of approval from the United States Geological Survey and the Shell Oil Company as crude oil purchaser, of Continental's application?

A Yes, written approval from both parties has been obtained.

Q Are Exhibits 8 and 9 copies of those letters of approval?

A Yes, they are.

Q Do you have a recommendation for the Commission with regard to Continental Oil Company's application?

A Yes, I propose that the Commission approve Continental's application in this matter by granting an exception to Rule 303A and any other applicable Commission Rules that will apply, to permit the installation of the Otis Dual-flow Choke Multi-completion Tool in Continental's dually completed Jicarilla 28 Well No. 1m located in Unit J of Section 28, Township 25 North, Range 4 West, Rio Arriba County, New Mexico.

The installation to be on a test basis for a six-month period from the date of installation. Continental Oil Company will conduct production allocation, packer leakage and communication tests upon installation of the equipment and at 90-day intervals thereafter during the six-month test period.

The tests will be conducted as previously outlined at this hearing. Production allocation tests will be by both the test

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and subtraction method, and verification of the distribution curve method, to determine which is a better method for allocating production.

The results of all the test data obtained will be submitted to the Commission upon the end of each test period for review and comment.

At the conclusion of the six-month test period it is proposed that the Commission, through formal hearing will examine all of the total results and test data from the well and the associated interpretation of the data and consider granting permanent well approval to the Test Well 28 No. 1.

MR. ROBERTS: I would offer into evidence at this time Exhibits 1 through 9.

MR. UTZ: Without objection Exhibits 1 through 9 will be entered into the record of this case.

(Whereupon, Applicant's Exhibits 1 through 9 were entered in evidence.)

MR. ROBERTS: I have no further questions of this witness.

MR. UTZ: Wasn't there an Exhibit 7 A and 7 B included in that string of Exhibits?

MR. ROBERTS: Yes, 1 through 9 and 7 A and 7 B in graphs.

MR. UTZ: The hearing will be recessed until 1:30.

(Whereupon, the hearing was recessed until 1:30 o'clock P. M.).

AFTERNOON SESSION

(Whereupon, the hearing was continued as follows:)

MR. UTZ: The hearing will come to order, please. I believe you had one more question you said?

MR. ROBERTS: Yes, Mr. Examiner.

GEORGE A. BROWN, called as a witness, having been previously duly sworn, was examined and testified further as follows:)

DIRECT EXAMINATION (CONT'D.)

BY MR. ROBERTS:

Q I don't believe this has previously been brought out. Are the working interest, royalty and over-riding royalty interests, commonly owned throughout the lease here involved in this application?

A Yes, in the four-section lease, the 28 Lease which the subject test well is on, and also the other four leases are all commonly owned. They were contiguous and commonly owned by the Jicarilla Apache Tribe.

Q And Continental Oil Company is the working interest owner on it?

A Yes.

Q To make the record clear again, with regard to this

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lease alone, the 28 Jicarilla Lease, it is commonly owned?

A Yes, the area outlined in red on Exhibit 1, the acreage in that lease is commonly owned.

MR. ROBERTS: I believe that's all I have.

MR. UTZ: Any questions of the witness?

CROSS EXAMINATION

BY MR. UTZ:

Q Mr. Brown, how do you propose to take GOR tests?

A Gas-oil ratio tests on the separate zones themselves could be done in the same manner as prescribed as the producing method for allocating production. During this test period, the zone which is flowing could be, will be tested for oil and gas and GOR obtained by the subtraction method.

The GOR of the other zone would have to be periodically tested for GOR, either by the subtraction method from flowing gas produced on the lease which is sold and metered, or on a separate test of the other zone by itself, by blanking off the other zone.

Q Then you would only test one side and use the subtraction method for your total production to arrive at the GOR for the other side?

A Yes, because the gas sold from the lease we should be able to do this. To determine how much gas was produced, we allocated production from the one zone and the remaining part

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part of the gas would be produced from the other zone and could be applied to the allocation, the production allocated to that zone. If the GOR is reasonable and is still on the trend of the GOR this should be sufficient, or we could, as I say, test the two zones individually at certain times to establish what the GORs are in that neighborhood.

Q Do you propose to meter the gas at the surface?

A Yes, sir. All the gas from the well is now and will be sold to the pipeline and is metered by them.

Q What are the GORs for these two formations at the present time?

A The gas-oil ratio of the lower zone, the Dakota, is ten thousand to one. The GOR of the Gallup formation is approximately 6,000 to one.

I have a production curve on the two zones for this specific well, which I don't have enough for exhibits, but I could show you that the GOR trend on the Dakota is 10,000, which is this line here, and has reached as high as 15,000 and as low as approximately 5,000 on the Dakota. It has been pretty stable in that range.

The Gallup, the GOR on the Gallup has increased from 2,000 and it presently is in the range of 6,000, which is this line right here; some above and some below, some five and seven.

Q At the present time it's necessary to pump the Gallup?

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A Yes, it is.

Q So you intend to use this system as a gas-lift project also?

A As a plunger lift. We have one plunger lift installation out there on a couple of low productivity wells. One is a low productivity well, it has been in there quite some time, and a new installation which is in one of the wells, the Gallup wells, which was drilled in 1963, but this, the production from the well, all of the production from the well cannot be produced by the plunger lift, although in some cases it is desirable to maybe get a decrease in production to eliminate some of the operating costs of the pumping equipment. They are in the same range now, fairly close.

Q I would like to discuss with you a little more the packer separation tests or the zone separation tests. I think it might be well to refer to Exhibit 5. I want to be sure I understand just how you propose to do this. As I understand, you will pull the choke bean and put a blank choke in the Gallup side. The reason for this is the Gallup isn't flowing?

A It will flow. It can be produced, but not as efficiently as the Dakota. Another reason we have blanked off that zone is because it is a zone that is in the annulus; that is in the annular area.

Q You'll measure the pressure from the

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shut in Gallup side through the annulus, throwing the Dakota through the tubing?

A Yes, sir.

Q That will be one side of the test?

A Yes, sir.

Q Let's look at the mechanics of this thing, and of course, on that test it is the Gallup pressures that we're interested in, right?

A That is correct.

Q We want to be sure that all your packers and check-valves are subject to Gallup pressure in order to determine whether or not it's leaking Gallup pressure, right? So, since you have the blank choke bean in, the pressure would come through your ported collar, and pressure would be against both your lower seal and your upper seal, is that correct?

A In the Gallup side of the tool you say?

Q Yes.

A It would be against the blank at the top of the choke bean.

Q Yes, through the check valve?

A And stabilize through the check valve and also be pressure against both of the "O" rings on the orifice head assembly and the bean packing on the outside of the check valve as shown there. The pressure would be on both of those points.

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Q We have a seal, I don't exactly see the seal here on your -- Well, I forgot what you call this first part that you put in. What do you call that?

A Check valve assembly.

Q Check valve assembly?

A Yes.

Q There are two sets of packers on that, right?

A No, sir. On the outside between the tubing and the assembly itself is just a "V" packing on the outside. On the inside the little packing shown there is actually the part of the upper assembly which engages at this point.

Q Well, you have a set of chevrons or packers between the chokes, right?

A Yes, sir.

Q That presumably separates the two zones?

A Yes, sir.

Q What is the seal that keeps the Gallup pressure from entering the tubing at this point in the test?

A At this point above this ported collar, you mean, not shown in this area up here, there are no --

Q Packers in that area?

A -- packing shown. Yes, they are, but they are not shown on this schematic diagram. They will be brought out in the tool.

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Q I thought from looking at the tool there is a set of packers up there.

A Yes.

Q In other words, that set of packers will be tested?

A Yes, the pressure will be against this zone and up this way, and also down against this packing here.

Q That would be the only point at which Gallup pressure would be exerted against any of your seals, is that correct?

A Yes, sir, I believe so.

Q After you shut in both zones again I believe it was your recommendation to flow the Gallup zone through the annulus and leave the Dakota zone shut in at the well?

A Yes, sir.

Q Looking at it from the same standpoint as we did a moment ago, and using this time the shut in Dakota pressure, let's follow that pressure pattern and see what seals we're checking on that shut in procedure, the full procedure. The Dakota pressure would flow through your lower check valve, right?

A Yes, sir.

Q And into your tubing?

A Yes, sir.

Q And you'd have static pressure in the tubing, so your pressure would test the other side of the upper seal and your choke valve assembly over your check valve assembly?

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A The pressure in the tubing, the static pressure would be exerted on these packings which are not shown in the upper part of this tool.

Q On your upper packer?

A Yes.

Q Right. And from the bottom you exert pressure on the lower side of your lower packer?

A Yes, on the "V" packing on the outside of the check valve assembly, and the "O" Ring packing on the bottom of the choke bean assembly.

Q Since you have a blank choke on your Gallup side it would not check your Gallup check valve, would it?

A There should be no Dakota pressure at that time against the check valve, no. The pressure should not reach the check valve if the "O" Rings at the top of the orifice assembly are holding.

Q This brings me to the point I don't quite understand, and that's how do you check your check valves?

A The check valve assembly, of course the lower one would be checked during the later flow period on the Dakota, at any time, with or without this tool in the hole when neither zone were blanked off; if you shut the wellhead pressure in and allow both zones to pressure up until the tubing inlet pressure was below the static reservoir pressure, of course the well

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would continue to build up and the zones would flow into the tubing.

Q This is with your choke bean out?

A With both the blank chokes out, yes, sir.

Q All right.

A As the pressure increased above the weaker zone, which in this case would probably be the Gallup zone, this check valve would close and continue to increase, the Dakota check valve would close, if you allow the two zones to stabilize with the choke beans open to flow, there would be pressure then against both of the check valves. Do you see that?

Q Yes, with your assembly under flowing conditions with the well shut in?

A Yes. If communication or a leak in either of the check valves existed, the pressure in the tubing and the pressure in the annulus would tend to stabilize if either one of them were leaking.

Q How much difference in pressure in these two zones do you actually have?

A The Gallup pressure is approximately 2,300, I'm talking about initial reservoir pressures. We have no pressure data on the wells other than those obtained on packer leakage tests. The Gallup, 2,300; the lower zone, the Dakota, was approximately 2,800. Any fluid inside the tubing or the annulus would also

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tend to stabilize through the "U" tube effect.

Q Then under shut in conditions you would, if you had check valve leaks, you would expect the Gallup pressure to be a little higher.

A The lower zone, the Dakota pressure?

Q No, under static condition the lower zone of the Dakota, your Dakota is 2,800 and the Gallup is 2,300. If you had a leak --

A Yes.

Q --you would expect the Gallup pressure to be something higher than the 2,300?

A Yes, or higher than its static pressure.

Q Now, that would check your upper check valve, right?

A Yes, sir.

Q How about the lower one?

A Well, if the lower check valve were leaking I don't believe that would tell us whether the lower check valve is leaking or not, because your higher pressure would be in the tubing, and if it were leaking it would still continue to build up and stabilize at the same pressure, regardless of whether it was leaking or not.

One way you could test this, which we would be glad to do, and should do, probably, is to fill the tubing with fluid, blank off the Gallup portion of the tool there and fill the tubing with

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fluid, your liquid or nitrogen or something, or something of that category, and pressure up down the tubing against the lower Dakota check valve at a pressure which would exceed its bottom hole pressure, and then see if we had a leak back in the formation under those conditions.

Q That would be about the only way you could completely check both check valves and both seals?

A Yes, because if the lower check valve were leaking and the upper one was not, the pressure would continue to build up to the same pressure, yes, sir.

Mr. Tunstall who will talk more on the tool later might have some more different test procedures on this, I don't know.

Q In regard to your Exhibit No. 6, where you've drawn this production curve, are these curves always a straight line?

A No, sir, they are not. Under different wells' conditions, according to either well, you might have two lines which were straight, actually horizontal, if they were in critical flow and you had them choked down to be in critical flow, and the only place where you have the lines that would not be a straight line function are down in the range of a weaker well where you had very little drawdown pressure; then you would have a parabolic curve.

But in this range on this type of well the productivity is very low, and the production wouldn't be read very much closer

anyway, it would almost be a straight line, I'm sure, but where you have very low drawdown pressures.

Q If these were not a straight line would it make any difference in your interpretation of your second formation flow?

A No.

Q The rest of your flow?

A No.

Q If neither your combined curve, or your single formation curve established by test were straight, your third curve, by subtraction, would also be a curved line?

A Would be something different than this. If the curve was valid and could at a later time be proven to be valid by a validation point, it wouldn't make any difference whether it was a straight line or not. As long as you had both curves plotted combined, and one of the other zones and the curves were correct, it wouldn't make any difference on the allocation of production.

Q Incidentally, in your tubing inlet pressure, where is the pressure taken?

A This pressure is taken at a point directly above the orifice head assembly within ten or 15 feet in this area.

Q With a bottom hole pressure bomb?

A With a bottom hole pressure bomb, yes, sir.

Q I note that you have taken a pressure flow point on your

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combined curve here at 12 barrels, is that 12 barrels per day?

A Yes, sir.

Q And at 1200 pounds. Had you taken a flow point, a flow pressure point on your Gallup zone at 1200 pounds, do you think that curve would have been in any different location?

A The Gallup, the red curve?

Q Right.

A No, sir, I don't believe it would have been. If both the curves were parabolic, or either one of them was, it might change a little bit, but as a straight line function here, if you flowed, obtained a producing rate from your lower zone at exactly that tubing inlet pressure by choking at the surface, or whatever manner you had to do it, as long as the tubing inlet pressure was present I believe the point would fall on the red curve.

Q Well, don't different formations have different flow abilities against different pressures?

A Yes, sir, that's true. That is why on here the combined curve is used to get total production, and at that flowing bottom hole pressure for the combined two zones the tubing inlet pressure is fixed; and that is the pressure of the bottom zones after they have been commingled through the choke, and each zone itself might be flowing at a different pressure until after they are combined above the tool and have a common pressure at that

point.

Q But you still don't know for sure, do you, whether the Gallup zone at 1200 pounds tubing inlet pressure would flow six barrels per day?

A No, sir, because as you notice, the points, the tubing inlet points, pressures are different on each curve; because you would, unless you choked the well in some manner such as that to obtain the same inlet tubing pressure on the single zone as you had on the combined zone, it would just be coincidental if the points fell at the same pressure point.

Q That's the whole point of my interrogation. At this point I'm just not real sure, as I presume you are, but I'm not real sure that your subtracted volumes would be correct for the pressure conditions, flowing pressure conditions of your combined stream.

A If the curves are valid.

Q That's the point I'm making. I am questioning whether this red curve would be a valid curve or not, for the subtraction method, since it was taken at a different pressure than your combined stream. In other words, I'm simply questioning as to whether the Gallup formation will flow in accordance with the red curve under the pressure conditions of your combined curve.

A Yes, sir. I don't know of how you could be sure of it,

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just if your curves were valid and this should happen if you had a -- like on a curve, the brown example shown, if you had 20 barrels a day total production at a tubing inlet pressure of 950 pounds, and these two points that were taken on the red curve, that point on the Gallup curve will fall in between here somewhere; this tubing inlet pressure of 950 pounds is somewhere between the two points that we have taken, and you would just have to assume that this curve is correct.

Q I know, but we are prorating oil. We are producing oil against an allowable. We don't want to be making any assumptions in the volume of production, I don't think.

A No, sir.

Q So we want something that we think is correct, so we don't want to make any assumptions. Wouldn't it be better if you established your red curve with the same pressure conditions as your combined production curve; wouldn't that pin it down?

A It would probably pin it down, but I believe it would be just about impossible to get exactly the same pressure.

Q For what reason? You mean your pressure is controlled at your flow beans down here in the hole, or at the surface?

A You would probably have to control it at the surface, and by trial and error go in and see if you were obtaining the same pressure point while the well was producing, normally.

Q Then is it your opinion that you could establish the

two test curves on the same pressure basis?

A Possibly, to get it exactly at the same pressures it would be very difficult. I am sure you could probably adjust your well and through trial and error which would mean that you would have to pull your assembly and put your bomb in the hole.

The bomb has to go in the hole below your plunger lift device and you would have to pull all that stuff, equipment out of the well and run your bomb and flow it with a choke setting at the surface, and pull your bomb and see if this was the same flowing pressure that you had obtained, that you wanted, and if not you would have to change it again. I believe it would just be a trial and error method to establish.

Q How often do you think you would have to establish these curves in order to have an accurate interpretation of the subtracted flow?

A Assuming that the curves -- You mean just run the one point on the combined production?

Q No, to establish your two test curves, how long will the well produce in relation to these two test curves?

A This is something that is just a function of the well, and the 90-day period we would see if the well had changed. If it hadn't, of course, we would take another one in another 90 days; if it hadn't changed we could assumethat the curves were good for 180 days, and continue every two months or so to check

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these curves and if the curve was found not to be valid, we would have to go in and again take pressure points and production points, and plot us new curves, and in the same manner keep validating these curves every 90 days, or whenever the previous curves, the range of the previous curves showed it would last.

Q Is this something that you want to determine on this six months period?

A Yes, on this particular well and these particular formations, we do not know how come we can come up with these type of curves.

We want to try this method out and also the method of actually flowing one zone. At the end of the six-month period the data that we have obtained on both methods will be presented to arrive at which of the methods is the better, and if either are valid for allocation purposes.

Q I believe you said at this time the Gallup would flow?

A Yes, it will flow like on the packer leakage test, if you obtain a stabilized pressure and allow the well to build up, it will flow for a certain period of time. It will not flow continuously, of course. The Dakota the same way, it will flow on test.

Q When you get to the point on this type of installation when one zone will not flow, how are you going to accomplish a packer separation test?

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A Under those conditions you could run a bottom hole bomb, which Mr. Tunstall will go into a little further, which is a unit in conjunction with the orifice head assembly, where you could flow the Gallup, or bring it up the tubing through it's respective choke bean and obtain, with the Dakota blanked off, obtain the actual bottom hole pressure measurement at any time the upper Gallup zone would not flow.

Q Have you had any experience with this type of tool?

A No, sir, I have not.

Q Has your other witness had some experience with this?

A Yes. He has considerable experience and he will go into more detail as to the actual working parts of the tool and some of the various test methods that have been used in the past, which I'm not familiar with, directly familiar with.

Q Now, in regard to your cost figure, I believe you estimated a conventional dual -- Well, how much did this conventional dual, if this is a representative cost, how much did it cost?

A In the neighborhood of $200,000.00, I would imagine.

Q That's not quite representative?

A No, sir, it's not representative. These costs that I have given you are costs that I have developed by tabulating what the drilling costs, the pipe costs, and this is not associated with coring or testing; this subject well had

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considerable testing and coring and such as that, and it was at considerable higher cost.

Q Where does the savings lie in the $46,000.00 difference between this type of completion and your $128,000.00 estimate for your conventional dual? Let's see, a string of tubing, what would that run?

A Approximately -- I haven't had any cost figures on tubing, 2 3/8's inch tubing. Alex, do you have a figure, seventy cents a hundred?

ALEX: Yes. Fifty cents a foot.

MR. UTZ: Fifty cents a foot he said.

Q How much of that do you need?

A Approximately 3,700 foot.

Q Where is the rest of your cost savings?

A Considerable cost will be saved in the installation of 8,000 feet; in this case the total depth of this well is 7,645, between seven inch casing and four and a half inch casing, which we could utilize. I'm talking about future wells now.

Q Yes.

A Which we would utilize.

Q That would amount to a substantial savings, I presume?

A Yes, sir. I sure don't have figures on the cost of the casing, but this is the biggest saving here, one tubing string, and also approximately $10,000.00 in pumping unit

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equipment; which was figured into that total cost, $128,000.00, which comes to approximately $10,000.00.

Q $10,000.00 on the pumping unit?

A For rods, yes. We are talking about one pumping unit, two rod strings, two pumps. Also, there will be considerable saving in dual wellhead costs, and at the surface, there would be some savings on the size of hole you have to drill. The actual drilling cost, with four and a half inch casing, you would be able to drill a smaller hole than if you were putting in seven inch casing. Also, other equipment costs at the surface would be production units, only one production unit would be required, if the production were commingled. We would use heated separators and that type of equipment.

Q I see. Well, some of that could be saved --

A By commingling at the surface.

Q --by metering at, commingling at the surface?

A Yes, sir. Also battery installations and storage facilities, and such as that, which could also be reduced by surface commingling.

The operating costs we feel would be quite substantial, of course we have no figure on it. We can make an estimate at this, but pumping wells at six and seven thousand feet, and with considerable paraffin problems and considerable gas blocking, these are high GOR wells, it's pretty difficult to

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pump then, and the operating costs have been quite high.

Q Let's just use this as a hypothetical case, and I'm sure it's a certainty. The day will come when the Gallup will no longer flow, even with your gas-lift assistance. What do you intend to do at that time?

A At this time we've considered this, and we would possibly later on during the life of the well have to go to pumping equipment on the well, which would be no different than the plunger lift, and, of course, reduce the flowing bottom hole pressure to a minimum by pumping the well down.

Q Then you would pump in the same string of tubing in which you commingled?

A Yes, just the same as the plunger lift operation. The length of time that we can operate on plunger lift, of course, we do not know, and on this well here, which is six years old, five years old, we will get some indication of how it would act, and would give us an indication of how, what kind of a life we could expect for the plunger lift, beyond this five-year period

Q What type of tests do you propose to run during this six-month test period that you requested?

A We propose to run a packer leakage test and production allocation test, by both methods, as I explained; establish the curve average, and also a check-valve communication test, by pressuring up on the well and also just letting the pressure

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build up with the flow beans both open and allocation of production by blanking off one zone and flowing the other zone.

We propose to do this initially upon the initial installation to obtain these tests and develop our curves, and, of course, submit a packer leakage test on completion.

At the end of 90 days we would essentially run the same test, with the exception of probably the packer leakage test; and at the end of the six-month period we would run the packer leakage test, and production allocation test, and the check valve test also.

Q Do you intend to pull the unit at any time during the test, or at the end of the six-month period?

A The complete unit.

Q To physically inspect it?

A At the end of the six-month period we will pull all the equipment from the well to check the packing, the "O" Rings, all of the parts of the tool will be inspected. The check valve assembly itself will not be pulled from the well during the six-month period on any of the tests unless there is an indication of a leak through the packing, or communication test or something like this.

It will be pulled at that time and dressed and rerammed and tests rerun. At the end of the six-month period the entire tool will be pulled from the well and checked over.

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Q Is it your intention to run zone segregation tests after installation of the tool and before you pull it at the end of the test period?

A Yes.

MR. UTZ: Any other questions of the witness?

MR. PORTER: I have one or two.

BY MR. PORTER:

On one of your exhibits here, the one showing the price of the crude oil; is that 7/8ths or is that 8/8ths, $2.35 and $2.70, is that net?

A No, this is gross.

Q That is gross?

A Gross value. We obtained $2.35 as gross from the purchaser.

Q At this time it's on a pipeline?

A Yes, sir.

Q It is my understanding that you are applying for a six months test period --

A Yes, sir.

Q --of this installation, and, of course, the well in question here is marginal in both zones?

A Yes, sir.

Q But in future wells there's a possibility that both, or one or both of the zones might be top allowable?

A In my estimation I don't believe there is a well on this 16 section lease that will vary much from these wells that we have today. We have production south of the lease and production to the west and to the east of the lease, and I believe if you took all the wells in the area you would come up with a decline, typical well curve similar to the one that I have shown you today.

Q But you would be applying for this installation before the well was drilled, so you actually wouldn't know whether it was a top allowable well or not?

A On future wells?

Q Yes.

A I think something like this would be probably on a per well basis, and of course, as such would be subject to being a non-marginal well, I mean a marginal type well, if it were above a marginal well this Commission would probably take different action.

Q In your opinion would that make any difference?

A If the well were top allowable?

Q Top allowable or marginal?

A I believe, I haven't thought about that too much, but I believe with the choke assemblies and the choking of each zone, and to not permit the well to produce above its allowable, which is used in other States which has top allowable wells has

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worked out very well from what I know about them.

Mr. Tunstall, who will speak to you later, I'm sure has a great many examples on top allowable wells; but I haven't studied it too much because we didn't have this condition, and of course, none of the wells produced except on a combined test.

None of the wells we ever drilled out there actually produced above top allowable, and I do not feel it has any on the 16-section block, because the Gallup is confined but quite a bit of production around the Dakota, of course, is erratic, but in the lower half of the block, the lower eight sections of the block, which we feel would be productive in the Dakota, we have wells on both sides at that point, and they would not be top allowable wells in my opinion.

MR. PORTER: That's all the questions I have.

BY MR. UTZ:

Q Was this well in question a top allowable well at any time?

A No, except as a combined rate. By this I mean one zone in the Gallup was fractured and tested by itself, and then another zone was perforated and stimulated and tested by itself. The combined, I think, on one of them was around 170 barrels a day, but upon putting the wells together, why we didn't approach this; no, it is all below 100 barrels a day.

MR. UTZ: Are there any other questions? The witness may be excused.

(Witness excused.)

* * * * * * * * * * *

KARL N. TUNSTALL, called as a witness, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. ROBERTS:

Q State your name and address, please.

A Karl N. Tunstall, 404 Wayne, New Iberia, Louisiana.

Q By whom are you employed, Mr. Tunstall?

A Otis Engineering Corporation in New Iberia.

Q In what capacity?

A Classified as gas tool salesman, but I have been working with the tool for three years and have essentially had control over it, and have dealt with most of the applications on it.

Q Then you have primary responsibility with regard to the tool, which you mean by that, the dual-flow choke assembly by Otis?

A Yes, sir.

Q How long have you been employed by Otis Engineering?

A A period of four years.

Q Do you hold any degrees, Mr. Tunstall?

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A Yes, I have a B. S. Degree in Petroleum Engineering from the University of Southwestern, in Louisiana, Lafayette, Louisiana.

MR. ROBERTS: I would at this time not go into any further qualifications and ask that he be accepted for the purpose of acceptance and application of the tool here.

MR. UTZ: He is qualified to testify in this case.

MR. ROBERTS: Thank you.

Q Do you have a model of the Otis Dual-Flow Choke Multi-Completion Tool.

A Yes, I do.

Q Would you briefly state for the Commission the function or purpose of this tool?

A Well, the basic and primary function of the tool is a means to allocate combined production from the two zones from which they came, and to prevent communication from zone to zone without the orifice-head assembly in place. I guess that covers it.

Q Is this a new tool, as such, new to the Oil Industry, Mr. Tunstall?

A Basically and primarily all the components of the tool arethings that we have used in the past. As far as the packing sections are concerned, the "V" Packing has been in use for some 15 or 20 years.

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The "O"-Ring has been used, not only in this State, but in many others as a means of packing, and there are a few points about the tool that are a little new and different, but basically it is a little old, too.

The check-valve assembly would be one of the new parts and also orifice-head assembly are the new parts of the tool.

Q What name would you attach to this tool in the sense that it has been around the oil industry for some time?

A Tools that you would basically be familiar with in connection with the "V" Packing would be the side-door and the separation tool in your tubing casing duals, where from time to time you would want to cross your annular section over to the tubing and blank your lower zone off; and the plugging portion of the separation tool in itself contains "O"-rings; but most of our positive plugs, or PS Plug, for example, do have the "O"-ring seal in it, and has proven to be a very successful sealing mechanism for positively sealing off communication from one zone to the other.

Q Would you take the model of this multi-completion tool that you have, please, and explain for the Commission its working?

A I would be more than happy to. What I would like to do is, I have a full-size color print of the tool and I would like to add a little color to the session here.

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I would like to lay it out in conjunction with the tool and go through the basic and fundamental parts, if I may.

MR. ROBERTS: I will have no questions from this witness during this portion fo the testimony, so if you gentlemen do, I think it would be better if you just went right ahead and asked.

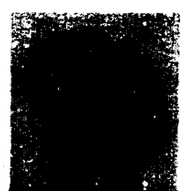
A As an integral part of the tubing string, we run in the blue section, the green section and the purple section. This is actually part of the tubing-string itself.

The blue section is the landing nipple and can be multi-positioned so you can land and locate and pack off. It contains a home section to receive the "V" packing. The ported coupling really allows the upper zone to come in.

The poli-sub, which is the purple section on the outside, is the third portion of the side-soor nipple assembly, and it has a home section in it. It has no locking device in it, but merely receives the packing. It has a predetermined distance between the two packing sections.

The second part of the tool itself is the check-valve assembly, which is run in independent of the third portion, the orifice-head assembly. The check-valve, which you'll see in place here prevents communication from zone to zone at all times, and under all normal routine wireline operations

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would remain in the hole.

The lower zone enters through this check-valve, comes up to this point and with the orifice-head removed, the upper zone would come in and they would both enter the tubing.

Under normal operations we will only put a check-valve on the weaker zone since under most conditions we only need one check-valve, since there is only one weaker zone, and we would not be faced with a problem of zone to zone flow into the stronger zone. In other words, we merely check the weaker zone.

This check-valve assembly had the "V" packing above and below, which isolates the upper zones into the check-valve. This is the only place that it can flow into.

It cannot get past the "V" packing to get above the check-valve assembly, nor can it go back past this set of "V" packing to get with the bottom zone.

The third part of the tool is the orifice-head assembly and when it is run in it is landed and locked onto the check-valve assembly.

It has a double "O"-Ring seal at this point and a double "O"-Ring seal at this point down here in the upper check-valve assembly. This then forces the lower zone to flow in here, it can't go around the "O"-Ring at this point. It must go up the orifice-head assembly, up to one of the choke beans for one

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of the sides.

The annular zone comes in through this check-valve, goes in through the annular area formed by the check-valve assembly and the orifice-head assembly. The prong on the orifice-head assembly comes up and comes around, and flows out the other choke bean.

On this tool we have painted red as the lower and green as the upper. The orifice-head assembly, we have it cut away in sections so that you can follow the flow all the way through the tool. When we run the orifice-head assembly in and it is locked over the running neck of the check-valve assembly. the lower zone which is red, comes in through the red check-valve, cannot get past the "V" packing; the two "O"-rings on the orifice-head assembly to go down the upper check-valve and goes down in it; it forces up the inner, through the red section, coming up the inner tube on the tool, all the way up, and it is still going up the inside of the tube.

At this point it comes out its respective side; at the top commingling takes place, immediately above the tube; the upper zone would come in between the two packing sections at this point, and since the orifice-head assembly has the double "O"-ring seal in the upper check-valve assembly, it cannot go down and get the lower zone.

It is forced up, comes up the orifice-head check-valve

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assembly and it comes up and is shown going through the annular here, and comes out its own side in the orifice-head assembly, and at this point and this point only does commingling take place. The two streams are kept separate throughout their flow course through the tool.

MR. UTZ: How is the check-valve made, is it a metal to metal seal or inner seal?

A I happen to have a check-valve here. What I thought I would do is this. We had a little question that we were going to prompt and force me into if you didn't ask, but I'm glad you did.

The check-valve assembly, this is an actual two-inch check-valve. That's the scale model of the two-inch tool. The drawing is the three-inch tool.

The check-valve assembly itself, the zone flows in and flows around the doughnut area formed by the inside and the outside. It has a double "O" ring seal which means that we not only have a metal to metal seal, when this disc comes down between the "O" rings, but also a metal to rubber seal.

The "O" rings are dove-tailed into a slot which is considered, or called a pressure relief over-ring, so that sudden and instantaneous differentials will not jerk them out of their respective slots. They are recessed back to that in any flow that is occurring they will not have any tendency to

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cut on the "O" ring seal.

With the maximum bean size in the orifice head all areas below the choke bean are at least one and a half times greater than the area of the maximum bean itself, which means if there is any pressure drop at all occurring throughout the tool it will be taken at this point and not through the check-valve itself.

I will say this, that in one instance in South Louisiana, we had a sand problem and an installation with a dual flow choke was put in, we cut the tree off at the surface and we were able to pull and retrieve the check-valve assembly. We found that the check-valve was minutely cut, it probably would not have sealed, but in all other cases, and I can go into several of them, and would like to where we have definite proof that the check-valve assembly has proven an exceptionally fine tool and has never had a history of failure.

In fact, we don't have any history at all, other than this one case where if it's bad enough to cut the tree off at the surface, it's a pretty rough situation to start with.

We, on one occasion in the Belle Isle Field, went in to pull the check-valve assembly in order to take bottom hole pressures below it, which by conventional wireline means we were unable to do. Should the check-valve at that time have been leaking, then we wouldn't have been able to by-pass

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through the check-valve assembly and pull the tool.

By-pass through the tool is affected when we rupture the disc in the three-inch model, or knock a plug out in the two-inch model; otherwise with check-valve assembly in place you have no through by-pass through the tool, unless the check-valve leaks, and in this case we were unable to pull the check-valve assembly.

Also, in the Dallas Plant we conducted a test on the check-valve assembly itself and pumped it for all of one day and overnight and next day pressure tested the check-valve to ten thousand pounds and had a bubble type seal on it.

We had a case, we do have quite a few wireline competitors down in our country, and the competitors not being familiar enough with the tool, did go out and attempt to pull the check-valve assembly for a matter of two days, and it's on an intermittent gas lift well, and extremely low bottom hole pressure, with about a 1,200 foot fluid load was unable to pull the check-valve assembly. The only reason we couldn't was that the check-valve assembly was holding and not allowing any by-pass whatsoever. We were able to go in and get it out once we got the by-pass open.

The history of the check-valve is real fabulous, the check-valve itself and the orifice-head assembly are probably one of the basic reasons why at the present time we are able

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to install and use this tool in the State of Louisiana, Mississippi, Texas and Oklahoma. We prevent communication at all times and also are able to produce and allocate production. I guess I had better quit.

MR. UTZ: Off the record.

(Whereupon, an off the record discussion was held.)

MR. UTZ: Back on the record.

CROSS EXAMINATION

BY MR. UTZ:

Q What happens when you get sand or gravel or some foreign material in this tool?

A Sand or gravel or foreign material under conditions where we do produce sand, even in those instances we have not had a history of failure.

In fact, Texaco's production in the Caillou Island Field is quite a sand producer, and as yet we haven't had any difficulty whatsoever.

I think primarily it is where the pressure drop is taken in those wells up at this point and not down here, so there is no cutting action and the check-valve stays pretty well flushed out.

Q And your velocities down here are lower than they are through this point?

A Yes, where we are faced with a copious sand producer, we do not recommend the use of the tool.

Q And the material in the tool is made out of what?

A The check-valve assembly is heat treated K-Monel. The beans that are placed in the orifice-head assembly are made of 90 percent tungsten-carbide, and has ability to cut glass. The bean sinks in mercury has a high impact resistance.

We have produced a well for better than two years with better than 4000 psi differential across the orifice-head assembly, and a recent gauge, as compared to the initial gauge, was within one and a half percent of the original accuracy, so that we feel that should even the most minute cutting action occur in the bean, then we would have had an immediate response in production, and we haven't had this.

Q In other words, the tool is made of non-corrosive materials?

A Yes, sir.

MR. UTZ: Are there any other questions of the witness?

BY MR. PORTER:

Q How long do you say this particular tool has been in use?

A In Louisiana, the first application was granted in

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March of '60, I believe, so that we have better than a four year history behind the tool.

Q And you say you have installed a tool in Louisiana and Mississippi and Texas and Oklahoma?

A Yes, sir.

Q Would you have any idea how many installations have been made?

A I would assume right now, I will say that at the present time there are about 75 installations that are in and operating, this includes two overseas; but at other times we have had more tools in. In other words, I would imagine there are one hundred installations.

In some cases we have depleted one zone and producing the well, say, as a conventional single without the economic waste of having a dead string tied up; in other installations, where we have deferred the cost of a parallel dual until such time as the well became a chronic sand producer and had to go to a conventional dual. A hundred total, and 75 at the present time.

Q Did you have a hearing in each of these States before you made these installations; was a hearing required in each of these States?

A Yes, sir, in every instance some form of hearing was required. Now, to be more specific, in Louisiana where there

is no difference in royalty owners, at the present time you may obtain your six-months test period on a local application.

At the end of the six-months test period you have a formal hearing and at this formal hearing you must show that you can allocate your production and that there is no communication between the two zones; and if permission is granted, which it has not been denied as yet, you are granted well approval and also in most cases have been granted field approval without further public hearing; but at the same time the regulatory agencies have held the reins back to where you must apply for individual well use of the tool, even though you have field approval without further public hearing.

Q But you might be granted administrative approval without going through a formal hearing, once the testing period is past?

A Yes, sir. Whether or not you, as a Commission, decide to pattern yourselves after the others, or set up your own rules and regulations, I don't want to kick in what they have done, and say that this is a precedent, because you have your own matters of business and ways of conducting it.

Q I was just trying to determine how wide-spread the use had been, and how wide the acceptance of this particular tool had been.

A I will say that in every case so far as we have been

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able to allocate production to the satisfaction of not only the regulatory agency, but the customers, and to our satisfaction and no problem.

Q You say you had a competitor, so I assume there are other manufacturers?

A No, this is in the wireline operation. If I misled you it was unintentional.

Q But no other company makes this particular tool, or one that performs the same function?

A Not actually on the market as such today. I think some of our competition is trying to get out with a tool, and I don't believe we intend to monopolize the market, but at the same time I think with confidence in the product that we're far enough ahead of them to where it will take a long time to catch us.

MR. PORTER: That's all I had.

MR. DURRETT: I have a question, please.

BY MR. DURRETT:

Q Mr. Tunstall, you run this piece of equipment, this machine, down inside two and three-eighths inch tubing, is that correct?

A Yes, sir.

Q That tubing is set in a packer?

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A Yes, sir.

Q So your lower zone production is going to come up, so to speak, through the bottom of this machine --

A Yes, sir.

Q ---through the tubing. What I don't understand right at this stage, is, you have to get that two and three-eights tubing perforated in some manner to get the upper zone in through the side?

A Right. I'll go back to the drawing. The upper zone would flow in at this point. In other words, we would have a continuation of the tubing back down to the lower packer. It has four ports in it and allows the upper zone to flow in at this point, so it comes in at this point.

MR. UTZ: That whole assembly unit is a machine unit on the lower end of your tubing.

Q (By Mr. Durrett) Let me see if I can understand. This piece of equipment is flushed with the two and three-eights inch tubing on the side.

A Yes.

Q You perforated that two and three-eights inch tubing before you run that machine in there, or put a hole in it somewhere?

A Initially this ported collar has four ports in it, four holes in it, and this will receive the side door, the

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separation tool or the dual choke. The side door will be for the production of the lower zone, and the separation tube will be for the production of the upper zone as entities.

Q How do you know when you run the machine down in there that you got that opening just actually where your perforations are?

A From this shoulder here to this point here, where the midpoint of the packing would be is a predetermined distance. Where we are spanning a packer in some installations in South Louisiana and feel that this six-inch polisub will not be adequate, we go to an 18-inch packing sub.

All the distances from this end to this end are predetermined and all measurements are exact and identical. In other words, each piece is machined with a given tolerance, "X" plus or minus 64 in all cases is overall length; 64ths of an inch, so that should we miss the packing section here, even minutely, we would still have the complete and total entity of the packing inside the hole section.

MR. DURRETT: That's what I was interested in. Thank you.

MR. UTZ: The tool actually has a stop mechanism so you can't go clear down through.

A Right, the actual keys locate in the profile of the nipple itself and the reason I didn't go into it further, was

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the fact that it has been used quite often in the State of New Mexico and wasn't anything new; but it could be that I should have gone into it.

The keys are spring loaded, or will locate on this shoulder, under normal producing conditions they will go back up so there will be no sand behind the keys. The dog-switcher right here has a separate recess in which they lock in and the tool is rated for 10,000 pound differential, and has been tested many, many times under conditions that extreme or worse, without failure.

MR. DURRETT: Off the record.

(Whereupon, an off the record discussion was held.)

MR. UTZ: Back on the record. Are there any other questions of the witness?

BY MR. UTZ:

Q What's the usual cost of this wireline operation to retrieve this tool, or pull the choke bean assembly out?

A On a normal 8,000 foot well you would be faced with a four-hour minimum, which would be $62.50. More than likely we could do it in less time, but we got a minimum and that's what you would be faced with as an operator.

Q So to run a packer leakage test it would require a wireline operation?

A Yes, sir.

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Q To run the test in accordance with the procedure set out by Mr. Brown, you would have to go in twice?

A Yes, sir. In the particular installation that we are talking about here, it would probably be a little higher since, at the same time that we go in to pull the orifice-head assembly the piston or plunger lift has a stop mechanism all its own, with a bumper spring attached, that would have to be retrieved first, so this would entail a little bit more wireline time. We were looking at four trips instead of two, double the amount, because we must reset this in order to have a means for the plunger to stop on.

Q So, even though the initial cost of this installation would be less than the conventional dual, the cost of taking the tests would be a little more expensive, by, say, $120.00, because you would have to come out twice?

A Right, but Sun Oil Company took a typical example of a comparison between a conventional dual and the dual flow choke installation, and programmed it over a period of two years, and went back to see just how much, in addition to normal wireline testing, how much wireline fishing could be done on the well, and came up with a figure of $8,300.00 a year, which would be something like $700.00 a month wireline fishing could be done in that period, until the two wells would be exactly the same in total cost at the end of the two years.

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As far as economic savings, they're definitely there.

Q In other words, it is your opinion, I gather, that cost of running these tests should not be enough to cause the operator to come in for a deletion of the packer leakage test, for example?

A Right.

MR. UTZ: Are there any other questions of the witness?

MR. ROBERTS: Yes.

REDIRECT EXAMINATION

BY MR. ROBERTS:

Q To some extent some of my questions will be repetitious, so answer them briefly, but I think the point is well worth making.

You cited several instances where the tool has performed under extreme circumstances, do you have any others in mind that would be of benefit to the Commission than those that you have already mentioned?

A I would like to say at this time that we do have three installations in South Louisiana where we have them on intermittent gas lift and are able to allocate production, and we are using the method as outlined in Exhibit 6, the graphical distribution curve; also on a lot of the wells where extremely low differentials are being taken, due to the

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additional advantage of being able to bring the well to the surface with a higher pressure, and go into sales lines without the compression costs on the gas itself, further promote economic reasons for the use of the tool. We could go into low pressure separator and compress this gas back up, but this is an additional expense that's not necessary. I don't know whether I should at this time go into Exhibit 6.

Q I'd rather not at this time.

A All right.

Q Does this tool have a history of zone to zone communication?

A No, it does not.

Q Permitting zone to zone communication?

A In fact it has, in every instance, it actually prevents communication and has displayed this characteristic in inumerable cases not having zone to zone communication.

MR. UTZ: To supplement his question slightly, how would you compare this in respect to ordinary packers?

A The packing on the tool itself?

Q The Model "E" or any other type of packer?

A The "V" packing would be essentially the same as the packer on a stringer, or the seal assembly in most normal wireline packers. The "O" ring seal, there are quite a few packers of earlier vintage that had the "O" ring seal, and

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was used quite successfully as a means of preventing zone to zone communication.

Your later ones go to "V" packing because it's a little more rugged, but at the same time the "O" ring is a definite and positive seal, and every time the orifice-head assembly is retrieved the "O" rings are changed and you have a new ring, so the seals are done over every time the assembly is rerun.

MR. UTZ: Thank you.

Q (By Mr. Roberts) Now, Mr. Brown touched on this matter, but perhaps we should briefly go into it again.

Would you outline briefly for the Commission the tests that could be used to determine if there is communication between zones?

A To prove, or to proof-test the check-valve assembly we can pull the orifice-head assembly and blank the upper zone, and at that time we will leave the well shut in, and go ahead and build up to some stabilized pressure, both on the casing and the tubing, and at that time we will then open up the tubing and record the change on the annulus. Should no change occur, then we feel this would justify that communication is not occurring from the casing zone back into the tubing zone.

Next, after such test had been conducted we would shut in the tubing below the lower zone to pressure up the tubing to it's maximum pressure and then we would commence to flow the

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annulus, and after having flowed the annulus and observed that there was no change in the pressure on the tubing, we would assume that in both directions every seal, every effective seal had been proven to hold.

MR. UTZ: That doesn't necessarily involve the check-valves?

A No, sir, it would not check the check-valves in any shape or form, since the check-valve would allow the flow to come, and there would be no pressure exerted to the check-valve assembly at this time.

Q (By Mr. Roberts) In those instances where the tool is now being used by operators, do they accurately allocate production by zone?

A Yes, they do.

Q Again, although this was gone into by Mr. Brown, perhaps it would be timely and helpful to the Commission if you would refer to Exhibit 6, and explain what is shown by Exhibit 6, and go completely into detail in that regard.

A In the graphical distribution curve we intend, since this is an example, but essentially does portray what will happen, we will go in and get at least two points, and three if necessary, in order to define the single zone Gallup Curve.

We will more than likely get three points, since there is a chance that it may be a parabolic function. Having once

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defined the curve for the single zone we will get a combined production curve and get three points on it also, and define it's curve.

Then at any time the operator goes out and gauges any production rate into the tank throughout the ranges that we have established the curve, he will then be able to allocate this production back, zone to zone. If at a given day he produced a 20 barrel rate, this would immediately fix the tubing inlet pressure and by entering the curve the pumper would not necessarily need to know what the tubing inlet pressure was, but that he had produced a total of 20 barrels of fluid, and by dropping straight down, this would indicate that 11 barrels had come from the Gallup, and by subtraction, whether the curve for the Dakota were plotted or not, he would know that nine barrels came from the Dakota.

With a day to day variation he could allocate production back, zone to zone from which it came. Sometime during the producing life, in order to insure that the curve is still valid, we will go back in and run a tubing inlet pressure, and gauge the well.

If this point does fall on the curve, then we will assume that the curves are still valid and still an accurate means of allocation.

Should the point fall off the curve at that time, other

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tests would be conducted to establish new graphical distribution curves for the two zones.

If there are any questions about this I'd be happy to go into it, but by getting a validating point on the curve, if any condition whatsoever changed, it would immediately change the curve, whether it be by change in gas-oil ratio, a change in production, either due to producing water, which might not be the case here, or due to a decline in bottom hole pressure, the validating point would not fall on the curve.

Now, the operators, as such, would take action to change and re-establish the curves prior to any notification of the Commission; in other words, say it were a top allowable well and his production fell off below the top allowable, then he would initiate the action to change and get the new distribution curves long before anybody with the Commission would probably have any indication that this had happened, and should he start to produce water, well, then he is immediately going to increase his bean size to allow for this additional production through the bean.

So that other than a cutting action of the bean, which we have no history of, I don't feel that any time you would ever over produce your well.

Q. You would have to determine where your water was coming from?

A Yes, you would.

MR. UTZ: If both zones were producing, then what?

A Then what?

MR. UTZ: Yes.

A We can still go about it by the gross fluid volume. In other words, instead of having three curves on the plot you would end up with five curves on the plot, if you wanted them.

In other words, you could have gross fluid combined, oil combined, gross fluid from the water-cut zone, net oil from the water-cut zone, and by subtracting the curve from the other zone, or if both of them were cutting it, you would end up with a multi-series of curves, but they would still be additive throughout their entire limits.

MR. UTZ: But you would use the same method of determining water production as you do for the oil?

A Yes, sir. We are at the present time doing this in several wells in South Louisiana.

Q (By Mr. Roberts) And there is still another test for determining allocation of production?

A Right.

Q Would you just mention that?

A The direct subtraction method which will be tried during the test period to see if it is valid.

Q You've touched upon this, and it's been previously

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asked, and I think we ought to ask it again, but in using this tool,this dual flow choke assembly, would it matter if the well was marginal or top allowable?

A No, it would not. With reference to communication or reference to the allocation of production?

Q Yes, in it's function and purpose. In your opinion, based upon your experience in such matters, will approval of the proposed commingling in the test well here involved in Continental Oil Company's application result in convenience and economy to Continental Oil Company as operator of the lease involved?

A Very definitely, yes.

Q In your opinion, based upon your experience in such matters, will approval of the proposed commingling installation be in the interest of conservation by permitting the recovery of oil that would not otherwise be recovered, and would it otherwise prevent waste?

A It will do so, and I would like to cite one example. At the present time, as you know, until Belle Isle Field on two occasions, at least two occasions, found a zone, a field sand, and made attempts to produce it, utilizing the dual-flow choke, and in both cases found that the zone was not commercial; in a third such well where it would not have been justified

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for the cost of the parallel dual, due to the prior history obtained on the zone, they did go ahead and for a nominal additional cost, insert the dual-flow choke assembly in the well, and have produced better than $100,000.00 worth of hydrocarbons from the well; and here is one instance where they recovered hydrocarbons that would not normally have been produced, and could not have been economically justified in any other means or method.

MR. ROBERTS: I have no further questions of the witness.

RECROSS EXAMINATION

BY MR. UTZ:

Q Do you have installations where you use this in conjunction with pumping equipment?

A We do not. In pumping equipment, rod pumps we are at the present time discussing and will probably install one with hydraulic pumping in October.

The basic reason at the present time for not using pumping equipment, in other words, a ~~bean~~ beam pump, as such, is the fact that it is quite a costly operation to record the tubing and the pressure underneath the ~~bean~~ beam pump itself. Hydraulic pumps and gas-lift, yes, but ~~bean~~ beam pumping, no.

Maybe at such time when on down the road, guessing a little bit into the future, when we have a means of recording the two

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flowing bottom hole pressures and the two unit pressures back at the surface, and have a continuous recording chart at the surface, then at that time the economics will immediately justify commingling and bean pumping and accurate allocation under any set of conditions, because we will be able to record every bit of information required to do so.

MR. UTZ: Are there any other questions? The witness may be excused.

(Witness excused.)

MR. UTZ: Any statements in this case?

MR. ROBERTS: I would just briefly state, Mr. Examiner, that we respectfully submit that Continental Oil Company has we believe, amply demonstrated here today that the commingling tool is one of unquestionable accuracy and reliability and does the job that it was designed to do, namely, to permit downhole commingling without communication, and permit the accurate allocation of oil by producing zones; and we submit that the approval of Continental's application would be in the best interest of conservation and economy by opening up to development vast amounts of known petroleum reserves in the West Lindrith Field. Thank you for your time and attention.

MR. UTZ: Any other statements?

MR. DURRETT: I would like to ask Mr. Roberts a

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question before we get off the record. I realize that you have stated earlier during a recess, that the machine would be left with the Commission for a short time if we desire.

MR. ROBERTS: Yes.

MR. DURRETT: Do you, or does Otis have some literature, as far as showing the mechanical operation?

MR. ROBERTS: Yes, we do. Thank you for reminding me. We don't have three copies of the diagram that has been put up for illustration purposes, and it hasn't been entered into evidence. I will be more than happy to move for it's admission and leave that with you.

MR. UTZ: I think it might be well to have it in the record then.

(Whereupon, Applicant's Exhibit No. 10 marked for identification.)

MR. ROBERTS: We have had marked as Exhibit 10, a diagram of the multi-completion tool, and I would ask at this time that Exhibit 10 be accepted into evidence.

MR. UTZ: It will be accepted into the record.

(Whereupon, Applicant's Exhibit 10 was admitted in evidence.)

MR. ROBERTS: We will leave you the model as well as the brochures on this.

MR. UTZ: Is there anything further in regard to this case? The case will be taken under advisement.

STATE OF NEW MEXICO)
) ss.
COUNTY OF BERNALILLO)

I, ADA DEARNLEY, Court Reporter, do hereby certify that the foregoing and attached transcript of proceedings before the New Mexico Oil Conservation Commission Examiner at Santa Fe, New Mexico, is a true and correct record to the best of my knowledge, skill and ability.

IN WITNESS WHEREOF I have affixed my hand and notarial seal this 15th day of October, 1964.

Ada Dearnley
Notary Public - Court Reporter

My Commission Expires:
June 19, 1967

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 3112, heard by me on Sept. 30, 1964.

Thos. A. Dick, Examiner
New Mexico Oil Conservation Commission

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NEW MEXICO OIL CONSERVATION COMMISSION

EXAMINER HEARING

SANTA FE, NEW MEXICO

REGISTER

HEARING DATE SEPTEMBER 30, 1964 TIME: 9 A.M.

NAME:	REPRESENTING:	LOCATION:
John D Russell	Texas [illegible] Oil	Roswell
F. B. Morgan	Phillips Pet. Co.	Hobbs
F. A. Watson	Stanolind Prod.	Artesia
Hal Parks	"	"
Marshall [illegible]	[illegible] County	Santa Fe
Ronald J Jacobson	Holly Oil Co.	Tulsa, Okla
George L. Buckles	Self	Monahans, Texas
O. Jack Swan	Amerada Pet. Corp.	Hobbs, N. M.
Jason Kellahin	Kellahin & Fox	Santa Fe
[illegible]	U.S.G.S.	[illegible]
M. B. Jones	Consulting Pet. Eng	Albuq. NM
Karl N. Tunstall	Ohio Oil Co. Corp	New Iberia, La.
S O Mottern	Cities Service Oil Co	Hobbs, N. M.
Charles R Roberts	Continental Oil Co	Denver, Colo.
B. A. Gracian	Continental Oil Co	Denver, Colo.
Fred Von Weiss	Continental Oil Co	Denver, Colo.
A. L. Porter Jr.	[illegible]	[illegible]

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BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
July 28, 1965

EXAMINER HEARING

IN THE MATTER OF: Case 3112 being reopened pursuant to the provisions of Order R-2824, which order authorized Gallup-Dakota commingling in the wellbore by means of a dual flow downhole choke assembly in its Jicarilla 28 Well No. 1 located in Unit J of Section 28, Township 25 North, Range 4 West, Rio Arriba County, New Mexico. All interested parties may appear and show cause why the authority granted under this order should not be terminated.

Case No. 3112

BEFORE: Daniel S. Nutter, Examiner

TRANSCRIPT OF HEARING

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MR. NUTTER: The next case will be Case 3112.

MR. DURRETT: In the matter of Case Number 3112, being reopened, pursuant to the provisions of Order Number R-2824.

MR. KELLAHIN: Jason Kellahin, Kellahin and Fox, Santa Fe, representing the applicant in association with Mr. Charles Roberts, member of the Colorado Bar who will present the case.

MR. ROBERTS: Charles Roberts. If it please the Commission, I have two witnesses I would like to have sworn at this time.

(Witnesses sworn.)

MR. ROBERTS: At the outset, I would ask the Commission to take notice of the record made in this Case 3112, at an Examiner Hearing held here in part on September 30, 1964, together with all of the exhibits which were, I believe, 1 through 9.

MR. NUTTER: We will take notice of the previous record in this case. This is the same case number, just merely reopened.

GEORGE BROWN, called as a witness, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. ROBERTS:

Q Would you state your name and address, please?

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A George Brown, Durango, Colorado.

Q Are you the same George Brown who testified as an expert witness in Case Number 3112, on September 30th, 1964?

A Yes, sir, I am.

MR. ROBERTS: Will the Commission continue to accept Mr. Brown as an expert witness?

MR. NUTTER: Yes, sir.

Q (By Mr. Roberts) Mr. Brown, are you familiar with the Commission's Order Number R-2824 entered in this case on December 7, 1964?

A Yes, sir, I am.

Q With respect to Order Number R-2824, did you personally supervise and participate in the activity authorized by that order?

A I did.

Q Specifically, did Continental Oil Company conduct packer leakage tests for the dual-flow choke after it was installed in the field, to determine annual packer leakage in the assembly and in direction?

A Yes.

Q Did Continental Oil Company also conduct a packer leakage test prior to the installation of the commingling through the 28-1 Well?

A Yes, we did.

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Q And did Continental Oil Company conduct a packer leakage test after drilling that, at the end of six months test period authorized by Order R-2824?

A Yes, sir. At the end of the test period we did run another packer leakage test.

(Whereupon, Exhibits 1, 2 & 3 were marked for identification.)

Q Mr. Brown, I hand you what has been marked as Exhibits 1, 2 and 3, for identification, and ask if these were prepared at your direction and under your supervision?

A Yes.

Q Would you state for the record and the Commission, please, what information is shown on these Exhibits 1, 2 and 3?

A Exhibits 1, 2 and 3 are Northwest New Mexico Packer Leakage test forms. These exhibits are forms completed on the Jicarilla Apache 28 Number 1 well. Exhibit 1 is a packer leakage test taken prior to the installation of the dual-flow choke. This portion of the well was a conventional completion with string and tubing.

On December 17, '64 we shut the well in for the prescribed seven day period, shut-in period, and the well pressure built up on the upper zone to 620 pounds; on the lower zone 1,110 pounds at the end of the seven day period. After the seven day period we produced the upper zone, the Gallup zone flow for period Number 1, and the starting pressure was 310 pounds on the upper

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completion: the lower completion was 1,120 pounds at the end of the test. Forty-eight hours later, on the 26th, pressure on the upper zone was 520 pounds; the pressure on the lower zone had increased to 1,130 pounds. Thereby, this indicates that no leakage occurred in through the cross packer at that point, or in the tubing.

We then shut the well in for seven more days, allowing both zones to build up, whereby the pressure on the upper zone was 705 pounds, built up 705 pounds; and pressure on the lower zone was increased 1,170 pounds. We then flowed the lower zone and the started pressure was 305 pounds. The upper completion pressure data 707 at the end of six hours. The producing pressure on the lower completion increased to 350 pounds, and the upper completion pressure increased to 710 pounds, thereby indicating on the second flow period that no leakage existed. This test was submitted to the Commission and approved on January 20, 1965.

Exhibit Number 2 is the packer leakage test taken immediately after the installation of the Dakota dual-flow choke assembly. We installed the dual-flow choke simply with no blank in the tool and with the lower check valve removed from the tool. The purpose of removing the lower Dakota check valve was that pressure build up and drop in the tubing would not be indicated if there was a leak below this or in

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the packer. We also removed that, had no blank in the tool, so that we could flow the upper zone completion through the annulus and thereby check and prove that the upper check valve was not leaking.

We shut the well in at the end of that time in accordance with the Commission's regulation. We shut the well in for seven days and the upper zone pressure built up to 615 pounds, lower zone 1,185. We then produced the upper zone. The producing pressure dropped to 225 pounds from 615 in the upper; the lower completion pressure increased from 1,185 to 1,195, and indicated that no leakage existed. The lower zone was flowed up the casing annulus.

This test indicated there was no leakage across the packer and also the upper check valve was holding and no leakage occurred across the check valve.

We then shut the well in for another seven days. Both zones built up, to 663 pounds on the upper zone and 1,220 pounds on the lower zone. We then flowed and produced. The lower Dakota zone dropped the pressure from 1,220 down to 350 pounds, and then down to 254 pounds at the end of forty-eight hours. The upper Gallup pressure stayed. 663. 662, 662. taken with the dead weight of the pressure.

This test was submitted to the Commission and approved on February 24, 1965; and indicated that no leakage occurred

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in the packer through the upper check valve assembly of the two.

Exhibit Number 3 is the third packer leakage test taken on 28 Well Number 1, and it was taken at the end of the test period. We again removed the lower check valve for the purpose of the test. On this test we shut in the well for seven days and built up an upper zone pressure of 854 pounds and the lower completion of 855 pounds. We produced the upper Gallup zone up the annulus; again the pressure dropped to 550 pounds. The corresponding lower completion stayed at 806 pounds, continuing to increase five pounds at the end of twenty-four hours. When the pressure on the lower zone dropped -- the upper zone, excuse me, had decreased to 260 pounds and the lower zone pressure continued to increase to 950 pounds, we then shut the well in for another seven days and built up pressure on the upper zone to 774 pounds; the lower zone continued to increase at the end of seven days up to 1,255 pounds. On the lower zone, with the flow period, flow test, we flowed it for a considerable length of time there to allow the Gallup, upper zone to increase, and to obtain working pressure both above and below the corresponding pressure of the upper completion. We note the upper completion started out at 774 pounds, and the lower completion at 1,255 pounds. At the start of the test the first flow pressure on the lower completion was 555;

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the upper completion increased to 300 pounds. We took a few more in between there and the last two. At the end of 96 hours we took one at the lower completion which produced 687 pounds, which is below the pressure of 890 pounds, which the upper completion built up to.

We then drew the pressure down on the lower completion to 255 pounds at the same time, within a few minutes there, and the pressure on the upper completion remained at 890 pounds.

This test was submitted to the Commission and approved on 6-25-'65, and the test indicated no leakage through the packer or through the --

Q Based upon the data obtained by the packer leakage tests which are recorded on Exhibits 1, 2 and 3, and with particular reference to the packer leakage test data obtained from the packer leakage test conducted by the Continental Oil Company on its Jicarilla Apache 28 Well Number 1, was there leakage of the packers and communication between the reservoirs at any time?

A No, there was not. If I may state, on this exhibit, the second page of the exhibit is a direct representation of the pressure data obtained on the packer leakage test.

(Whereupon, Exhibit Number 4, marked for identification.)

Q I hand you what has been marked for identification as Exhibit Number 4, and ask you if it was prepared at your

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direction and under your supervision?

A Yes, it was.

Q For the record, and for the Commission, would you please relate the activities which Continental Oil Company undertook with respect to, or pursuant to the authority granted by Commission Order R-2824, and in doing so would you explain the contents of Exhibit Number 4?

A Exhibit Number 4 is a chronological completion history obtained on the Jicarilla 28 Number 1 Well, during the test period. On the left side of the sheet is a production history. There is a time curve above the curve, at the upper part of the curve it shows the gas-oil ratio; the lower part of the curve is barrels of oil per day. On the left hand side of the sheet, above and between the two curves there, I have a number, starting with Figure 5, Letter A, and marked off in intervals, 1 through 26. On the right-hand side of the page the meaning and the events that took place during each one of these numbered intervals is briefly stated so you can see what we were doing during that interval of time. I have here a figure, which is the same as Exhibit 4, except it's on an expanded scale so it will be a little easier to read.

The letter "A" and the numbers there, and all the information here is the same as it is on here, and the numbers correspond. I have a little bit of additional data on the end

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of this curve, which I had not applied on this curve after June 30th.

Q Basically, what does this show during the interval of the letter "A" here, prior to the installation of the tool?

A It shows the production obtained, tests obtained for about eight days on the well, when it was produced through parallel strings of tubing. The Gallup produced, the Gallup zone here produced approximately 16 barrels per day; the Dakota zone produced approximately 13 barrels per day.

We then started, on January 12th we shut the well in, pulled the tubing , pulled the two strings of tubing from the well, and during the interval shown on Number 1 here, we were releasing one string of tubing in the Model D type Baker permanent packer; and we installed the dual-flow choke to a depth of 660 feet, with the Dakota check valve removed. The check valve was removed for the purpose of taking the first packer leakage test after installation.

We then, during the interval number 2 here, we produced the well, and we haven't shown the production on it. We were recovering load oil used to kill the well; and we finished cleaning up the well and recovered the load oil. At the end of that period we then started on our packer leakage test Number 1, which is actually the second packer leakage test; the second packer leakage test after the installation of the dual

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flow choke; and Number 3 is a shut-in period for packer leakage test Number 1. Number 4 was Flow Period Number 1 on the upper Gallup zone, through the check valve, up the annulus. Number 5 was a second shut-in period, packer leakage.

Number 6 was the flow period on the lower zone up the tubing. And during the flow period indicated in Number 4 here, the upper zone through the annulus, we got 180 MCF per day. Flow period on the Dakota produced 21 barrels per day and had a GOR of 9906.

We then started, during interval Number 7, we pulled the complete tool from the hole and installed the lower check valve; and we blanked the Gallup, or the upper zone off in the tool, and we were now going to try to obtain data for a production graphical distribution curve, which we had submitted in the previous testimony of what we are going to try to do to clear and allocate production.

With the Gallup zone blanked off, we continued to produce from the Dakota to try to obtain a steady stabilized rate at three different back pressures; and all this occurred during Number 7 here. And you can notice the production was very erratic, and this covered the period of a week here; and we never did get the production to stabilize on this low permeable reservoir, and we had not obtained steady stabilized flow or even approached it during seven days.

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During that time, of course, we had pulled the tool. We instalied a bottom hole pressure bomb on a hanger above the tool and below the plunger lift pumper spring; and it was just hanging there on a hanger and would not return for seven days. At the end of the seven days we pulled the pumper spring and removed the bomb, and we came to the conclusion the bomb clock had not operated at all during the period. Apparently going in the hole it had jarred a little bit and the clock mechanism broke and didn't operate. And after seven days here we saw that we weren't going to be able to obtain a stabilized rate in a reasonable period of time. We decided not to go on with that test until we had applied the allocation by the subtraction method, blanking off the other zone.

So, during interval Number 8 shown here, we were -- We put the orifice assembly back in the tool with both zones open and commingled production from both zones. I would like to state right here on, I believe it was February 19th, the production was somewhat below what we would expect from the two zones. From the previous test we had expected about 15 or 16 from the Dakota, and expected about 12 or 13 from the Gallup. This is considerably below; and we bled off the gas to the atmosphere, to take the decreased back pressure on the wells, trying to lower the producing bottom hole pressure of the Dakota zone to the lower pressure of the Gallup zone, with part

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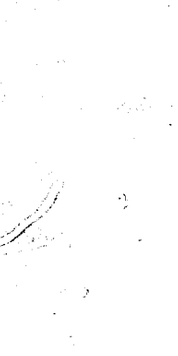
entering the tubing, but it apparently was not entering the tubing at this point. After we decreased the back pressure and drew the bottom hole pressure down, I mean, the upper Gallup zone started producing at this point here.

Both of these zones, of course, are low permeability reservoirs, and after they have been shut in, the accumulation of liquids situated around the wellbore allow the production to be considerably higher than what I remember it was stabilized, which is shown here it was approximately 35 barrels per day; and then it decreased and started leveling off during interval Number 10.

Of course, we continued to produce both zones, and we, at this time we started measuring all the gas produced from the commingled zones; and during the entire period from the 10th through the 12th, both zones were open; and during part of the period of Number 11, and all of Number 12, and we have got this note about Number 13, we felt that this was a good stabilized producing rate for the commingling zones at this point. I have it noted here: "Combined zone stabilized rate at 16 plunger trips daily" as Number 13; and, of course, gas-oil ratio measured during the Period 13 was 6599 for the commingled zones. The average GOR over the 21-day period is 6496; but the entire interval Number 13 was the only one for the allocation.

Period Number 14 we pulled the orifice assembly to blank

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off the upper Gallup zone and produce the lower zone by itself to obtain a stabilized rate and to use in conjunction with the combined zone sobtraction method allocation. On March 25th -- Well, that was March 25th that we removed the tool and everything and installed the blank in the upper zone on the 28th.

During interval Number 15, we started producing what was supposed to be the Dakota zone by itself here, and when we started producing it, well, we thought it was considerably higher than 12-13 barrels that we had anticipated before for the other zone by itself. Because it is typical of the Dakota reservoir, after a shut-in period of four or five days, that we had thought it would produce a higher rate, which it did; so we continued to produce it, and it never did fall down very much below what we had for a combined for a combined rate.

So, about along in this point, Number 16, we started to suspect that the Gallup zone was not blanking off and both zones were still entering the tubing. The blanking off tool is simply a a little disc that fits over one of the orifice openings, and apparently, we thought, it either jarred loose or did not seat itself properly, and we continued to produce it, and it continued to be greater than that known to be the stabilized rate for the Dakota zone only.

At this point right here, at Number -- starting at Number

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18 interval, we drew the well pressure down by bringing the gas to the atmosphere, and when we did this, we noticed that the pressure in the annulus which contained the upper zone, was affected. It did decrease a little bit, and we did this for a couple or three days. We were sure the zone was not blanking off. So, during interval 19 we pulled the upper part of the tool, the orifice assembly, inspected it and found that it had not seated in check assembly. The check assembly had not been removed from the well and was still -- and the check was still holding; so we ordered another orifice assembly and ran it in the hole; and apparently, what we feel had happened, we ran it in vertically and blanked off the lower zone production tube rather than the upper in the previous. We were trying to do this and seat the orifice assembly in the tool, with the other zone blanked off; it was similar to trying to push a piston in a closed cylinder; it just absolutely wouldn't go. For the five inches that has to travel, the fluid wouldn't compress and wouldn't go in. And this has been known, when they tried to do this it would bend the small tube in the orifice head assembly. It was found to be bent, so that is why we ordered another one and replaced it.

We, at this time here we tried to retrieve the check assembly which had never been pulled from the well yet, and was still in the well. In fishing for it we could not get ahold of it, and

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apparently we got it tilted and we were unable to retrieve it after two or three days time fishing, so we had to pull the entire tubing string to get the tool.

At this time we inspected the check assembly real closely and found the check assembly was slightly damaged, not indicating on the tool, and it had just been a matter where we had been unable to seat it properly.

At this time we went back where we were and we installed both the check valve and the orifice head assembly at the surface in the tubing with the Gallup zone blanked off. That was during interval 19. Here we show no production. During interval 20 -- We had to pull the tubing, we had to kill the well, and during the interval 20, as shown by the ledger down here, we produced the load oil during the period, at the end of this period.

Starting period 21, load oil had been recovered and we started other Dakota allocation tests; and as noted here, the production stabilized by ten, three days at ten barrels a day, then dropped to eight for a couple of days and back to ten, down to eight and became stable within a barrel or two. And, of course, we then knew that we had the Gallup zone blanked off, and that this was a representative test to the Dakota zone by itself.

During this period -- Let me go back here for a moment.

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On this combined zone allocation test for both zones, the commingling final nine day average on this period from March 15th to the 24th, from the commingled zone was 25 barrels of oil per day, with a GOR of 6599. The average production from the Dakota zone by itself during the eleven day period here in the interval 21, was 9.3 barrels of oil per day. The GOR was 9216. During the time we did keep our gas production data, and the average GOR, you can see it varied very little. It was 9216, which is considerably above the commingling zone, the Dakota being the higher GOR reservoir.

Being satisfied with this, with the representative test for the Dakota allocation of production, we found we can use the combined zone production, and the Dakota production for subtraction method allocation.

During intervals 22, 23, 24 and 25, we performed the final packer leakage test. At the end of the test period, which is Exhibit Number 3, again we show no leakage through the tool or through the packer, or no leakage in the tubing at the end of the period. Interval 25 we continued, like I stated on Exhibit 3, we continued on the last flow period and got considerable production there, to establish there was no leakage through the packer or check assembly at this time.

The hearing was originally set up to be on June 30th. We had a postponement of the hearing and we continued to produce

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the well with both zones open, and the bottom plug in check assembly in the well, and produced from the commingling. And, as you note, it leveled off fairly good between 25 and 30 barrels a day, which is just as good, if not a little bit better from the two zones producing separately, through single tubing strings, producing the Gallup by conventional pump, and the Dakota by plunger. And, of course, during the interval on complete tests, we used a plunger lift for producing the well. The last four or five days productions are not noted; I hadn't received the information from the field at the time of the hearing.

MR. NUTTER: Now, I can't read those little numbers there. What is the last point, your last day's production?

A Right here, it is 30, approximately 32 barrels per day. Is that the 30 line?

MR. ROBERTS: This is the 30 line right here, yes, sir.

A Right here, it is a little above that, and for a few days above 30.

MR. NUTTER: And it dipped down there to about the 20 line. That would be the 10 line?

A That's the 25 line, that's the 25 line there. There is very little change of production, within three or four barrels there. I don't know whether I have noted here -- Of course, I did the GOR. During the test it was 9216. The average GOR

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during this flow period on the packer leakage test was 8000. See, where the finger is here, the average GOR with the zones commingling over this three week period was 6337, which is very representative according to the combined zone allocation test.

Q So, in summary, during the six-month test period, you conducted three packer leakage tests and found there were no communications, and established, as a matter of fact, there was no communication between the Gallup and the Dakota zones in the 28-1 Well. You undertook production tests at stabilized rates for the purpose of allocating production by the subtraction method. You conducted gas-oil ratio tests and sealed leakage tests, is that correct?

A I would like to go back here on one point; and I didn't stress the point where I did check the seal of the leakage. The seal leakage was obtained during the first shut-in period, or prior to the shut-in period. On the last packer leakage test, what we did there, we loaded the tubing with fluid, both check valves in the assembly, and we had the pressure up to 1500 pounds, and held that pressure for approximately an hour and a half, and at this time there was no indication of any leakage. We recorded the pressure as no indication. The check assembly served as a good seal leakage test.

Q That was by pressure going up the tubing?

A Pressure against the tubing from the surface flow. and

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no leakage was indicated through the check valve.

Q That test, in your opinion, established that there was no seam leakage?

A Conclusively established the test; if we had the pressure, it would not have bled off in that period that we had it shut in.

Q During the course of the six month test period, you, of course, had occasion to examine the commingling tools of the dual flow choke. Did you find any evidence of erosion or corrosion?

A No, none whatsoever on either tool. The only thing was when we fit the orifice head assembly, we blanked open the zone is what happened. No erosion or cutting of the tools.

Q In the hearing on this matter on September 30, 1964, you proposed to allocate production to the established producing zone on the basis of the best of the two possible methods, the distribution curve method and the subtraction method; and you have indicated just a moment ago, that you undertook both methods during the test period. Would you please state your conclusion as to the test suitable in this instance, and why it is suitable?

A The production information shown on Exhibit 4 shows that the production allocation by the subtraction method gives a reasonable and accurate method of allocating production

between the two zones. The other method is, the method, the producing method did not prove out to be satisfactory or suitable on this low productivity, or due to the longer period that would be required to stabilize the wells under the distribution.

(Whereupon, Applicant's Exhibit 5 marked for identification.)

Q I hand you what has been marked for identification as Exhibit Number 5, and ask you if it was prepared at your direction and under your supervision?

A Yes, it certainly was.

Q Would you explain to the Commission and for the record the information shown on Exhibit Number 5?

A Exhibit Number 5 is utilizing the data we have, how we would allocate oil and gas production to this Well 28 Number 1, by the data and information obtained during the subtraction allocation method. This is indicated on the sheet, "Based on the subtraction method allocation test". Oil Allocation, the actual figures obtained during the tests, the ratio obtained. The Dakota production would be 9.3 barrels a day, which was the average Dakota production divided by the 25 barrels a day, which is the commingled production. This factor, times your gross commingled production would give you the Dakota production. The Gallup production equals the gross commingled production minus the Dakota allocated production.

Below there I have an example, a theoretical example,

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utilizing this factor. If you had 750 barrels a day total commingled production; the Dakota allocation was 9.3 divided by 25, times 750 barrels, which would give us an allocation of 278 barrels for the Dakota zone. Gallup allocation would be 750 barrels minus 278 barrels, which equals 472 barrels.

On gas production, on the GORs obtained during the combined commingled and Dakota allocation tests, the commingled GOR was 6599 cubic feet for one; the Dakota GOR was 9216 cubic feet per barrel. Below there I have a theoretical line, theoretical example of how we will allocate production to the gas production to the two zones. If the theoretical gas production under these conditions were used, the 750 barrels per day, plus the GOR would give us the theoretical total of 4949 MCF of gas to produce during that period with the 750 barrels. The Dakota theoretical gas production would be 9216 GOR times the 278 barrels allocated to the DAkota, which would give us a total of 2562 MCF. The theoretical Gallup production would be the difference between the total gas production and the Dakota, which would be 2387 MCF.

Supposedly, say, during the month, one period, you had an actual gas sale of 4635 MCF, and lease use of 450 MCF, you have an actual total gas of 5085 MCF produced during that period. To allocate the Dakota gat to the well, it would take the actual total gas produced times the theoretical factor, GOR

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Factor, of 2562 divided by 4949, which would equal 2629 MCF. This would be the factor obtained from these. The Gallup allocation purports to be the difference between the actual total gas and that allocated to the Dakota, which would be 2456 MCF. This would give the Dakota GOR for that period of 2629 MCF divided by oil production allocation of 278 and would give you 9457. The Gallup GOR would be obtained the same way, you will have a GOR of 5293, which is this line, obtained during the test period.

Q How can the validity of the subtraction method of production between the Gallup and Dakota zone be assured?

A The assurance of the validity of the allocation tests would be obtained by subsequent and periodic, another periodic test on the combined zones and the Dakota zone.

Q Based upon your experience in this instance, within what period of time should such a subsequent test for the purpose of assuring the validity of the production allocation formula be conducted?

A I feel that an annual test of a combined zone test and a lower Dakota zone test to the allocation production, obtained annually, would be sufficient in this very low declining reservoir; both of them are very low declining rates.

Q Based upon the data obtained during the test period, with respect to the Jicarilla 28 Well Number 1, is it your

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opinion, that the subtraction method of production allocation is an accurate and reliable one from an engineering point of view?

A Yes, it is.

Q Are all the wells producing from the Gallup and Dakota reservoirs on Continental Oil Company's acreage, which acreage is shown on Exhibit Number 1 to the September 30, 1964 hearing, marginal wells and physically incapable of producing top unit allowables?

A Yes, they are.

Q Was the Jicarilla 28 Well Number 1 marginal during the test period?

A Decisively so.

(Whereupon, Applicant's Exhibit No. 6 marked for identification.)

Q I hand you what has been marked for identification as Exhibit Number 6, and ask you if it was prepared at your direction and under your supervision?

A Yes, it certainly was.

Q For the record and Commission, please state what is shown by Exhibit Number 6.

A Exhibit 6 is a combined production performance on the Jicarilla 28 Well Number 1, with the Gallup zone pumping and the Dakota zone producing by plunger lift, for a two-year period, 1962 and 1964, prior to the installation of the dualflow

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choke.

The purpose of the curve is to show the well was declining at a very low rate, from both zones; and that with the use of the dual flow choke, and producing both zones through commingling, we obtained production as great as, or a little greater than what we were previous to the installation by producing the two zones separately.

Q In your opinion, is the Jicarilla 28 Well Number 1 typical of existing Gallup on Continental Oil Company's acreage in the West Lindrith Field?

A Yes, it is typical.

Q Do you recall Exhibits 7A and 5B, which were introduced in the hearing of September 30, 1964?

A Yes, I do.

Q Would you briefly explain for the record what those ehxibits show?

A 7A and 5B are composites typical of the Gallup well declining curve, based upon actual data, for a period of about three or four years, obtained from five wells on the lease; and, of course, with the extrapolations determined by what the producing life and characteristics of the well would be. This was utilizing four of our wells and one offset well in the area. This is on the Gallup well.

Exhibit 7B is the same type of curve performance obtained

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utilizing production data on our Dakota wells on the lease for a period of approximately three years, and extrapolating the trend of the well to determine its productive characteristics in life. These curves were utilized primarily in respect to economy evaluation for past and future development.

Q In your opinion, is the information shown on Exhibit 7A and 5B, and as the record should show, these are original -- are the original hearing exhibits, typical of any Gallup-Dakota wells which might be drilled in the future on Continental Oil Company's acreage in its West Lindrith Field?

A Yes, in my opinion, these represent the typical wells for the area.

Q Based upon your knowledge in this matter, is it your opinion, that any such wells that might be drilled on Continental Oil Company's acreage would be marginal wells?

A Yes.

Q Is it your opinion that the subtraction method of allocation of production would be a suitable and proper method for allocating production for existing and for future Gallup-Dakota wells on Continental's acreage in the West Lindrith Field?

A Yes, it is.

Q This has previously been testified to, but perhaps it would be helpful at this time, are the owners of the royalty

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working interest, overriding royalty interest and Continental's acreage common?

A Yes, they are.

Q Do you recall Exhibit 3 which was introduced in the hearing of September 30, 1964?

A Yes, I do.

Q Would you state for the record, very briefly, what is shown by Exhibit Number 3?

A This exhibit was presented in the original hearing as data requirement for surface commingling installation averaged daily, for a period of 90 days prior to that hearing, to show that the Gallup and Dakota zones were both marginal wells, and produced far below top allowable; and the crude purchaser or the royalty owner, on both zones, is the Jicarilla-Apache tribe; what the liquid hydrocarbon from each zone separately was; and the commingled hydrocarbon gravity was; and the value of the gravity crude obtained from each zone separately; and the value of the commingled production in volume calculations; to show that the value of the commingled production would not be less than the sum of the values of the production from each common source of supply. This data is required on all surface commingling installations in the State of New Mexico.

(Whereupon, Applicant's Exhibit 7 marked for identification.)

Q I hand you what has been marked for identification as

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Exhibit Number 7, and ask you if it was prepared at your direction and under your supervision?

A Yes, it was.

Q For the record and the Commission, please state what is shown on Exhibit 7.

A Exhibit 7 is an estimated well cost comparison between a conventional dual flow completion, that is one existing string, with parallel strings of tubing, and a commingled dual installation, utilizing the dual flow check assembly.

The conventional dual well cost is estimated to be around $136,000.00, including surface and production equipment; and for the same well on the commingled dual the costs are estimated at $93,100.00. This indicates a difference here of $43,000.00 between drilling the conventional dual and the commingled dual.

These costs and savings are attributable to such things as casing strings. We could utilize four and a half inch casings with a single tubing string in a commingled dual rather than a seven-inch string. We only need 7,000 feet of tubing string in a commingled dual, to 13,500 feet of tubing in the conventional dual. Other cost savings are attributed to the fact we don't have to utilize pumping equipment; we can efficiently and effectively produce both zones with a plunger lift. Such things as rods and surfave equipment are greatly reduced producing through one set of production tools; and

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in all the difference and savings with the commingled dual was $43,000.00, approximately.

Q In your opinion, would a conventional dual completion oil well in the Gallup-Dakota zone in the West Lindrith Field be an attractive, economic venture for Continental Oil Company?

A No, it would not, in my opinion.

Q Based upon the use of the dual flow choke installation and the reduction of costs which are shown by Exhibit Number 7, and as a result of its use, will the dual completion of a Gallup-Dakota oil well in the West Lindrith Field by means of using the commingling tool be an attractive and economic venture for Continental Oil Company?

A Yes, sir, I certainly believe it would be. I have worked a great deal on economic analyses on this, the two reservoirs in this area, and the typical declining contour that I have previously discussed, this type of typical well for the area, it would require somewhere in the neighborhood of an investment of $40,000.00 in initial cost to make the venture anywhere near attractive, along with the initial well cost of $43,000.00 reduction of other savings, such as operating costs between a plunger lift operation with one string of tubing, rather than producing two wells with conventional pumping units such as this; and also it would be considerably, as indicated by these tests, considerably less down time, with the plunger

lift and a more efficient operation; and these things all lead me to believe that we could and would be able to drill wells in utilizing the downhole dual flow choke assembly on future wells in the Jicarilla.

Q Does Continental Oil Company have any development plans with respect to the West Lindrith Field which are contingent upon its obtaining approval to use this commingling dual in the future wells?

A Yes, we do. We have split our marginal four wells to be drilled during 1965 and produced for 1966; eight additional wells in the sixteen secitons below, for a total of twelve wells. These are, of course, contingent upon approval by the Commission to utilize the dual flow choke assembly, and the economics are based upon well costs utilizing the tool. And, in addition to the twelve wells, we have, the sixteen areas -- the sixteen section leases would just be barely -- just to do development work in future years. There is room for considerable additional development, and additional drilling.

Q You have indicated this already, but perhaps we should ask it directly, does the use of the dual flow choke result in an increase in production rate in respect to the wells?

A Yes, mainly due to their less down-time and average production over any one period, would be considerably more utilizing a plunger lift and dual flow choke assembly.

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Q And does use of the dual result in a greater economic life of the well?

A Yes, it allows the well to be produced for a lower economic limit and would certainly add to ultimate recovery from the wells.

Q Just to summarize then, does the dual flow choke used in the Jicarilla 28 Well Number 1, prevent communication between the Gallup and Dakota zones in that well?

A Yes, sir.

Q In your opinion, did the test you conducted fully and completely prove this?

A Yes, sir.

Q In your opinion, based upon your study and knowledge with the dual flow choke, both prior to and during the six-month period, would this tool absolutely prevent communication between the producing Gallup and Dakota zones on existing and future oil wells on Continental's acreage in the West Lindrith Field?

A Yes, it would.

Q In your opinion, was the subtraction method of allocation for production between the Gallup and the Dakota zones accurate and reliable during the six-month test period?

A Yes, it was.

Q In your opinion, would the subtraction method of allocation of production be the proper method of allocating

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production between the Gallup and Dakota zones in existing and future oil wells on Continental's acreage in the West Lindrith Field?

A Yes, both suitable and reliable.

Q Have you obtained approval of U. S. G. S. and Shell Oil Company as the crude purchaser, with respect to the installation of the downhole commingling dual?

A Yes, sir.

Q Are those Exhibits 8 and 29 to the September 30, 1964 hearing?

A Yes, I believe so.

Q In your opinion, will approval by the Commission of the use of the dual flow choke, which is also known as a fully completion dual, on a permanent basis in the Jicarilla 28 Well Number 1, and in all other Gallup-Dakota oil wells, whether drilled, or which may be drilled on Continental's acreage in the future, be in the interest of conservation by permitting the recovery of oil that would otherwise not be recovered from the Gallup-Dakota wells of Continental Oil Company's West Lindrith acreage?

A Yes.

Q And will approval otherwise prevent waste and protect correlative rights?

A Yes.

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Q Do you have any recommendations for the Commission with regard to this matter?

A Yes, initially, I would like to request and recommend that Continental Oil Company be permitted to continue producing the Jicarilla 28 Well Number 1 with the dual flow choke assembly installed in it until such time as the Commission announces its ruling with respect to the hearing today; and I would also like to request permanent approval of the installation of the dual flow choke assembly in the Jicarillla 28-1 as it has been during the test period.

We would like to recommend that the Commission grant approval to install such a dual flow choke assembly in addition to the commingling oil wells located on its acreage in the West Lindrith Field, and in any Gallup-Dakota oil wells which may be drilled in the future on Continental's acreage in the West Lindrith Field; this acreage being shown on Exhibit 1 of the hearing of September 30, 1964.

And, specifically, that the Commission make provision for administrative approval of future downhole commingling installations by use of the dual flow choke in existing Gallup-Dakota marginal oil wells, and any Gallup-Dakota marginal oil wells which may be drilled within the Continental Oil Company's West Lindrith acreage, which consists of four Jicarilla Apache leases covering Sections 15 through 22 and

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27 through 34, in Township 25 North, Range 4 West, Rio Arriba County, New Mexico.

And, two, that the application for such administrative approval be filed in triplicate with the Commission and such applications contain detailed date as to gravity, value and volume of the liquid-hydrocarbons from each pool, as well as the expected gravity and value of the commingling liquid-hydrocarbon production, a schematic diagram of the proposed installation, a plat showing the location of all wells on applicant's lease, and the pool from which each well is producing; and whether the actual commercial value of the commingled production will be less than the sum of the values of the production from each common source of supply, and if so, how much less.

And, three, that allocation of production to the Gallup and Dakota zones be by the previously discussed subtraction method based on annual production tests of the commingled Gallup-Dakota and the Dakota at stabilized production rates.

And, four, Continental conduct a packer leakage test and seal leakage test upon installation of a dual flow choke in future wells.

Five, that Continental conduct a production test of the commingled Gallup-Dakota and of the Dakota upon installation of the dual flow choke, and annually thereafter.

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Number 6, for Continental to conduct an annual packer leakage test with respect to each well so equipped, in accordance with the New Mexico Oil Conservation Rules and Regulations.

Seven, Continental be granted an exception to Rule 303A and any other applicable rules for the permanent installation of the dual flow choke in Jicarilla Well Number 1, and in any existing Gallup-Dakota marginal oil wells or Gallup-Dakota marginal oil wells which may be drilled on Continental Oil Company's West Lindrith acreage, the location of which I have already described.

Q Do you have any additional comments that you would like to make to the Commission at this time?

A Only that it is my opinion the data presented today in regard to the dual flow choke assembly installation of the Jicarilla 28 Well Number 1 conclusively shows that the dual flow downhole choke assembly can be effectively used to produce commingled hydrocarbons from two separate reservoirs simultaneously through a single tubing string, without communicating between the two zones. The tests show that a leakage does not occur through the check assembly and that annual production allocation tests and packer leakage tests can be satisfactorily performed in accordance with New Mexico Oil Conservation Commission requirements for commingling of marginal zone wells.

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I believe that future tests will show that excess energy from the lower Dakota zone can be effectively utilized to produce the entire weaker Gallup zone which previously required artificial lift by pumping, and by minimizing test requirements, operating costs over conventional dual completion method can be greatly reduced, and the current income from a marginal well such as 28 Well Number 1 can be greatly increased.

By use of the dual flow choke future well costs as previously discussed, can be greatly reduced, and further development of the Dakota reservoir and the Gallup reservoir in the West Lindrith Field would be economically feasible. Use of the tool in this area would also prolong the economic limit of both zones and result in an increase and ultimate recovery from both the reservoirs, thus preventing unnecessary waste and allow recovery of a great deal of oil which would otherwise be left in the ground.

MR. ROBERTS: I have no further questions of this witness.

MR. NUTTER: Are there any questions of the witness?

CROSS EXAMINATION

BY MR. NUTTER:

Q First of all, Mr. Brown, that is your name, isn't it, sir?

A Yes.

Q First of all, I would like to ask you if you would submit your recommendations in writing to us when you get home?

A Yes, sir.

Q We will probably want to study them before we get the transcript back, you see.

A In this respect, I would, at this time, like to request that we be allowed to continue the use of this dual flow choke on Well 28 Number 1 until you reach some decision.

MR. NUTTER: This will be permitted. Secondly, I would like to make the observation, Mr. Brown, among your recommendations there was more or less a blanket authority to permit the use of this, in this same field, on its other locations on these leases, as shown on the original call of hearing. And I was just checking, the original application which is dated August 11, 1964, requests for the purpose of installing the tools in a test well, being the Jicarilla 28 Number 1, and the call of hearing, as you will notice there on your sheet, Mr. Roberts, is for this one well. And the call of this hearing is just to appear and show cause why the authority granted under this order, which was for one well, should not be terminated. And I am not sure that the Commission would have jurisdiction under the call of this hearing, either the original call or the present call, to expand this into more than one well.

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MR. ROBERTS: I think your point is well taken, Mr. Nutter. Now, what we had in mind by this was to approach this matter along the lines that Rule 303A permits, namely, that once you demonstrates it, the workability of and the reliability of such a tool as this, that further use of the tool in the same pool, with respect to the same zones, be approved administratively.

MR. NUTTER: You recommend approving this administratively, and using this means to determine how much was being taken from each pool?

A Yes, sir.

MR. ROBERTS: Yes, sir, that's what we have in mind.

A Along this line, the original hearing, of course, was to install an inter-test well. The express purpose of this being not only to decrease operating costs on this well, the well that has already got seven-inch casing in it and tubing was in the well, but was to test this dual to determine if it would perform to the satisfaction of the Commission and Continental Oil Company; and we felt that these tests could show us whether we could complete other wells in the area, utilizing this tool, and do it economically.

We have undertaken many studies, economical and reservoir devices, to determine if we could do additional development in this area, and all the evaluations showed it couldn't be done

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efficiently if you had a well cost of $136,000.00: and with the high operating cost encountered in pumping high GOR oil wells of 7,000 feet. So, the original hearing, although it was for a test well, the express purpose of it was to determine if the tool could be used to further develop this lease; and to prevent waste by recovering some of these vast reserves that lunderlies the sixteen section block. And we have production all around the area which consistently shows that we are not going to get anymore production from these two than we are getting right here. Most of them on our lease are a little worse than, or some of them considerably worse.

I think for the purpose of our application here today on the show cause order, what we desire immediately, of course, is to continue the use of the steel on a permanent basis in Jicarilla 28 Well Number 1; and as a matter of looking to the future we would seek to handle such matters as this, namely, the utilization of this tool with respect to Continental Oil Company's acreage in the West Lindrith Field, specifically the Gallup-Dakota reservoir, we would seek to handle matters such as this on an administrative basis.

Now, may I repeat this one recommendation which I state as being specific as Number 1: "The Commission make provision for administrative approval of future downhole commingling installations by the use of the dual flow in the existing, and

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future marginal Gallup-Dakota oil wells". We would like to get provisions where we can do it administratively, still giving the Commission the authority to approve or disapprove.

MR. NUTTER: I see.

MR. DURRETT: Let me say at this point, Mr. Examiner, we are up against a legal technicality, as far as the Jicarilla well is concerned. Mr. Roberts agrees, from what he has stated here today, the issue concerns the Jicarilla 28 Well Number 1. There are other legal technicalities present. Let's get together after the hearing and work that out to Continental's satisfaction.

Q (By Mr. Nutter) Now, Mr. Brown, I noticed on your packer leakage test, that in each instance here it's after the Dakota is opened that each one of these Gallup zones has been increasing, it was still building up?

A Yes, sir.

Q And the build up in pressure on the Gallup either discontinued immediately, or was around, on the one test taken, at the end of the test period it continued to build up from approximately 800, well, about 800 pounds, it built up to almost 900 pounds; but prior to the time the Dakota was opened it has been built up at a faster rate; on the other two tests the pressure build-up on the Gallup just discontinued completely?

A Yes, it sure did.

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Q And I wonder if you would attribute this to the exclusive fact of opening up the Dakota, or just what?

A The Dakota is high in gas-oil ratio and, of course, after being shut in there is quick expansion and cooling in the tubing, which I am sure accounts for some of the reduction in pressure build-up; and although if this well typically builds up very fast, because it is a fractured reservoir, during the start of the shut-in period and very quickly levels off, and takes days, months, I don't know how long it would take to completely stabilize this --

Q In the Gallup?

A In the Gallup, because the production fills the fractures immediately, and, of course, pressure builds up. It's -- I forgot to mention the first of the tests, in the first of the statement here, that during the packer leakage test Number 1, we took a bottom hole pressure on the Gallup by fluid level survey in the annulus, and 96 hour shut-in. Of course, we took some periodic tests prior to the 96 hours, it was building up very slowly, only up to 721 pounds; and then, of course, on the Dakota zone, we had the tubing off, we had a pressure bomb in the well, and the bottom hole pressure after 320 hours, built up to 1525 pounds, but the Gallup is typical; in all our present history out there, builds up very quickly during the first, I would say, 24 hours, and very little

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increase in pressure from there on, after the fractures are filled. And, again, the Dakota does give a considerable cooling effect to the pressure during the flow period, and doesn't allow it to build up as much as it probably would in one-fold.

Q Now, though, to what do you attribute the fact, on this most recent test, which was at the end of the test period, that your Gallup had built up to 854 pounds? The pressure on any of these other tests never even came close to that 854 pounds on the Gallup.

A I believe if you will notice there, there is a considerable time difference in the Gallup on shut-in.

Q You indicate it was 33 days. I look at the chart; it shows it was eight hundred and something pounds, and 40 hours back here. I don't know just when this thing built up to 854 pounds. It's not on the chart?

A No, it's not. Of course, this well has been shut in, the Gallup zone was shut in during the complete period of the Dakota allocation test, and we do have a pressure recording on that, continuous for those 33 days, if you would like to see that. During the complete test, both during the production and shut-in periods, pressures were kept on the wells on both zones tubing and annulus during the entire six-month period.

Q Normally, you had been able to get that well up to about 600 pounds, or slightly over?

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A On 168 hours.

Q On 168 hours, 164 hours, you got 620 and 615 pounds, respectively. Do you have the chart there for that 33-day test for shut-in?

A No, I sure don't; just for the seven shut-in period. Of course, I do have them available. I don't have them with me at this time; I could make those available for the Commission on the entire 33 shut-in period.

Q I would like to see those charts, if you have them.

A Yes, I would be glad to submit them. Any pressure information on the tubing, or casing, on either shall be for the entire six-month period and is available. We have every chart on that.

Q Now, after the two zones are commingled in this dual, these two zones flow up through the tubing, is this correct?

A Yes, sir.

Q But normally you would have to pump the Gallup and the Dakota would flow?

A The Dakota would produce by a plunger.

Q By a plunger. Are you using a plunger lift in here now?

A Yes, sir, we are. This is the reason, on the initial test we had to put a bomb on the hanger below the plunger lift and above the tool, the bomb would then be between the tool and

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the plunger spring, which is on a collar, and the plunger would flow freely but would not flow effectively and efficiently without use of the lift.

Q I also notice on your GOR test taken after the tool was installed, after you produced the Gallup you had to produce it up the annulus?

A Yes, sir.

Q And you didn't produce any oil?

A That's true, we had a seven-inch casing and two-inch tubing, and 700 pounds of pressure. It was not enough.

Q Your oil just slipped back?

A Just hasn't got enough reflex there and volume to carry the liquid to the surface, although the pressure can be adequately decreased for the purpose of packer leakage tests.

Q Now, Mr. Brown, do you think that a well which has declined from 13 barrels a day to 9 barrels a day from January to May is a well which is stabilized enough so that you can allocate production on tests taken only once a year? Percentagewise that's quite a large change in the productivity.

A Yes, the test obtained on the Dakota during that first period shown as Number A there, the 13 barrels a day; the Dakota had been shut in previous to that, and has shown on the other test, after the shut-in period, it produced quite high; so we do have a few days highs in there.

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This was not a stabilized rate at 13 barrels, this was just an average for those seven days. We had some 15 barrel days, and some 8 or 9 barrel days, but as you will notice, I don't have it here, production from the Dakota zone over the past two years are approximately 10 barrels per day, 10 or 11.

Q Now, your original Exhibit 3 has some figures. Were these the figures on this particular well, or were they average figures for the Dakota wells?

A Probably taken from our composite curve there at the end of the area, just a ratio, which I believe the ratio is probably close to what we came up with there. I don't remember what figures they were, but they were not actual figures from this specific well.

Q Now, if these figures are correct, using the 9.3 for the average daily Dakota production and taking the production on this new data that you have here, which isn't on Exhibit 4, but taking it from the 1st day of July on to the end, that would be an average combined production of 29.5 barrels per day?

A Yes.

Q So your Gallup is actually producing in excess of 20 barrels per day at this time then?

A No, sir. Your ratio would be the same, I believe.

Q Your Dakota is producing a little more than your

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Gallup is producing?

A A little more, I don't know how much with the plunger operating, but it's operating at optimum cycles on this specific well; and the adjustment in time may be an hour to the surface flowing with the plunger coming up, or an hour and ten minutes maybe. We might decrease it to an hour, I mean to forty minutes and it's sort of an art to get a plunger lift operating efficiently.

Well, the pumper out here is trying to get it producing efficiently, and has been taking real close care of it to show us during the last two or three weeks that we can produce it effectively, and should market around, we can get at least 25 or 30 barrels a day. We are paying pretty close attention to it, and it is, like I say, sort of an art to get that thing working, and it takes a lot of practice to get it operating efficiently, and it does take some playing with.

Q Now, if the well is producing in excess of 9.3 barrels why would you use 9.3 for your allocation and subtraction?

A Well, these two test the allocation for the combined and the Dakota test, we tried to keep the producing characteristics and operating characteristics of the plunger lift and everything pretty much the same here. We needed to know more than we did to try to get the well stabilized, if it was going there along there open, and with the pump operating,

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you might get up to 27 or 28, so we kept it there at that point, and the same point characteristics as on the Dakota test, so we ended up with a ratio rather than a figure for the two zones.

In other words, if we produce during the month, 3 or 4 barrels of oil per day, the same ratio would apply, and I believe would be correct, if the well was producing a little more efficiently, and level off at a good efficient rate, and we would get more production than the 9.3 for the Dakota, and a little more for the Gallup, which we would come out a little over 16 barrels per day on the per well, day per day basis according to the facts that we had obtained during the allocation. And I believe this factor would hold true and would be reasonably reliable as far as allocation of a marginal zone for a period of a year.

We have discussed this period, we have requested this period of one year because we strictly believe if we have a plunger lift in the well we have to run any kind of a well in an attempt to blank off the zone and if we are required to get a wire line service company out there to pull out the plunger lift we have in the well --

Q And maybe end up pulling the tubing like you did the last time?

A Yes, possibly, but we have to put it back in there

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to produce it, and unblank it; if you have to pull everything out of there again, this cost runs two or three hundred dollars every time you even try to pull a well -- pull the equipment one time.

Q This is just for the equipment stops to pull the blank and put them back?

A Right, you are hooked for $200.00, in that neighborhood, any time you run that kind of a test, and cost-wise, economically, you can't run too many tests of this type on it.

Q Now, Mr. Brown, you have requested this because these are low marginal wells, and your Commission dictated that you have to keep your operating and your completion costs down. What would happen in the event -- Now, I notice that you are using four and a half inch casing, what would happen in the event that you drilled a well and completed it with four and a half inch casing and it turned out that it wasn't a low marginal? You wouldn't propose to use this type of system to allocate among good wells, would you?

A Top allowable you mean?

Q Yes, sir.

A On our recommendation here, we have specifically asked on future marginal oil dual Gallup to include completion. We wouldn't expect the Commission to use the same reasoning or

same policies to govern a top allowable well, although if it were a flowing well and approved, in other situations, that allocation can be done through the distribution basis, and on a reliable basis; but as far as our requests are that the best marginal oil Gallup dual completion be used.

Q Have you made any dual completions yet with four and a half inch casing?

A No, we haven't, just single completion. We have two wells out there which are equipped with, comprised of two strings of four and a half and one string of two and seven-eighths casinghead in a common wellbore; that is why we have requested the authority on future and existing wells to reduce operating costs. You might want to take one of those four and a half inch casings and produce the well as one single.

Q In other words, produce the four and a half in one zone and abandon the other?

A Abandon the other.

Q This would give you the ease of artificial lift?

A Some of those that are Gallup wells, of course all of them are marginal, six or eight barrels a day. They have to pumped, and of course, at or very near their economic limit at the high operating cost.

Q Do you have anything else?

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A No.

MR. NUTTER: Any questions of this witness? If there are no further questions the witness may be excused.

(Witness excused.)

* * * * * * * *

CARL TUNSTAHL, called as a witness, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. ROBERTS:

Q State your name and address and by whom employed and what position, please?

A Carl Tunstahl, New Iberia, Louisiana, employed by Otis Engineering Corporation as Gas Tool Salesman, and have since the first been working on a dual flow check for Continental Oil Company.

Q Mr. Tunstahl, what is your educational background?

A I have a Bachelor of Science Degree in Petroleum Engineering from the University of Southwest Louisiana, Lafayette, Indiana.

Q Are you the same Carl Tunstahl that testified as an expert witness in this Case Number 3112 on September 30, 1964?

A Yes, I am.

MR. ROBERTS: Will the Commission continue to accept Mr. Tunstahl as an expert witness?

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MR. NUTTER: Yes, sir.

Q (By Mr. Roberts) Mr. Tunstahl, are you familiar with the Commission's Order R2824 entered in this case on December 7, 1964?

A Yes, I am.

Q With respect to Order R-2824, did you personally participate in your professional capacity, in the matters authorized by Order R-2824?

A I did, and on two occasions I did visit the location of the Jicarilla 28 Number 1 and did consult with our agent in Farmington and went over the application for the use of the dual flow check, the wire line operations connected therewith. I did not visually and personally witness it, but since that time, have been further informed by Continental Oil Company and have reviewed the information that was contained in this application.

Q Based upon all the information you have in regard to the installation of the dual flow choke on the Jicarilla 28 Well Number 1, did the tool prevent communication between the Gallup and Dakota zones at all times?

A Yes, sir, it did.

Q Will the tools so perform with any other Gallup-Dakota oil wells on Continental Oil acreage in the West Lindrith Field?

A It should perform very beautifully.

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Q And the reason for your conclusion in this regard is?

A From all the indications, from information from Continental Oil Company, the Jicarilla 28 Number 1 is a typical marginal operation in that field and should be a representative well of future development wells that might be drilled in connection with dual flow choke.

Q Based upon your experience with the tools in laboratory tests and actual field use, can you testify as to the reliability of the dual flow shoke in performing its intended function?

A It has performed its intended function here very nicely, and I might state that we have more performance data since we last appeared here at the last hearing, and all the applications that we have had have been successful.

Q The tool is used rather extensively in other areas of the country and overseas?

A Right, we have, or had at the time of the last hearing, essentially seventy-five in operating condition with the dual flow choke and one hundred total. By the end of this year we should have over one hundred fifty, or well over the hundred mark, at the time, actually operating.

Q Do you recall testifying on September 30, 1964, with regard to the distribution curve and the subtraction method of allocating production?

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A Yes, sir, I do.

Q Which is the suitable method to use in the case of the Jicarilla 28 Well Number 1?

A The suitable method here would be the straight subtraction method, based upon the caomparative operating conditions between single zone and combined zone production. In other applications with the Commission that we fall back into that same method, the distribution curves possibly indicate, but the original data which we tried to obtain for the long stabilization period on this low permeability reservoir were highly indicative that it would be necessary to conduct well tests in excess of those anticipated.

We had previously anticipated tests on the order of twenty-four to forty-eight hours in order to get stabilized rates, and there again, we ran into a limitation on the actual equipment because seven days is as long as you would be able to test anywhere; and subsequently the well, we might, if we are real lucky, get a stabilized rate in this period, but we would have no indication whatsoever that this data was true and correct, if we pulled the bomb, naturally we would have to back up and start over and any production which is missed in this particular application can be tacked on at the end. But then you have got to determine if the payment is there, and economics just don't justify continual exhaustive testing and we must fall back

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to subtraction methods in these marginal wells; where top string allowable wells will be encountered, at this time, if such is present, other distribution curve methods can be presented and closer check points made, and annual testing.

Q In your opinion, would the subtraction method of allocation of production be the suitable method with respect to any Gallup-Dakota marginal oil wells on the acreage in the West Lindrith Field?

A Yes, it would.

Q And I suppose the reason for this conclusion is the same as you have related with respect to to 28 Number 1?

A Yes, if it is typical, yes.

Q In your opinion, based upon actual experience with the tool, will the tool extend the economic life of any well in which it is used?

A So far we have extended the economic life of wells in which this tool has been used and have been able to recover, as we would in this case, hydrocarbon that would be left untouched and revenue for the producing company's wells and the state are concerned, if this tool were not applied.

Q In your opinion, would the approval by the Commission of the use of the dual flow choke on a permanent basis in the Jicarilla 28 Number 1 be in the interest of conservation, and permit the recovery of oil that would otherwise not be recovered

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from the Dakota well on the West Lindrith acreage?

A Yes, it would.

Q And will approval of this tool on a permanent basis otherwise prevent waste and protect correlative rights?

A Yes.

Q And can the same be said with respect to its use in any additional well on Continental Oil Company's West Lindrith acreage?

A Yes, sir, it can.

MR. ROBERTS: I have no further questions of this witness.

MR. NUTTER: I missed your name, sir.

THE WITNESS: Tunstahl.

CROSS EXAMINATION

BY MR. NUTTER:

Q Mr. Tunstahl, I noticed during Mr. Brown's testimony, he was going through these chronological events that occurred across the test period and there were two or three occasions where both zones were being commingled, and the Gallup was not entered. Now, what is the cause of this, is it misjudgment as far as the size of the orifice is concerned, or just what is it?

A In the application of all cases here, we have observed the same thing. We have a tubing pressure which is that

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pressure immediately above the dual flow choke and until this pressure is sufficiently reduced, or what it amounts to, until it reaches the static bottom pressure of the weaker zone, the check valve in the tool remains on seat and the pressure in the tubing at all times is higher than the pressure, static bottom hole pressure of the weaker zone, so consequently the weaker zone has no means to flow because it cannot flow uphill against the high pressure, and when the tubing pressure is sufficiently reduced, at that time we commence to get production from the weaker zone and continue to get additional production from the tubing which is lower down to its desired point of maximum production.

Then using a plunger lift like you have got here just means that your plunger has to work more quickly or more efficiently, you have to unload the well to a lower bottom hole pressure to get the weaker zone to come on.

Q What about this other problem that was encountered, where the Gallup was theoretically blanked off with the blanking plug, but there was indication of leakage, and they had to pull the tool to get the orifice and found the orifice was damaged? Is that a common occurrence?

A No, sir, it is not. I feel that is partially my responsibility, but it reverts back to a human error. We were instructing our agent on the use of a new tool and in the

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instruction of its use, whether I missed it and didn't tell him that it was necessary to knock out the plug, or whether he forgot to knock out the plug, in order to get the plunger --

Q Now, that would be the fishing tool, wouldn't it?

A No. You don't get it in the orifice head assembly. If we refer to this one, it will be easier to see. Here we have the orifice assembly, the prong, its supporting part in green. Now, when we blank the lower zone, we put the blanking device over on the left here, which is a ruptured disc, and here is a punch to rupture the disc, and for equalization this forms a piston down into here and the surface for this double "O" ring is the upper check valve assembly. When the upper check valve assembly starts into the tool, it must travel here. We have the orifice head assembly and this time, it's shown in green, the prong assembly, it must travel from this point down to here, all this down in here is a closed chamber and just like trying to put a packer into the tubing with a plug in the tubing string, there is no way to compress the fluid, and consequently you end up leaving the orifice head without having actually blanked it.

Q I see.

A It's necessary in the two-inch model to knock out a plug or rupture the disc in the assembly to allow the tremendous volume involved for this liquid. In other words, if we put it

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over the tremendous volumes, then we can put the orifice head in: if we are trying to put it in a two-inch area, there is just no way to compress that.

Q What was the problem with the fishing equipment?

A With the fishing of it, when we got ready to fish the check assembly out, to check it, at that time it had sand around it which was evidently left over from this operation of trying the orifice head in.

Q So the fishing problem was also a result of this original error?

A I would say it all stemmed from one error, the horseshoe nail.

Q And you think this is not a defect in the tool itself, but this was something that was a human error and can be corrected?

A Yes, sir, it is a human error and can be corrected. It won't happen again.

MR. BROWN: I would like to add here the error was human with the blank. We believe this is what happened. We blanked off the other zone. We were trying to blank off the upper zone, which you can blank off with the check valve assembly in there, you have a very short distance to move to seat on the upper assembly, and therefore, you can blank it off. We inadvertently, I believe what happened, put the blank

in the wrong opening and therefore, it was trying to seat in that closed cylinder and would not do it. The point was we were not trying to seat to blank off the other, but just got it in the wrong zone.

MR. NUTTER: I see. Are there any other questions of Mr. Tunstahl at this time? Mr. Tunstahl, did you get the tool?

A I got the tool back but our clerk is still screaming about the little orifice insert, but we won't bother about that.

MR. DURRETT: I think I have been told this before, but what does the tool cost?

A The dual flow choke sells for $1,200.00 for the two-inch, the landing device to seat it sells for about $150.00. It can be dressed up and modified and go on into just how elaborate you want from the simplest completion to the most elaborate, depending upon the niceties and extra niceties that might go along with it.

MR. NUTTER: If there are no further questions of Mr. Turnstahl, he may be excused.

(Witness excused.)

MR. ROBERTS: I offer Exhibits 1 through 7 into evidence.

MR. NUTTER: Continental's Exhibits 1 through 7 will be admitted in evidence.

(Whereupon, Exhibits 1 through 7 admitted in evidence.)

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MR. NUTTER: Do you have anything further, Mr. Roberts?

MR. ROBERTS: Only to say, Mr. Nutter, that we believe we demonstrated that the commingling tool is completely workable and reliable and we submit that in the interest of conservation, and Continental Oil Company ought to be permitted to use the tool on a permanent basis in the Jicarilla 28 Well Number 1, and use of this tool in the initial well on Continental Oil Company's sixteen section block in the West Lindrith Field as to the Gallup and Dakota zones as to marginal oil wells, that should be handled by application for administrative approval in accordance with the requirement of Rule 303B.

MR. NUTTER: Does anyone have anything they wish to offer in Case 3112? We will take the case under advisement and the hearing is adjourned.

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STATE OF NEW MEXICO)
) ss.
COUNTY OF BERNALILLO)

I, _____, Court Reporter, do hereby certify that the foregoing and attached transcript of proceedings before the New Mexico Oil Conservation Commission Examiner at Santa Fe, New Mexico, is a true and correct record to the best of my knowledge, skill and ability.

IN WITNESS WHEREOF I have affixed my hand and notarial seal this _____ day of _____, 1965.

_____
Notary Public - Court Reporter

My Commission Expires:

_____

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 3112 (re-opd) heard by me on 7/28, 1965.

_____, Examiner
New Mexico Oil Conservation Commission

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BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

June 9, 1965

EXAMINER HEARING

IN THE MATTER OF:

Case 3112 being reopened pursuant to the provisions of Order No. R-2824, which order authorized Gallup-Dakota commingling in the wellbore by means of a dual-flow downhole choke assembly in its Jicarilla 28 Well No. 1 located in Unit J. of Section 28, Township 25 North, Range 4 West, Rio Arriba County, New Mexico.

Case No. 3112

BEFORE: Elvis A. Utz

TRANSCRIPT OF HEARING

MR. UTZ: Case 3112. In the matter of Continental Oil Company for downhole commingling from the Gallup and Dakota zones, San Juan County.

MR. KELLAHIN: If the Examiner please, Jason Kellahin, representing Continental Oil Company. We would like to ask that this case be continued until the last Examiner Hearing in June.

MR. UTZ: Case 3112 will be continued to the June 30th hearing.

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STATE OF NEW MEXICO)
) ss
COUNTY OF BERNALILLO)

I, ADA DEARNLEY, Notary Public in and for the County of Bernalillo, State of New Mexico, do hereby certify that the foregoing and attached Transcript of Proceedings before the New Mexico Oil Conservation Commission was reported by me, and that the same is a true and correct record to the best of my knowledge, skill and ability.

WITNESS my Hand and Seal this 18th day of June, 1965.

Ada Dearnley
ADA DEARNLEY

My Commission Expires:

June 19, 1967.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 3112, heard by me on June 9, 1965.

Examiner
New Mexico Oil Conservation Commission

BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
June 30, 1965

EXAMINER HEARING

IN THE MATTER OF:
In the matter of Case 3112 being reopened pursuant to the provisions of Order No. R-2824.

Case No. 3112

BEFORE: Daniel S. Nutter

TRANSCRIPT OF HEARING

DEARNLEY-MEIER REPORTING SERVICE, Inc.
ALBUQUERQUE, N. M. PHONE 243-6691
SANTA FE, N. M. PHONE 983-3971
FARMINGTON, N. M. PHONE 325-1182

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MR. NUTTER: We will call Case 3112.

MR. DURRETT: In the matter of Case 3112 being reopened pursuant to the provisions of Order No. R-2824. If the Examiner please, I would like to state for the record that the Commission has received a request from Jason Kellahin the attorney for Continental, requesting that this case be continued to the last Examiner's hearing in August.

MR. NUTTER: Case Number 3112 will be continued to July 28th at this same time and place.

STATE OF NEW MEXICO)
)
COUNTY OF BERNALILLO)

I, Denny Watts, Notary Public in and for the County of Bernalillo, State of New Mexico, do hereby certify that the foregoing and attached Transcript of Proceedings before the New Mexico Oil Conservation Commission was reported by me, and that the same is a true and correct record to the best of my knowledge, skill and ability.

WITNESS my Hand and Seal this 15th day of July, 1965.

Denny Watts
DENNY WATTS

My Commission Expires:

April 9, 1969.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 3112, heard by me on July 28, 1965.

....., Examiner
New Mexico Oil Conservation Commission

NEW MEXICO OIL CONSERVATION COMMISSION

EXAMINER HEARING

SANTA FE, NEW MEXICO

REGISTER

HEARING DATE JUNE 30, 1965 TIME: 9 A.M.

NAME:	REPRESENTING:	LOCATION:
(illegible)		
James R. O'Brien	John L. Hamm	Midland
Jerry Henderson	El Paso Natural Gas	El Paso
Garrett C. Whitworth	El Paso Natural Gas	El Paso Tex.
John W. Hoover	Gulf Oil Corp.	Roswell
Bill Kastler	Gulf Oil Corp.	Roswell
Frank S. Irby	State Engr	Santa Fe
[illegible]	[illegible]	[illegible]

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BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
June 9, 1965

EXAMINER HEARING

IN THE MATTER OF:

Case 3112 being reopened pursuant to the provisions of Order No. R-2824, which order authorized Gallup-Dakota commingling in the wellbore by means of a dual-flow downhole choke assembly in its Jicarilla 28 Well No. 1 located in Unit J of Section 28, Township 25 North, Range 4 West, Rio Arriba County, New Mexico.

Case No. 3112

BEFORE: Elvis A. Utz

TRANSCRIPT OF HEARING

MR. UTZ: Case 3112. In the matter of Continental Oil Company for downhole commingling from the Gallup and Dakota zones, San Juan County.

MR. KELLAHIN: If the Examiner please, Jason Kellahin, representing Continental Oil Company. We would like to ask that this case be continued until the last Examiner Hearing in June.

MR. UTZ: Case 3112 will be continued to the June 30th hearing.

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STATE OF NEW MEXICO)
) ss
COUNTY OF BERNALILLO)

I, ADA DEARNLEY, Notary Public in and for the County of Bernalillo, State of New Mexico, do hereby certify that the foregoing and attached Transcript of Proceedings before the New Mexico Oil Conservation Commission was reported by me, and that the same is a true and correct record to the best of my knowledge, skill and ability.

WITNESS my Hand and Seal this 18th day of June, 1965.

ADA DEARNLEY

My Commission Expires:

June 19, 1967.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 3112, heard by me on June 9, 1965.

Examiner
New Mexico Oil Conservation Commission

Railroad Commission of Texas

OIL AND GAS DIVISION

COMMISSIONERS
BEN RAMEY
Chairman
ERNEST O. THOMPSON
WILLIAM J. MURRAY, JR.
O. D. RYNDAM, Secretary

Chief Engineer

AUSTIN, TEXAS
March 21, 1963

Gulf Oil Company
Box 2093
Beaumont, Texas

ATTENTION: Mr. Joe A. Owens & Mr. J. W. Hodges

IN RE: Rule 15 exception in the STOWELL FIELDS, Chambers County.

Gentlemen:

The Commission, at conference March 21, 1963, approved your application for permission to operate a multiple completion choke assembly in your Hankamer Well No. 2-C and No. 2-T in the Stowell Fields. Testimony offered at the hearing indicated oil would be produced from the Upper Discorbis Zone through perforations 7,337' to 7,342' and gas with condensate would be produced from the Discorbis Zone through perforations 7,452' to 7,456'.

At the conclusion of a six months testing period, a review of the performance data obtained from the subject well will be made. Required testing of the subject completions shall include an initial test and additional tests to be made quarterly thereafter.

Yours very truly,

Arthur H. Barbeck B.D.T.

Arthur H. Barbeck
Chief Engineer

BDT:cbr
cc - RRC - Houston, Texas
Bob Harris
Otis Engineering Corp.

Railroad Commission of Texas

OIL AND GAS DIVISION

AUSTIN, TEXAS

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Chief Supervisor
ARTHUR H. BARBECK
Chief Engineer
ROSS BELL
Chief Accountant

October 18, 1963

Sun Oil Company
P. O. Box 2831
Beaumont, Texas

Attention: Mr. Joe A. Owens

In Re: Your Application for Purpose of Reviewing Performance Data on your Hankamer Well No. 2-U and Well No. 2-L, Stowell Fields, Chambers County, Texas

Gentlemen:

At a formal conference held October 18, 1963, the Commission considered the evidence submitted by you in connection with the operation of an Odis Multiple Completion Choke Assembly and ruled that you be allowed to continue operating the subject wells with the choke assembly in place since one zone is gas and the other zone is apparently a salvage oil operation.

You will be required to conduct quarterly tests and submit the results to this office on each of the subject wells.

Yours very truly,

Bob R. Harris, Director
Research and Inspection

BRH:pw

cc: Mr. Winston D. Tyler
RRC - Houston, Texas

Sun Oil Company
P. O. Box 2831
Beaumont, Texas
Attention: Mr. J. W. Hodges

Mr. Carroll F. Burton
P. O. Box 1511
Bay City, Texas

D, D' n'

THE MULTIPLE COMPLETION CHOKE ASSEMBLY - A NEW PROFIT MAKING TOOL

by

J. W. Hodges
Sun Oil Company
Beaumont, Texas

--O--

For presentation at the 15th
Annual Technical Meeting
PETROLEUM & NATURAL GAS DIVISION,
C. I. M.
May 6-8, 1964
Calgary, Alberta

The Multiple Completion Choke Assembly - A New Profit-Making Tool

Abstract

This paper describes the construction, method of operation, and field performance of the Sun Oil Company-developed Multiple Completion Choke Assembly.

This down-hole commingling tool has been in operation since March, 1960. It has been used in approximately 75 wells located in Louisiana, Texas, Mississippi, Oklahoma, Mexico, Kuwait, and India.

Sun Oil Company's Gulf Coast Division, through the use of this tool during the past four years, has saved approximately $289,000 in tubular goods, and produced approximately $282,750 worth of hydrocarbons not otherwise recoverable.

The paper reports the results of Sun Oil Company's installations and discusses the various applications and limitations of the tool.

The method of allocating production to each zone is explained.

Advantages and disadvantages in simultaneous production of two separate reservoirs through a single tubing string are enumerated.

Construction and Operation

Fig. 1 shows a well equipped to receive a multiple completion choke assembly. A retainer type packer separates the two producing zones. The upper packer is optional. A side-door choke landing nipple hookup is located in the tubing 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, as shown in Fig. 2. The outer assembly, which is run on a wire line and locked in the landing nipple, contains the check valves and packing seals which prevent flow from one zone to the other.

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. 3.

Fig. 4 is a schematic drawing which shows how the device works. Production from the lower zone enters the assembly through a slotted section, flows through a sleeve-type check valve, enters and flows through the tube of the orifice-head assembly, 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 section, through 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 segregated to this point, combine and flow to the surface.

Allocation of Production

Detailed instructions for testing and allocation of production are available in the manufacturer's "Service Manual for

Otis Type 'S' Multiple Completion Choke Assembly--Dual Flow"; in general, however, allocation is based on the results of a stabilized test of one of the zones while the other zone is blanked off. The established rate from this zone is then subtracted from the commingled rate to calculate production from the second zone.

Test procedure will depend on whether or not one of the zones is in critical flow. A stream is in critical flow when alterations in pressure downstream from an orifice do not affect the rate of flow. The critical point in a gas stream flowing through an orifice occurs when the pressure downstream from the orifice is 53% of the upstream pressure; for gas-liquid mixtures, the critical ratio is higher but should not exceed approximately 0.58.

If one of the zones is in critical flow, alterations in the tubing inlet pressure (the pressure immediately downstream from the multiple completion tool) will not change the predetermined rate from that zone, and the allocation process is simplified.

If neither zone is in critical flow, the zone with the higher pressure is tested individually at several rates in a range of tubing inlet pressures expected to occur during commingled flow. By plotting the rate versus tubing inlet pressure, a graph is obtained from which the production from the zone can be determined during commingled flow. Fig. 5 shows the results of such a test in the Kinder Field, Louisiana. This graph can be used to determine the rate from the lower zone during commingled flow. If the zone is out of critical flow, its rate is a function of the tubing inlet pressure.

The method of allocating production with the multiple completion tool is basically the same as that used in conventional

practice; i.e., determining the rate from each zone by testing, commingling the production downstream from the choke beans, and allocating the interim production between test periods on the basis of the individual tests. In either case, accurate allocation depends upon the consistency with which each zone continues to produce at its tested rate, and this is in large measure dependent upon accurate flow rate control. The tungsten carbide choke beans in the multiple completion choke assembly, being highly resistant to erosion and located below the zone of paraffin deposition (precluding plugged chokes) will provide better flow rate control than will conventional surface chokes. In Sun's wells, the orifice head has been pulled approximately 450 times, and in each instance the chokes have remained true to gauge.

Applications

The multiple completion choke assembly is not a specialty tool. It is applicable in almost any type of multiple completion. Sun Oil Company has made nineteen installations in wells ranging in depth from 3790' to 15,576' and in bottom hole pressure from 814 psi to 8173 psi.

It is applicable in multiple oil, multiple gas, and combination oil-gas wells.

It can be run on initial completion, or in the conversion of a concentric or twin string dual completion. In the latter case, when either zone becomes deficient, the tool can be installed with wire-line tools, preferably in a Type "S" side-door choke landing nipple; a hook-wall tool is available, however, if a side-door nipple has not been run.

A list of its applications follows.

1. In wells where one or both zones require artificial lift, one set of gas lift valves can be used to produce the two zones through the tool at reduced cost and greater efficiency than is possible in other types of dual completions.

2. As a means of using gas-cap gas to lift liquids from the lower part of the same sand.

3. Two multiple completion tools can be used with dual strings of tubing to produce either three, four, or five zones simultaneously.

4. The tool is compatible with slim hole multiple completions.

5. Applicable to tubingless completions and permanent type completions.

6. Can be used to produce selective completions dually.

7. Can be modified and used to inject salt water or gas into separate reservoirs with reasonably accurate allocation to each reservoir.

There are two limitations to the use of the tool: 1) where there is excessive sand production and 2) where there is insufficient reservoir energy for required production and external gas is not available for gas lift.

Table No. 1 describes the wells in which Sun has used the multiple completion choke assembly.

Advantages

The advantages in using the multiple completion choke assembly are as follows:

1. Reduction in well equipment costs. In Sun Oil Company's Belle Isle Unit #1-56, Belle Isle Field, Louisiana, approximately $42,000 was saved on equipment alone as compared to a twin string dual.

2. Increased ultimate recovery. The economy of the method has resulted in production from reservoirs which would not have been tested otherwise. For example, in Sun's Belle Isle Unit #3-5, over $97,000 worth of hydrocarbons were produced in the first year of operation from a questionable zone that would have been written off if this tool had not been available.

3. Increased daily production. The income from Sun's Vicksburg Unit #3, Kinder Field, Louisiana (the lower zone in a dual completion), has increased from $2770 per month to $8500/month since installation of the tool in March, 1960. The gas-oil ratio has decreased from 54,000 c.f. per bbl to 19,600 c.f. per bbl. See Fig. 6.

4. Reduction in workover costs (compared to multiple-string completions.)

5. Reduction in surface equipment costs. This includes heaters, separators, compressors, high pressure gas-lift lines, meters, etc.

6. Maximum use of reservoir gas. By bottom hole choking and commingling production immediately above the tool, gas breaking out of solution at this point results in the lowest possible gradient in the tubing. When a strong well is combined with a weak well in this way, the weak well can be produced at its maximum potential. This not only prevents waste; it is also quite economical to the operator, as it postpones or eliminates the need

to provide artificial lift for the weaker zone. Conventional completions, by maintaining separation of production to the surface, in this respect act contrary to the principles of conservation.

The multiple completion choke assembly is in effect a single-point injection, retrievable flow valve, utilizing gas supplied directly from the formation at maximum efficiency. To illustrate the degree of efficiency, in Sun Oil Company's Dishman-Lucas #1, Sour Lake Field, Texas, a comparison was made between this method and a conventional gas lift system. This study showed that the multiple completion tool used one-sixteenth as much gas and produced twice as much liquid.

7. Reduction in corrosion inhibitor and paraffin treatment costs.

Disadvantages

1. Cost of testing. The periodic testing required results in wire-line costs otherwise not incurred; however, there are two important considerations that should not be overlooked: (a) the future value of the money saved by virtue of using the tool. In Belle Isle Unit #1-56, the $42,000 saved in initial cost is worth $44,520 at 6% compound interest after one year, $56,205 after five years, and $75,215 at the end of ten years. Obviously, this gain in value will absorb wire-line costs (which have run from $50 per month to $150 per month in Sun's nineteen wells); (b) the use of the tool will result in an increase in production in most wells. The income from just one additional barrel of oil per day will in most instances pay the wire-line costs.

2. Somewhat more complicated (technical) method of

production accounting. The engineer in charge must practice more of his production technology than is normally required in routine production accounting. This may or may not be a disadvantage, and the bulk of the work can still be handled by the production clerk.

Attitude of the Conservation Agencies

Co-operation of the various State agencies has come about through recognition that 1) commingling down hole with the choke assembly is no different from commingling at the surface; 2) the tool is mechanically sound; 3) the tool will prevent waste and increase ultimate recovery; and 4) most of the people in the oil industry are honest. Those that aren't will find a cheaper way to produce multiple completions dishonestly.

Conclusions

Simultaneous production of two reservoirs through a single string of tubing will in many wells result in a significant reduction in completion and lifting costs and increase in current income and ultimate recovery. The Multiple Completion Choke Assembly will maintain separation of reservoirs and control the rate of production from each. Test procedures have been developed which provide an acceptable method of determining the production from each zone. All requirements imposed by the State regulatory agencies can be satisfied.

Well	Field	Depth, Ft.	Static Bottom Hole Pressure, Psi	Bbl Liquid Per Day	Gas-Oil Ratio Cu Ft Per Bbl
Unkel #1	Kinder, La.	8,067	2,575	6 Oil	22,100
		8,448	2,460	19 Cond	18,466
Miami B.S. #2	Bayou Sale, La.	14,025	5,870	20 Oil	1,000
		14,236	6,533	75 Oil, 75 SW	7,750
Houston #3	Kinder, La.	7,678	3,263	64 Oil	784
		8,379	3,371	37 Cond	19,100
B.I.U. #3-5	Belle Isle, La.	13,958	6,500	129 Oil	735
		13,983	6,500	129 Oil	945
K. C. "A" #2	Kinder, La.	7,394	3,290	7 Oil, 15 SW	643
		8,390	3,485	64 Cond	16,188
B.I.U. #1-56	Belle Isle, La.	12,840	5,670	115 Oil	906
		13,398	5,781	129 Oil	423
State Lse 1337 #22	Bateman Lake,La.	10,154	4,538	71 Oil	2,929
		11,700	5,060	65 Oil, 10 SW	3,354
Carpenter #4	Sour Lake, Texas	4,710	814	Gas	-
		4,788	1,093	14 Oil	649
State Lse 1337 #15	Bateman Lake,La.	11,749	5,335	120 Cond	29,300
		11,828	5,331	132 Oil	1,060
Dishman-Lucas #1	Sour Lake, Texas	9,610	4,340	Gas	-
		9,800	3,778	21 Oil, 325 SW	1,143

Table 1.--Sun Oil Company Wells Using Multiple Completion Tool

Well	Field	Depth, Ft.	Static Bottom Hole Pressure, Psi	Bbl Liquid Per Day	Gas-Oil Ratio Cu Ft Per Bbl
Jones #2	Conroe, Texas	3,790	1,634	Gas	-
		5,043	2,100	28 Oil, 298 SW	893
Chachere #2	Kinder, La.	6,680	3,290	Sanded Up	-
		8,062	2,300	2 Oil	54,049
Regan #2	Egan, La.	9,855	3,636	12 Cond	26,250
		10,067	3,850	121 Oil, 684 SW	995
LeBlanc Pool #1	Egan, La.	9,360	4,169	17 Cond	130,000
		9,872	4,195	48 Oil, 912 SW	1,271
Hankamer #2	Stowell, Texas	7,337	Not Meas.	10 Oil, 240 SW	2,100
		7,452	3,242	Dry Gas	-
State Lse 2620 #10	Lake Pelto, La.	15,532	8,018	196 Oil	2,200
		15,574	7,032	130 Oil	2,400
State Lse 2620 #11	Lake Pelto, La.	15,537	8,173	132 Oil	6,200
		15,576	8,099	84 Oil	4,040
Sun Fee "B" #6	Hull, Texas	9,904	5,500	100 Oil	750
		9,992	5,500	27 Oil	800
B.I.U. #1-61	Belle Isle, La.	13,478	5,441	142 Oil 37 SW	1,027
		14,392	6,500	159 Oil	1,410

Table 1 cont'd.--Sun Oil Company Wells Using Multiple Completion Tool

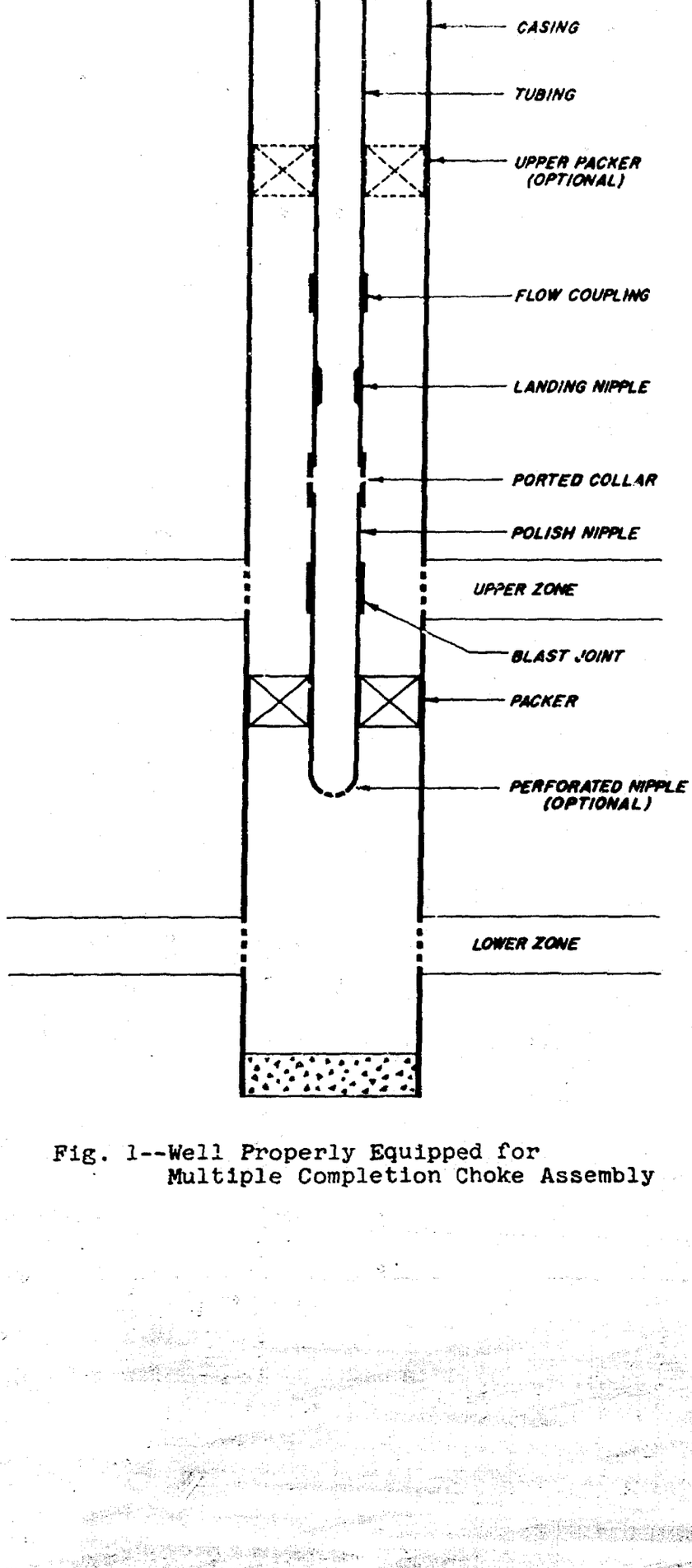


Fig. 1--Well Properly Equipped for Multiple Completion Choke Assembly

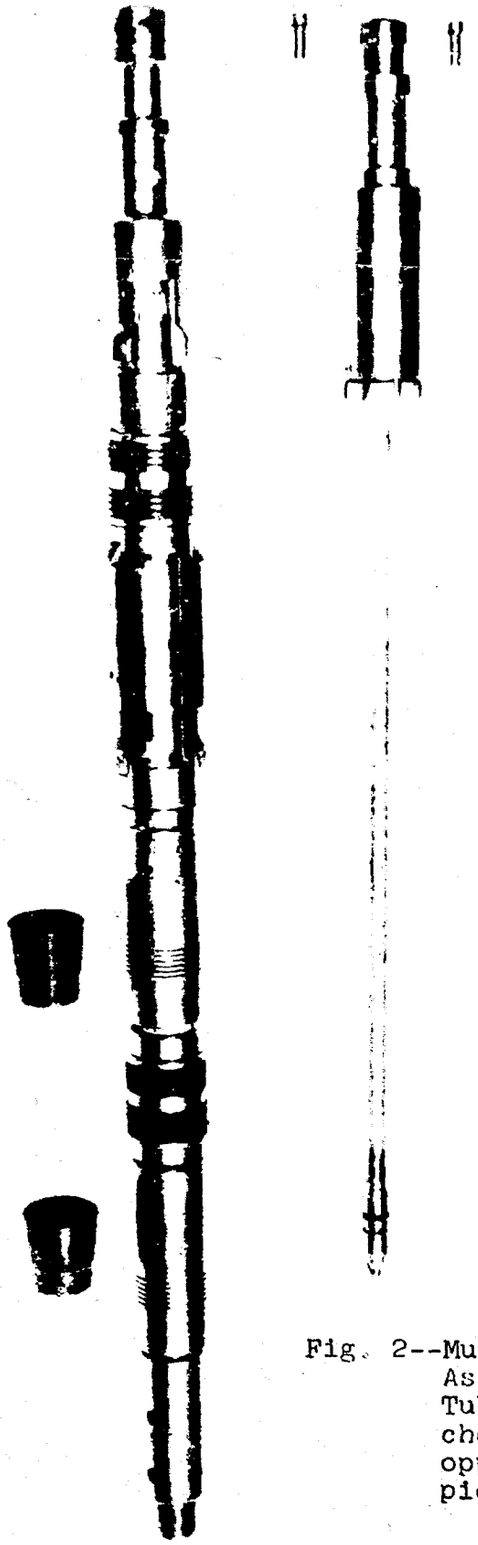


Fig. 2--Multiple Completion Assembly for 2-3/8-in, Tubing. Check valves and choke beans are shown opposite position occupied within tool.

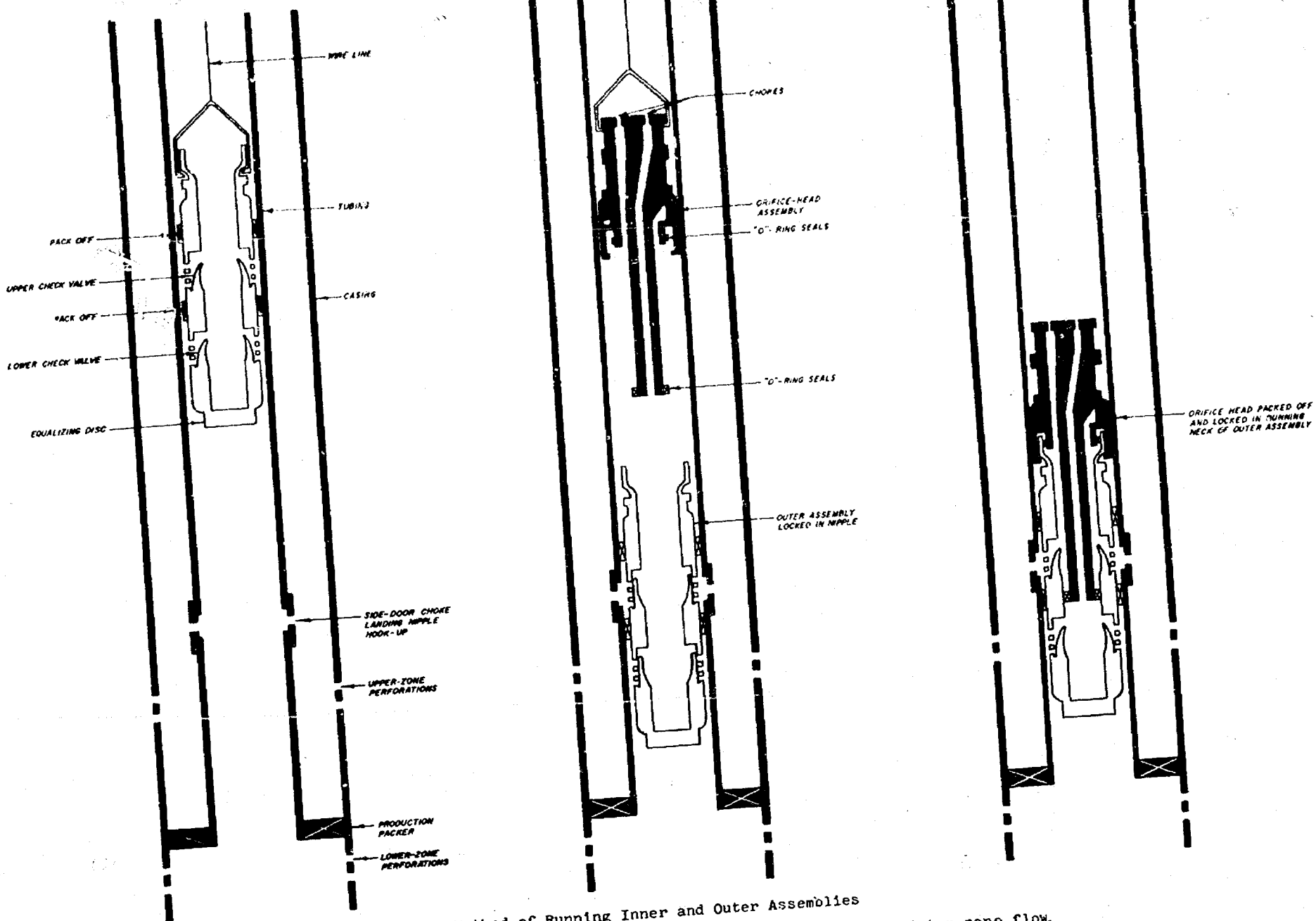


Fig. 3--Method of Running Inner and Outer Assemblies

Note in center drawing that check valves prevent inter-zone flow.

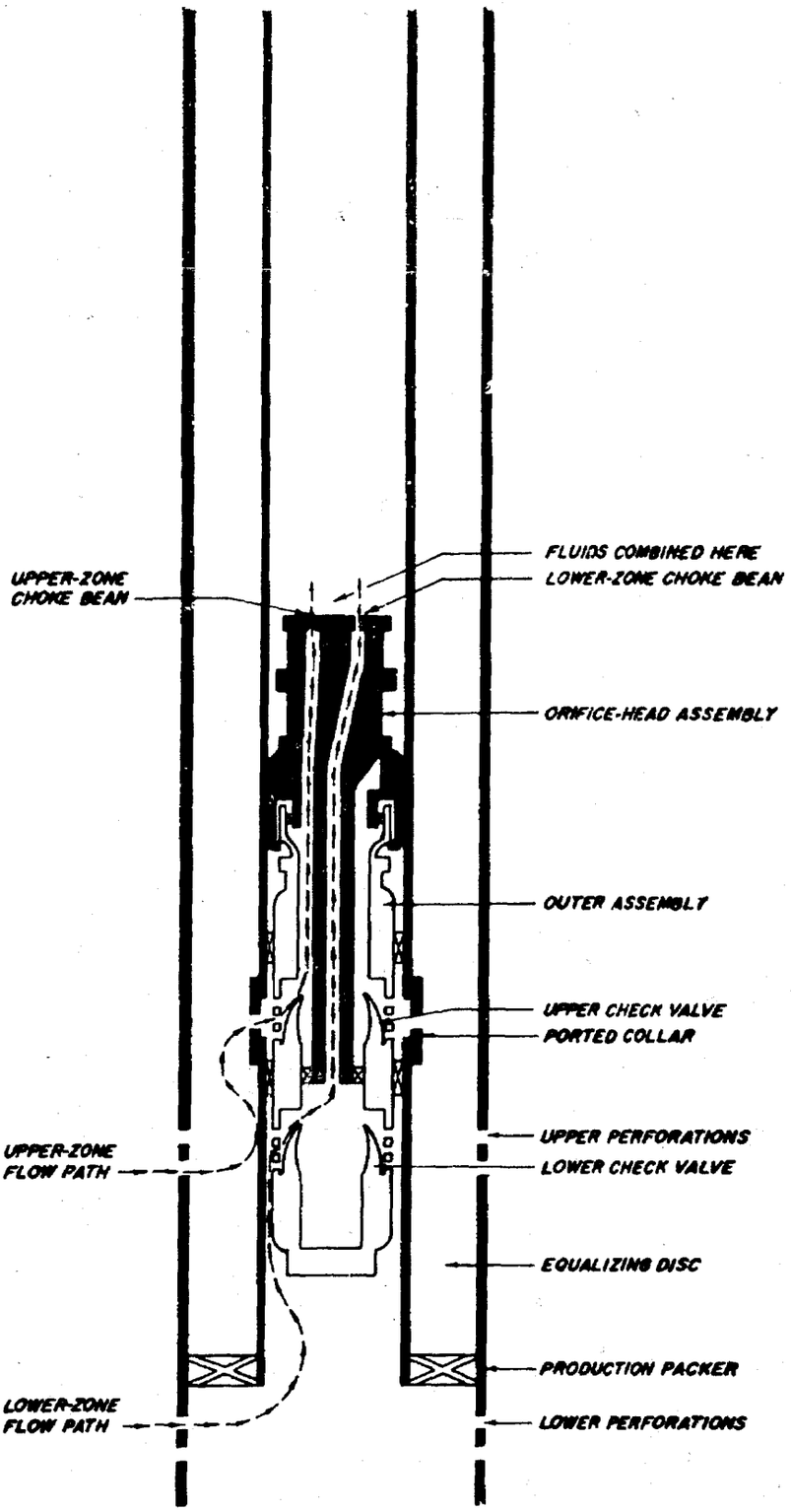


Fig. 4--Schematic Drawing Showing Operation of Multiple Completion Choke Assembly

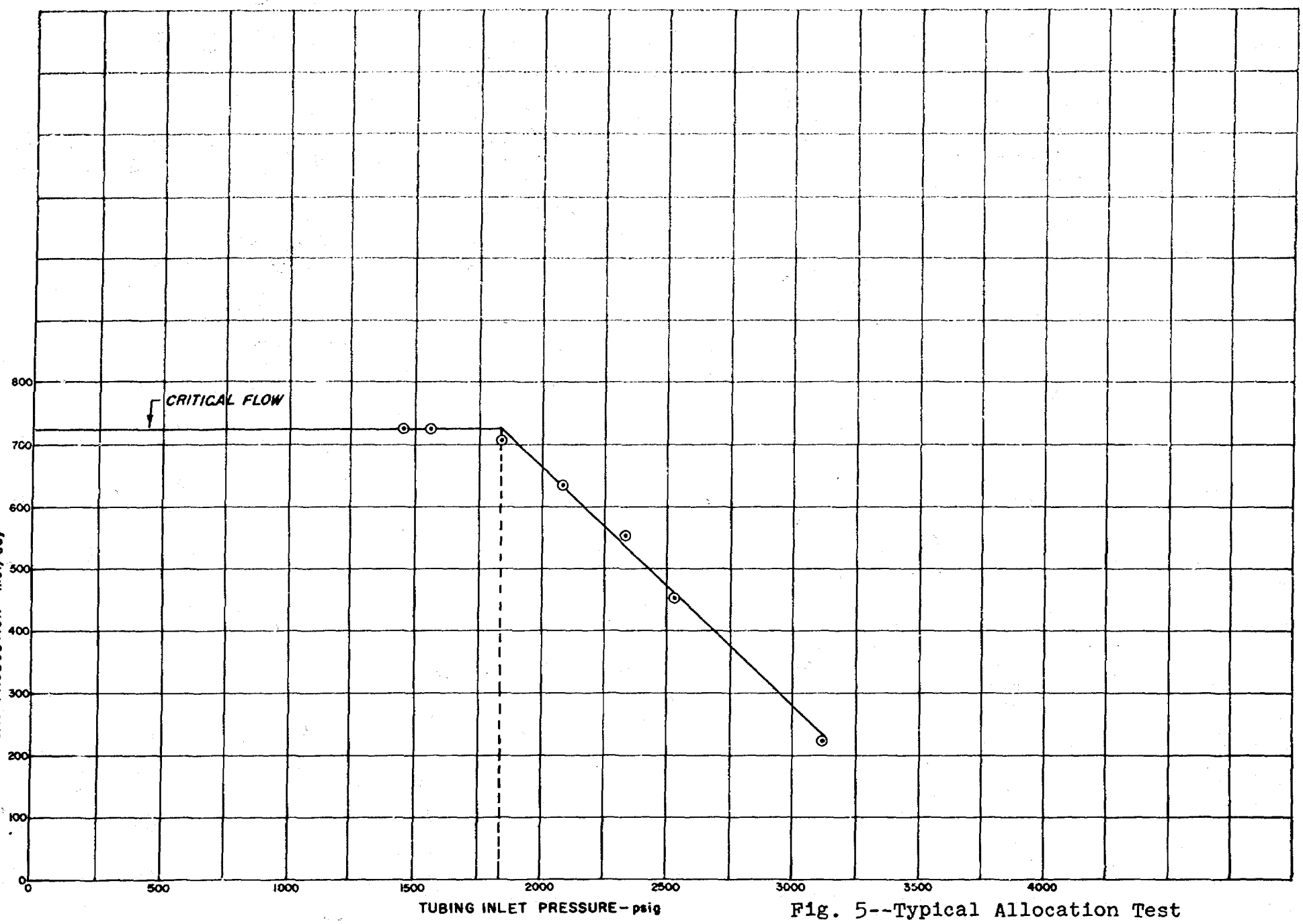
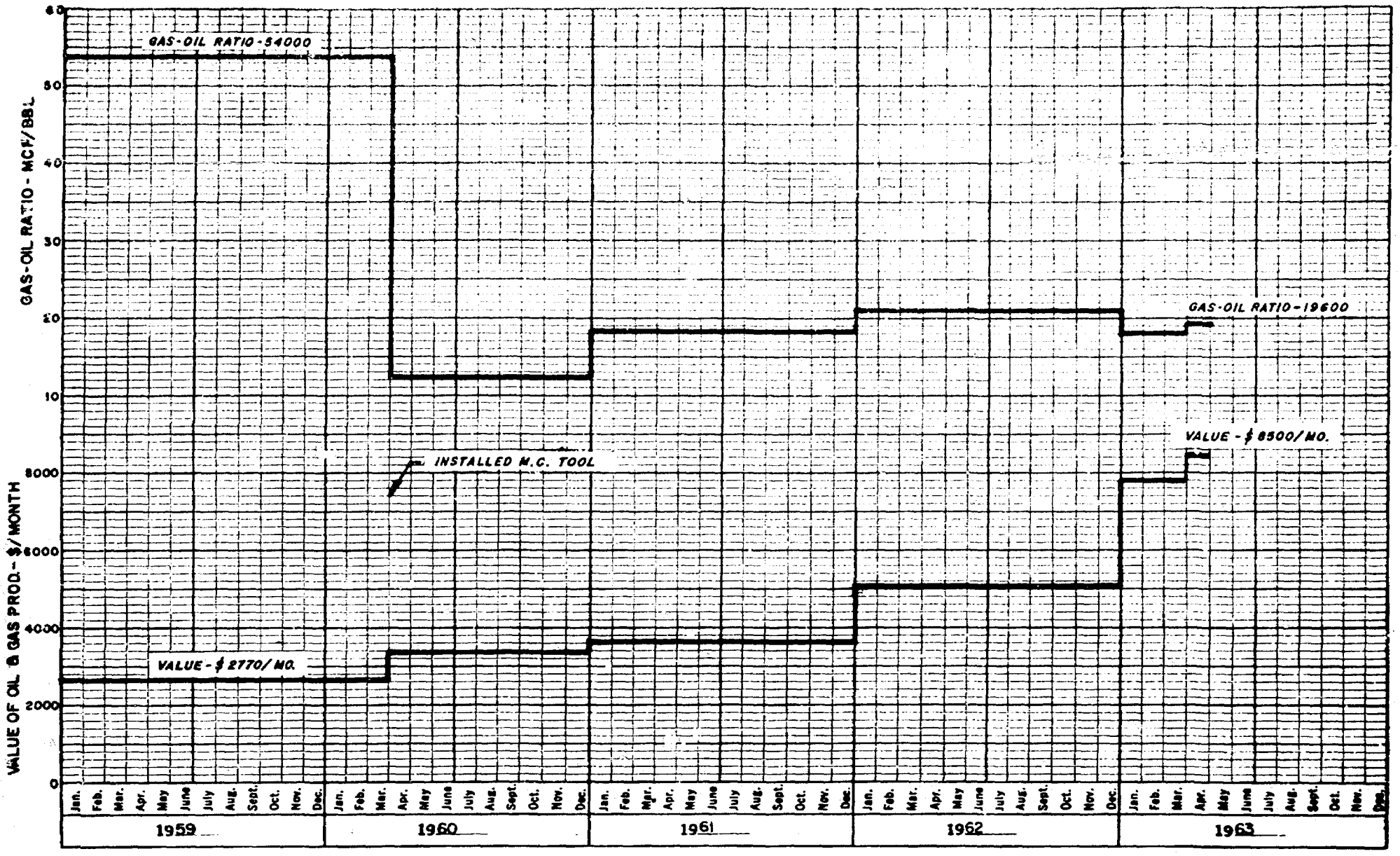


Fig. 5--Typical Allocation Test



VICKSBURG UNIT NO. 3 (LOWER ZONE)
KINDER FIELD

Fig. 6--Results of installation of Multiple Completion Choke Assembly.

RAY C. JONES, Chairman
HAROLD FREEMAN, Vice-Chairman
WILBURN CARTWRIGHT, Member
CARL B. MITCHELL, Secretary
DAN R. DUNNETT, Director Of Conservation
FERRILL H. ROGERS, Conservation Attorney
D. L. JONES, Assistant Director
STANLEY ROGERS, Assistant Director
W. J. MARSHALL, Assistant Director
W. H. SOLLERS, Trial Examiner
RALPH L. WAMPLER, Asst. Conservation Atty.
NELL RHODES FISHER, Asst. Conservation Atty.

OKLAHOMA

Corporation Commission

OKLAHOMA CITY . . . . OKLAHOMA

OIL AND GAS CONSERVATION DEPARTMENT

Dated Dec 4, 1963

Mr. Russell Thompson
Attorney at Law
1719 First National Building
Oklahoma City 2, Oklahoma

Mr. James R. Marty
Amerada Petroleum Corporation
Liberty Bank Building
Oklahoma City 2, Oklahoma

Michael B. Silva, Attorney
Phillips Petroleum Company
Oklahoma Mortgage Building
Oklahoma City 2, Oklahoma

Mr. Karl Tunstall
Otis Engineering Corp.
301 S. E. 29
Oklahoma City, Oklahoma

Mr. Joe A. Owens
Sun Oil Company
P. O. Box 2831
Beaumont, Texas

Mr. A. J. McCreedy
Socony Mobil Oil Company
120 Northwest 2
Oklahoma City 2, Oklahoma

Mr. William A. Dow
Cities Service Oil Company
Box 4577
Oklahoma City 2, Oklahoma

Gentlemen:

Re: Cause CD No. 19034

Enclosed find copy of Report of Trial Examiner in the above cause, which will be filed on the 9th day of December, 1963, and you have until December 12, 1963, in which to file exceptions thereto, if you so desire.

Yours very truly,

CORPORATION COMMISSION OF OKLAHOMA

Ralph L. Wampler

Ralph L. Wampler
Trial Examiner

RLW/b
encl.

12-12

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF SINGER OIL OPERATING COMPANY TO AMEND ORDER NO. 44297 CREATING GENERAL RULES AND REGULATIONS GOVERNING THE DRILLING OF OIL AND GAS WELLS AND THE PRODUCTION THEREFROM IN THE STATE OF OKLAHOMA, SO AS TO PERMIT THE USE OF A CHOKE ASSEMBLY IN DUAL AND MULTIPLE COMPLETION	))))))	CAUSE CD NO. 19034

REPORT OF THE TRIAL EXAMINER

This cause came on for hearing before the Corporation Commission of Oklahoma on the 25th day of October, 1963, and when said cause was called the same was referred to Ralph L. Wampler, Trial Examiner, for the purpose of taking testimony and reporting to the Commission.

At the time said cause was heard, Russell Thompson, Attorney, appeared for the applicant, Singer Oil Operating Company; Michael B. Silva, Attorney, appeared for Phillips Petroleum Company; Joe A. Owens appeared for Sun Oil Company; William A. Dow appeared for Cities Service Oil Company; James R. Marty appeared for Amerada Petroleum Corporation; Karl Tunstall appeared for Otis Engineering Corp.; and A. J. McCreedy appeared for Socony Mobil Oil Company.

The Trial Examiner proceeded to hear said cause and reports the following:

F I N D I N G S

1. That this is the application of Singer Oil Company for an order amending the Commission's General Rules as set out in Order No. 44297 so as to permit the use of a choke assembly dual and multiple completions.

2. That the Commission has jurisdiction over the subject matter herein; that notice has been given in all respects as required by law and no protests have been entered to the granting of the application.

3. That the applicant has an interest in the production of oil and gas in Oklahoma and proposes to use the Otis Choke Assembly in Oklahoma, if authorized to do so. The subject of this hearing is a new choke assembly whereby the production from each zone in a given well is calculated by providing individual chokes for each zone. Each producing zone is tested individually in order to determine the correct orifice for each zone, then the production from each zone is commingled in the well bore. When the hydrocarbons reach the surface, each producing zone is allocated a portion of the production, which is based on tests conducted on each zone prior to the commingling. Rather than run separate tubing to each zone, the hydrocarbons are commingled and the production from each zone is calculated and assigned accordingly.

4. To permit the use of this choke assembly would require the amendment of Sections 310 and 311 of Order No. 44297. Section 310 specifically prohibits the commingling of the production in the well and sets out how the production from each zone shall be measured. Section 311 provides that gas may be used for the artificial lifting of oil where all such gas returned to the surface with the oil is lawfully used, but where the returned gas is not to be so utilized, the use of gas for artificial lifting of oil is prohibited unless otherwise ordered by the Commission. The commingling of the production in the well would possibly result in the gas from one zone lifting the production of oil from the other zone and therefore an exception would need to be made which would permit this use of the gas even though there is no market for the gas.

5. The use of this choke assembly would result in substantial savings in that it would save the running of separate tubings to each of the producing formations. The amount of the savings would vary, depending on, among other things, the depth of the productive formations.

6. All the companies at the hearing supported this application with the exception of Socony Mobil, who had no comment and Cities Service who filed a statement which, in general, stated that the Otis Choke Assembly may be beneficial but had definite limitations and thought that a hearing should be held in each case if the Commission authorized its use.

7. It appears that whether or not this choke assembly should be used, would depend primarily on its accuracy. Nothing in this record would show anything but that the apparatus is very accurate. Any inaccuracy would come from the calculations made by the personnel allocating the production to each zone from the commingled production from the zones. There is little question but what the production from a weak zone could easily be boosted by the production from a stronger zone by merely adjusting the allocation figures, or any number of other ways. It is presumed, however, that all operators make a sincere and honest report of production. The use of the choke assembly will not change the honesty or dishonesty of anyone.

8. So, after consideration of all the facts, evidence and circumstances in this case, it is therefore recommended that the Commission enter its order granting the application and that the Commission amend Sections 310 and 311 of Order No. 44297 as set out in Exhibit "A" attached hereto; that the Commission further require operators to test the choke assembly in accordance with the procedures as set out on Exhibit "B" attached hereto; further, that the operators be required to file the results of such tests with the Director of Conservation upon complation of same.

DATED this 4th day of December, 1963.

Ralph L. Wampler

Ralph L. Wampler, Trial Examiner

RLW/b

310. CONTROL OF MULTIPLE COMPLETED WELLS

(a) Every multiple completed well shall be equipped, operated, produced and maintained so that there will be no commingling of the production from said formations in the well except as hereafter provided, and the production from each of said formations shall be either measured by a positive displacement dump-type continuous-flow measuring device or a measuring device authorized by the Commission after notice and hearing, and separately reported as required by the Commission, or shall be separately stored and measured on the lease in such a manner that the pipe line company or purchaser can separately identify the production from each of said formations and separately report the same to the Conservation Department of the Commission.

(b) Where permitted by the Commission upon notice and hearing for each individual well, the production from each formation may be produced through a multiple choke assembly so designed and located in the well bore as to segregate the formations, preventing commingling within the formations, but permitting commingling in the tubing string through individual choke orifices. The commingled production shall be separately measured at the surface and allocated to each formation on the basis of tests using the orifice principle of measurement.

(c) Upon request by the Director of Conservation, any multiple completed well shall be tested at any time to demonstrate the effectiveness of the separation of sources of supply, such tests to be witnessed by representatives of the Commission and by offset operators if desired.

311. USE OF GAS FOR ARTIFICIAL LIFTING

(a) Gas may be used for the artificial lifting of oil where all such gas returned to the surface with the oil is lawfully used. Where the returned gas is not to be so utilized, the use of gas for artificial lifting of oil is prohibited, unless otherwise specifically ordered by the Commission upon hearing.

(b) The use of production from one common source of supply to assist in lifting the production from another common source of supply by commingling the production from both common sources of supply in the tubing string shall be permitted in those instances in which the operator is otherwise authorized to so commingle the production in the tubing.

TESTING PROCEDURE FOR USE WITH A MULTIPLE FLOW CHOKE ASSEMBLY

1. Procure the necessary information to calculate the correct size of the flow bean for each crifice in the assembly.

2. Install the orifice assembly with one side blanked off and the other side with a flow bean of the calculated size.

3. Run a production test for 24 hours at stabilized rate of flow measuring all fluids and gasses produced.

4. Pull the choke assembly and place the correct size orifices in both sides and replace choke assembly.

5. Run a production test at a stabilized rate for 24 hours.

6. Calculate production from each zone on the basis of production from both zones less production from the individual zone.

7. At six month intervals repeat the testing procedure and run bottom hole pressures by:

(1) Removing the orifice assembly and blanking one side and taking a 24 hour bottom hole pressure test.

(2) Remove the assembly, blank the other side and take the 24 hour bottom hole pressure test.

8. Orifices will be sized so that the well will not produce at a rate in excess of 1.3 times the current allowables.

9. Orifices will be sized so that no zone will produce in excess of established field gas oil ratios.

10. Data will be furnished the Commission on forms approved by the Commission.

EXHIBIT "B"

JAY C. JONES, Chairman | HAROLD FREEMAN, Vice-Chairman | WILBURN CARTWRIGHT, Member | CARL B. MITCHELL, Secretary
DAN R. DUNNETT, Director Of Conservation | FERRILL H. ROGERS, Conservation Attorney
D. L. JONES, Assistant Director | STANLEY ROGERS, Assistant Director | W. J. MARSHALL, Assistant Director
W. H. SOLLERS, Trial Examiner | RALPH L. WAMPLER, Asst. Conservation Atty. | NELL RHODES FISHER, Asst. Conservation Atty.

OKLAHOMA

Corporation Commission

OKLAHOMA CITY . . . . OKLAHOMA

OIL AND GAS CONSERVATION DEPARTMENT

January 7, 1964

Mr. Russell Thompson, Att'y
1719 First National Bldg.
Oklahoma City, Oklahoma

Mr. Michael B. Silva, Att'y
Phillips Petroleum Company
Oklahoma Mortgage Building
Oklahoma City, Oklahoma

Mr. J. A. Owens
Sun Oil Company
Box 2831, Beaumont, Texas

Mr. Wm. A. Dow
Cities Service Oil Co.
Box 4577, Okla. City, Okla.

Mr. James R. Marty
Amorada Petroleum Corp.
2703 Liberty Bank Bldg.
Oklahoma City, Okla.

Mr. Karl Tunstall
Otis Engineering Corp.
301 S. E. 29th
Okla. City, Okla.

Mr. A. J McCreedy
Socony Mobil Oil Co.
Petroleum Club Bldg.
Oklahoma City, Oklahoma

Dear Sir:

Re: Cause CD No. 19034

Enclosed please find copy of Order No. 53749 entered by the Corporation Commission of Oklahoma.

Cordially yours,

Ferrill H. Rogers

FERRILL H. ROGERS,
Conservation Attorney

FHR:fls

...ATION COMMISSION OF THE STATE OF OKLAHOMA

...ation of Singer Oil ...)
...Order No. 44297 Creating ...) CAUSE CD NO. 19034
...Rules Governing the Drilling ...)
...Certain Wells in the Bemis-Shidler ...)
...Order No. ...) ORDER NO. 53749
...Rules Governing Said Field ...)

COMMISSION PROCEEDINGS

This cause came on for hearing before the Corporation Commission of Oklahoma on the [illegible] day of October, 19[illegible] 10:00 o'clock a.m., in the Commission's Court Room, Capitol Hill Building, Oklahoma City, Oklahoma; the Honorable Ray C. Jones, Chairman, Maurice Bowman, Vice-Chairman, and William Cartwright, Commissioner, sitting.

[illegible], Attorney, appeared for the applicant, Singer Oil Operating Company; [illegible] Attorney, appeared for Phillips Petroleum Company; Joe A. Owens appeared for Gulf Oil Company; William J. Lee appeared for Cities Service Oil Company; [illegible] appeared for Amerada Petroleum Corporation; Earl Tunstall appeared for Core Engineering Corporation; A. J. McCready appeared for Socony Mobil Oil Company; Norman H. Rogers, Conservation Attorney, and Rell Rhodes Fisher, Assistant Conservation Attorney, appeared for the Commission.

The case was called and referred to Ralph L. Wampler, Trial Examiner, for the purpose of taking testimony and reporting to the Commission.

The Trial Examiner proceeded to hear said cause and filed his report recommending that the application be granted; that time was allowed within which exception might be filed to said report, and none having been filed, the report is hereby adopted and the Commission therefore finds as follows:

FINDINGS

1. That this is the application of Singer Oil Company for an order amending the Commission's General Rules as set out in Order No. 44297 so as to permit the use of a choke assembly dual and multiple completions.

2. That the Commission has jurisdiction over the subject matter herein; that notice has been given in all respects as required by law and no protests have been entered to the granting of the application.

3. That the applicant has an interest in the production of oil and gas in Oklahoma and proposes to use the Cole Check Assembly in Oklahoma, if authorized to do so. The subject of this hearing is a new choke assembly whereby the production from each zone in a given well is calculated by providing individual chokes for each zone. Each producing zone is tested individually in order to determine the correct orifice for each zone, then the production from each zone is commingled in the well bore. When the hydrocarbons reach the surface, each producing zone is allocated a portion of the production, which is based on tests conducted on each zone prior to the commingling. Rather than run separate tubing to each zone, the hydrocarbons are commingled and the production from each zone is calculated and assigned accordingly.

4. To permit the use of this choke assembly would require the amendment of Sections 310 and 311 of Order No. 44297. Section 310 specifically prohibits the commingling of the production in the well and sets out how the production from each zone shall be measured. Section 311 provides that gas may be used for the artificial lifting of oil where all such gas returned to the surface with the oil is lawfully used, but where the returned gas is not to be so utilized, the use of gas for artificial lifting of oil is prohibited unless otherwise ordered by the Commission. The commingling of the production in the well would possibly result in the gas from one zone lifting the production of oil from the other zone and therefore an exception would need to be made which would permit this use of the gas even though there is no market for the gas.

5. The use of this choke assembly would result in substantial savings in that it would save the running of separate tubings to each of the producing formations. The amount of the savings would vary, depending on, among other things, the depth of the productive formations.

6. All the witnesses at the hearing supported this application with the exception of [illegible] who filed a statement which, in [illegible] that the dual choke assembly may be beneficial but had definite limitations [illegible] a hearing should be held in each case if the Commission authorized [illegible].

7. Whether or not this choke assembly should be used, would depend [illegible]. Nothing in this record would show anything but that the [illegible]. Any discrepancy would arise from the calculations made by [illegible] allocating the production to each zone from the commingled production from [illegible]. There is little question but that the production from a weak zone could [illegible] by the production from a stronger zone by merely adjusting the allocation [illegible], or any number of other ways. It is presumed, however, that all operators [illegible] honest report of production. The use of the choke assembly will not [illegible] honesty or dishonesty of anyone.

8. It is in the interest of securing the greatest ultimate recovery of oil and gas from the pool, the prevention of waste and the protection of correlative rights, this application should be granted.

O R D E R

IT IS THEREFORE ORDERED by the Corporation Commission of Oklahoma that Section 310 of Order No. 44297 be amended so as to read as follows:

"310. CONTROL OF MULTIPLE COMPLETED WELLS

(a) Every multiple completed well shall be equipped, operated, produced and maintained so that there will be no commingling of the production from said formations in the well except as hereafter provided, and the production from each of said formations shall be either measured by a positive displacement dump-type continuous-flow measuring device or a measuring device authorized by the Commission after notice and hearing, and separately reported as required by the Commission, or shall be separately stored and measured on the lease in such a manner that the pipe line company or purchaser can separately identify the production from each of said formations and separately report the same to the Conservation Department of the Commission.

(b) Where permitted by the Commission upon notice and hearing for each individual well, the production from each formation may be produced through a multiple choke assembly so designed and located in the well bore as to segregate the formations, preventing commingling within the formations, but permitting commingling in the tubing string through individual choke orifices. The commingled production shall be separately measured at the surface and allocated to each formation on the basis of tests using the orifice principle of measurement.

(c) Upon request by the Director of Conservation, any multiple completed well shall be tested at any time to demonstrate the effectiveness of the separation of sources of supply, such tests to be witnessed by representatives of the Commission and by offset operators if desired."

IT IS FURTHER ORDERED that Section 311 of Order No. 44297 be amended so as to read as follows:

"311. USE OF GAS OR ARTIFICIAL LIFTING

(a) Gas may be used for the artificial lifting of oil where all such gas returned to the surface with the oil is lawfully used. Where the returned gas is [illegible] the use of gas for artificial lifting of oil is prohibited, [illegible] specifically ordered by the Commission upon hearing.

(b) The use of production from one common source of supply to assist in lifting the production from another common source of supply by commingling the production from both common sources of supply in the tubing string shall be permitted in those instances in which the operator is otherwise authorized to so commingle the production in the tubing."

It is hereby ordered that the following testing procedure be followed in all cases where the multi flow choke assembly is used:

1. Procure the necessary information to calculate the correct size of the flow beans for each outlet in the assembly.

2. Install the orifice assembly with one side blanked off and the other side with a flow bean of the calculated size.

3. Run a production test for 24 hours at stabilized rate of flow measuring all fluids and gases produced.

4. Pull the choke assembly and place the correct size orifices in both sides and replace choke assembly.

5. Run a production test at a stabilized rate for 24 hours.

6. Calculate production from each zone on the basis of production from both zones less production from the individual zone.

7. At six month intervals repeat the testing procedure and run bottom hole pressures by:

(1) Removing the orifice assembly and blanking one side and taking a 24 hour bottom hole pressure test.

(2) Remove the assembly, blank the other side and take the 24 hour bottom hole pressure test.

8. Orifices will be sized so that the well will not produce at a rate in excess of 1.3 times the current allowables.

9. Orifices will be sized so that no zone will produce in excess of established field gas oil ratios.

10. Data will be furnished the Commission on forms approved by the Commission."

DONE AND PERFORMED this 31st day of January, 19 64.

CORPORATION COMMISSION OF OKLAHOMA

Roy C. Jones, Chairman

Harold Freeman, Vice-Chairman

Wilburn Cartwright, Commissioner

ATTEST: Secretary

Secretary

STATE OF LOUISIANA
DEPARTMENT OF CONSERVATION
BATON ROUGE, LOUISIANA

June 20, 1961

ORDER NO. 541-I

Order concerning the application of Sun Oil Company for an exception to the provisions of Department of Conservation Statewide Order No. 29-B, dated July 19, 1943, in the Kinder Field, Allen Parish, Louisiana.

* *

Pursuant to power delegated under the laws of the State of Louisiana, and particularly Title 30 of Louisiana Revised Statutes of 1950, and after public hearing held under Docket No. 61-192 in Baton Rouge, Louisiana, on May 25, 1961, upon the application of Sun Oil Company, following legal publication of notice and notice by mail to all known interested parties in accordance with the rules prescribed by the Commissioner of Conservation, the following order is issued and promulgated by the Commissioner of Conservation as being reasonably necessary to conserve the oil and gas resources of the State, to prevent waste as defined by law, to avoid the drilling of unnecessary wells, and otherwise to carry out the provisions of the laws of this State.

FINDINGS

The Commissioner of Conservation finds as follows:

1. That a reasonable interpretation of all available engineering data indicates that the use of a multiple completion choke assembly will permit the production of gaseous and/or liquid hydrocarbons from two separate reservoirs simultaneously through the same tubing without communication existing between such zones of production utilizing energy dissipated in producing production from one zone to lift production from another zone.

2. That a reasonable interpretation of all engineering data indicates that the use of the multiple completion choke assembly should permit a definite measurement of production from two separate reservoirs and the resulting proper allocation of both gaseous and/or liquid hydrocarbons.

3. That the use of the multiple completion choke assembly will permit a greater ultimate recovery from the producing zones, thereby preventing waste and increasing the just and equitable share of recoverable hydrocarbons and the resulting greater income to each owner of an interest in said producing zones.

4. That an exception to Statewide Order No. 29-B, and in particular Section X, Paragraph E, sub-paragraph 1, and Section XI, Paragraph B, sub-paragraph 4, should be granted to permit the use of such multiple completion choke assembly in the following wells situated in the Kinder Field, Allen Parish, Louisiana, to-wit: Unkel Well No. 1-D and Vicksburg Unit Well No. 3; Vicksburg Unit Well No. 1 and Lawrence-Chachere Unit Well No. 1-D; Vicksburg Unit Well No. 2 and Chachere Unit B, Well No. 1-D; Vicksburg Unit No. 4 and Kinder Canal Co. "A" Well No. 2-D; and Vicksburg Unit No. 5 and Herman M. Houston Well No. 3-D.

5. That permission to use the multiple completion choke assembly in wells dually completed by Sun Oil Company in the Kinder Field, Allen Parish, Louisiana, subsequent to this Order can be granted, without the necessity of a public hearing, under the provisions of this Order and applicable provisions of Statewide Order No. 29-D, as amended and supplemented, following proper notice to all parties at interest who were not parties to this hearing.

O R D E R

NOW, THEREFORE, IT IS ORDERED THAT:

1. The Applicant, Sun Oil Company, be and is hereby granted an exception to Statewide Order No. 29-B, and particularly Section X, Paragraph E, sub-paragraph 1, and Section XI, Paragraph B, sub-paragraph 4, to permit the continued use of the multiple completion choke assembly in the Unkel Well No. 1-D and Vicksburg Unit Well No. 3.

2. The Applicant, Sun Oil Company, is further hereby granted an exception to Statewide Order No. 29-B, and particularly Section X, Paragraph E, sub-paragraph 1, and Section XI, Paragraph B, sub-paragraph 4, to permit, install and use the multiple completion choke assembly in producing Vicksburg Unit Well No. 1 and Lawrence-Chachere Unit Well No. 1-D, Vicksburg Unit Well No. 2 and Chachere Unit B, Well No. 1-D; Vicksburg Unit No. 4 and Kinder Canal Co. "A" Well No. 2-D; and Vicksburg Unit No. 5 and Sherman M. Houston Well No. 3-D, when such wells are dually completed in accordance with applicable rules and regulations.

3. The Applicant, Sun Oil Company, is hereby granted permission to commingle gaseous and/or liquid hydrocarbons from two separate reservoirs in the same tubing through the use of the multiple completion choke assembly and to subsequently measure such production and properly allocate both gaseous and/or liquid hydrocarbons to each separate reservoir. The rate of production of both gaseous and/or liquid hydrocarbons from each separate reservoir through the use of such multiple completion choke assembly shall be established by the following procedure:

A. Pull the orifice head assembly of the multiple completion choke.

B. Install a blank choke bean in the orifice head assembly to close in the zone with the lower pressure.

C. Run the orifice head assembly.

D. Allow the higher pressure well to flow until the rate of flow is stabilized. Obtain twenty-four-hour measurement of gaseous and/or liquid hydrocarbons by means of tank gauges and orifice meter.

E. Pull the orifice head assembly.

F. Replace the blank choke bean with a choke bean sized to regulate the production from the weaker zone to its allowed rate. The choke used during the preceding test to control the rate from the higher pressure zone remains in the orifice head.

G. Re-run the orifice head assembly.

H. Measure the total gaseous and the total liquid hydrocarbons using tank gauges and orifice meter.

I. Deduct from the quantities determined by (H) the gaseous and/or liquid hydrocarbons previously determined by test of the higher pressure zone. The difference is that produced by the weaker zone.

Production tests shall be made and reported to the District Manager in accordance with the provisions of Statewide Order 29-B, Section XI, Paragraph D. Applicant will provide individual separating and measurement facilities for each dual completion.

4. The Applicant, Sun Oil Company, shall be granted permission, without the necessity of a public hearing, to use the multiple completion choke assembly in wells completed from two separate reservoirs in the Kinder Field, Allen Parish, Louisiana, under the applicable provisions of this order, and compliance with the applicable provisions of Statewide Order No. 29-D, as amended and supplemented, and following proper notice to all parties at interest who were not parties to the hearing for which this order is issued.

This Order shall be effective on and after June 1, 1961.

DEPARTMENT OF CONSERVATION
OF THE STATE OF LOUISIANA

James H. Gill

JAMES H. GILL
COMMISSIONER OF CONSERVATION

CVH/lwh-6/20/61

STATE OF LOUISIANA
DEPARTMENT OF CONSERVATION
BATON ROUGE, LOUISIANA

April 17, 1963

ORDER NO. 576-1

Order concerning the application of Sun Oil Company for an exception to the provisions of Department of Conservation Statewide Order No. 29-B, dated July 19, 1943, in the Belle Isle Field, St. Mary Parish, Louisiana.

* *

Pursuant to power delegated under the laws of the State of Louisiana, and particularly Title 30 of Louisiana Revised Statutes of 1950, and after public hearing held under Docket No. 63-90 in New Orleans, Louisiana, on March 8, 1963, upon the application of Sun Oil Company, following legal publication of notice and notice by mail to all known interested parties in accordance with the rules prescribed by the Commissioner of Conservation, the following order is issued and promulgated by the Commissioner of Conservation as being reasonably necessary to conserve the oil and gas resources of the State, to prevent waste as defined by law, to avoid the drilling of unnecessary wells, and otherwise to carry out the provisions of the laws of this State.

FINDINGS

The Commissioner of Conservation finds as follows:

1. That a reasonable interpretation of all available engineering data indicates that the use of a multiple completion choke assembly will permit the production of gaseous and/or liquid hydrocarbons from two separate reservoirs simultaneoulsy through the same tubing without communication existing between such zones of production utilizing energy dissipated in producing from one zone to lift production from another zone.

2. That a reasonable interpretation of all engineering data indicates that the use of the multiple completion choke assembly should permit a definite measurement of production from two separate reservoirs and the resulting proper allocation of both gaseous and/or liquid hydrocarbons.

3. That the use of the multiple completion choke assembly will permit a greater ultimate recovery from the producing zones, thereby preventing waste and increasing the just and equitable share of recoverable hydrocarbons and the resulting greater income to each owner of an interest in said producing zones.

4. That an exception to Statewide Order No. 29-B, and in particular Section X, Paragraph E, sub-paragraph 1, and Section XI, Paragraph B, sub-paragraph 4, should be granted to permit the use of such multiple completion choke assembly in the following wells situated in the Belle Isle Field, St. Mary Parish, Louisiana, to-wit: Belle Isle Unit Wells Nos. 1-56, 1-56-D, 3-5 and 3-5-D.

5. That permission to install and use the multiple completion choke assembly in wells dually completed by Sun Oil Company in the Belle Isle Field, St. Mary Parish, Louisiana, subsequent to this Order can be granted, without the necessity of a public hearing, under the provisions of this Order and applicable provisions of Statewide Order No. 29-D, as amended and supplemented, following proper notice to all parties at interest who were not parties to this hearing.

O R D E R

NOW, THEREFORE, IT IS ORDERED THAT:

1. The applicant, Sun Oil Company, be and is hereby granted an exception to Statewide Order No. 29-B, and particularly Section X, Paragraph E, sub-paragraph 1, and Section XI, Paragraph B, sub-paragraph 4, to permit the use of the multiple completion choke assembly in their Belle Isle Unit Wells Nos. 1-56, 1-56-D, 3-5 and 3-5-D, Belle Isle Field, St. Mary Parish, Louisiana.

2. The applicant, Sun Oil Company, is hereby granted permission to commingle gaseous and/or liquid hydrocarbons from two separate reservoirs in the same tubing through the use of the multiple completion choke assembly and to subsequently measure such production and properly allocate both gaseous and/or liquid hydrocarbons to each separate reservoir. The rate of production of both gaseous and/or liquid hydrocarbons from each separate reservoir through the use of such multiple completion choke assembly shall be established by the procedure as outlined in Paragraph 3 of Order No. 541-1.

3. The applicant, Sun Oil Company, shall be granted permission, without the necessity of a public hearing, to install and use the multiple completion choke assembly in wells completed from two separate reservoirs in the Belle Isle Field, St. Mary Parish, Louisiana, under the applicable provisions of this order, and compliance with the applicable provisions of Statewide Order No. 29-D, as amended and supplemented, and following proper notice to all parties at interest who were not parties to the hearing for which this order is issued.

This Order shall be effective on and after April 17, 1963.

DEPARTMENT OF CONSERVATION
OF THE STATE OF LOUISIANA

JAMES H. GILL
COMMISSIONER OF CONSERVATION

AFP/lwh-4/17/63

STATE OF LOUISIANA
DEPARTMENT OF CONSERVATION
BATON ROUGE, LOUISIANA

January 22, 1964

ORDER NO. 137-11

Order relating to the application of The California Company for exception to Statewide Order 29-B and authority to utilize the dual flow bottom hole choke assembly in its W. A. Colvin No. 1 Well and other wells in the Hico-Knowles Field, Lincoln Parish, Louisiana, as permanent installations.

* * * * * * * * * * * * * * * * * * *

Pursuant to power delegated under the laws of the State of Louisiana and particularly Title 30 of Louisiana Revised Statutes of 1950, and after a public hearing held under Docket No. 64-32 in Shreveport, Louisiana, on January 15, 1964, upon the application of The California Company, a Division of California Oil Company, following legal publication of notice and notice by mail to all known interested parties in accordance with the rules prescribed by the Commissioner of Conservation as being reasonably necessary to conserve the oil and gas resources of the State, to prevent waste as defined by law, to avoid the drilling of unnecessary wells, and otherwise to carry out the provisions of the laws of this State.

F I N D I N G S

The Commissioner of Conservation finds as follows:

1. That The California Company is the operator of the W. A. Colvin No. 1 Well in Section 32, Township 20 North, Range 3 West, Hico-Knowles Field, Lincoln Parish, Louisiana.

2. That said W. A. Colvin No. 1 Well is dually completed in the "A" Zone and the "E" Zone of the Hosston Sand with the production from each zone being owned by the same persons and/or operators in the same proportions.

3. That by letter dated November 19, 1962, the Department of Conservation approved the installation and testing of a dual flow bottom hole choke assembly in said W. A. Colvin No. 1 Well for a period of six months.

4. That data obtained by tests performed with a dual flow bottom hole choke assembly installed in said W. A. Colvin No. 1 Well, as shown on applicant's Exhibit 4 presented at the public hearing in this Docket, indicates that the use of the choke should permit a definite measurement of production from two separate reservoirs and the resulting proper allocation of the gaseous and accompanying liquid hydrocarbons.

5. That the use of a dual flow bottom hole choke assembly will permit the production of gaseous and its accompanying liquid hydrocarbons from two separate reservoirs simultaneously through the same tubing without communication existing between such zones of production, utilizing energy dissipated in producing from one zone to lift production from another zone.

6. That the use of a dual flow bottom hole choke assembly will permit a more efficient ultimate recovery from the producing zones, thereby preventing waste and increasing the recoverable hydrocarbons and resulting in greater income to each owner of an interest in the producing zones.

7. That exception to Statewide Order 29-B Section X and Section XI should be granted to permit the installation and use of the dual flow bottom hole choke assembly in the W. A. Colvin No. 1 Well as a permanent installation and authority for the installation of such choke assembly in other Hico-Knowles wells should be granted without the necessity of a public hearing, under the provisions of this Order and applicable provisions of Statewide Order 29-D as amended and supplemented, following proper notice to all parties in interest who were not parties to this hearing.

O R D E R

NOW, THEREFORE, IT IS ORDERED THAT:

1. The applicant, The California Company, a Division of California Oil Company, be and is hereby granted exception to Statewide Order 29-B and in particular Section X and Section XI thereof to permit the use of a dual flow bottom hole choke assembly in the W. A. Colvin No. 1 Well, Hico-Knowles Field, as a permanent installation.

2. The applicant be and is further granted permission to commingle gaseous and its accompanying liquid hydrocarbons from two separate reservoirs in the same tubing through the use of the dual flow bottom hole choke assembly and to subsequently measure such production and properly allocate both gaseous and its accompanying liquid hydrocarbons to each separate reservoir. The rate of production of both gaseous and its associated liquid hydrocarbons from each separate reservoir through the use of the dual flow bottom hole choke assembly shall be established by the following procedure:

A. Pull the orifice head assembly of the dual flow bottom hole choke assembly.

B. Install a blank choke bean in the orifice head assembly to close off the upper zone.

C. Rerun the orifice head assembly.

D. Allow the open formation to flow until the rate of flow is stabilized. Obtain twenty-four hour measurement of gaseous and its accompanying liquid hydrocarbons by means of an acceptable liquid measuring device and an orifice meter.

E. Pull the orifice head assembly and replace the blank choke bean with a choke bean sized to regulate the production from the zone to its allowed rate. The choke used during the preceding test to control the rate from the lower tested zone remains in the orifice head.

F. Rerun the orifice head assembly.

G. Measure the total gaseous and total liquid hydrocarbons using an acceptable liquid measuring device and an orifice meter.

H. Insure the critical flow phenomena has existed in at least one of the producing zones by interpretation of the production data obtained.

I. Deduct from the quantities determined by "G" the gaseous and its accompanying liquid hydrocarbons determined by "D". The difference is that produced by the upper zone.

Production tests shall be made and reported to the District Manager in accordance with the provisions of Statewide Order 29-D, Paragraph 4. Applicant shall provide individual separating and measurement facilities for each dual completion.

3. The applicant, The California Company, a Division of California Oil Company, be and is further granted exception to Statewide Order 29-B Section X and Section XI and permission without the necessity of a public hearing to use the dual flow bottom hole choke assembly in wells completed in any two separate reservoirs in the Hico-Knowles Field, Lincoln Parish, Louisiana, under the applicable provisions of this Order and upon compliance with other applicable provisions of Statewide Order 29-D as amended and supplemented, and following proper notice to all parties in interest who were not parties to the hearing for which this Order is issued.

This Order shall be effective on and after February 1, 1964.

DEPARTMENT OF CONSERVATION
OF THE STATE OF LOUISIANA

JAMES H. GILL
COMMISSIONER OF CONSERVATION

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STATE OF LOUISIANA
DEPARTMENT OF CONSERVATION
BATON ROUGE, LOUISIANA

April 28, 1964

ORDER NO. 218-I

Order concerning the application of Texaco Inc. to utilize multiple completion choke assembly equipment in multiply completed wells in the Cote Blanche Island Field, St. Mary Parish, Louisiana.

* *

Pursuant to power delegated under the laws of the State of Louisiana, and particularly Title 30 of Louisiana Revised Statutes of 1950. and after a public hearing held under Docket No. 64-75 in Baton Rouge, Louisiana, on February 26, 1964, upon the application of Texaco Inc., following legal publication of notice and notice by mail to all known interested parties in accordance with the rules prescribed by the Commissioner of Conservation, the following order is issued and promulgated by the Commissioner of Conservation as being reasonably necessary to conserve the oil and gas resources of the State, to prevent waste as defined by law, to avoid the drilling of unnecessary wells, and otherwise to carry out the provisions of the laws of this State.

FINDINGS

The Commissioner of Conservation finds as follows:

1. That a reasonable interpretation of all available engineering data indicates that the use of a multiple completion choke assembly will permit the production of gas and liquid hydrocarbons from two separate zones simultaneously through the same tubing without communication existing between such zones of production.

2. That a reasonable interpretation of all engineering data indicates that the use of the multiple completion choke assembly should permit a definite measurement of production from two separate zones and the resulting proper allocation of the production therefrom.

3. That the use of the multiple completion choke assembly will permit a greater ultimate recovery from the producing zones, thereby preventing waste and increasing the just and equitable share of recoverable hydrocarbons and the resulting greater income to each owner of an interest in said producing zones.

4. That an exception to Statewide Order No. 29-B, and in particular Section II, Paragraph B, should be granted to Texaco Inc. to permit the use of such multiple completion choke assembly in their Cote Blanche Island Nos. 20 and 20-D Wells in the Cote Blanche Island Field, St. Mary Parish, Louisiana.

5. That permission to use the multiple completion choke assembly in other wells dually completed by Texaco Inc. in the Cote Blanche Island Field, St. Mary Parish, Louisiana, subsequent to this Order, should be granted without the necessity of a public hearing, under the provisions of this Order and the applicable provisions of Statewide Order No. 29-D, following proper legal notice and notice to all parties at interest who were not parties to this hearing.

ORDER

NOW, THEREFORE, IT IS ORDERED THAT:

1. The applicant, Texaco Inc., be and is hereby granted an exception to Statewide Order No. 29-B and particularly Section II, Paragraph B, to permit, install, and use the multiple completion choke assembly in their multiply completed Cote Blanche Island Nos. 20 and 20-D Wells in the Cote Blanche Island Field, St. Mary Parish, Louisiana.

2. The applicant, Texaco Inc., is hereby granted permission to commingle gas and liquid hydrocarbons from two separate zones in the designated wells, reference Paragraph 1 above, in the same tubing through the use of the multiple completion choke assembly and to be subsequently measure such commingled production and allocate both gas and liquid hydrocarbons to each separate zone in accordance with the procedure adopted and approved herein.

3. The gas and liquid hydrocarbons shall be allocated to the individual zones from which it was produced on the basis of the tubing inlet pressure and the appropriate production distribution curves, such curves being constructed for various tubing inlet pressures, various surface production choke sizes and various choke bean sizes installed in the orifice head of the multiple completion choke assembly, by the following procedure:

A. Pull the orifice head assembly of the multiple completion choke.

B. Install a blank choke bean in the orifice head assembly to close in the zone with the lower pressure.

C. Run the orifice head assembly.

D. Allow the higher pressure zone to flow until the rate of flow is stabilized. Obtain twenty-four hour measurement of gas and liquid hydrocarbons by means of tank gauges and orifice meter, and concurrently, determine a downhole tubing inlet pressure and surface production choke size.

E. Pull the orifice head assembly.

F. Replace the blank choke bean with a choke bean sized to regulate the production from the lower pressure zone to its allowed rate. The choke used during the preceding test to control the rate of production from the higher pressure zone remains in the orifice head and the surface production choke size remains unchanged.

G. Re-run the orifice head assembly.

H. Measure the total commingled gas and total commingled liquid hydrocarbons from both zones using tank gauges and orifice meters and concurrently, determine downhole tubing inlet pressure.

I. From data obtained from Steps D and H above, construct appropriate production distribution curves.

Steps A through H shall be repeated bi-monthly to check downhole chokes and to insure the accuracy of the production allocation method provided for herein, or sooner, if in the opinion of the operator the producing characteristics of the commingled stream indicates a need therefor; it being provided, however, that the Commissioner may, upon proper showing of feasibility, change the frequency of such testing without the necessity of a public hearing.

4. Production tests shall be made and reported to the appropriate District Manager in accordance with the provisions of Statewide Order No. 29-B, Section XI, Paragraph D. Applicant will provide individual separating and measurement facilities for each dual completion equipped with a multiple completion choke assembly.

5. Permission to use the multiple completion choke assembly in other similarly equipped wells dually completed by Texaco Inc. in the Cote Blanche Island Field, subsequent to this Order, may be granted in accordance with the provisions of Finding No. 5 above.

This Order shall be effective on and after May 1, 1964.

DEPARTMENT OF CONSERVATION
OF THE STATE OF LOUISIANA

JAMES H. GILL
COMMISSIONER OF CONSERVATION

AFPjr/lwh-4/28/64

The wells listed below are operated by the Gulf Coast Division of Sun Oil Company. The performance of these wells, which is described briefly, shows how the Otis Multiple Completion Choke Assembly is used to increase hydrocarbon recovery, conserve natural gas, reduce costs, and increase current income.

Vicksburg Unit #3, Kinder Field, La.

Income has increased from $2770 to $8500 per month since the installation of the M. C. tool in March, 1960. The gas-oil ratio has decreased from 54,000 to 19,600 c.f. per bbl.

Belle Isle Unit #3-5, Belle Isle Field, La.

Hydrocarbons valued at $97,000 were produced in the first year of operation from a zone which would not have been completed without use of the M. C. tool.

Belle Isle Unit #1-56, Belle Isle Field, La.

Saved approximately $42,000 in equipment costs alone as compared to a twin string dual completion.

Dishman-Lucas #1, Sour Lake Field, Texas

Comparison between conventional gas lift and use of M. C. tool:

	Conventional	M. C. Tool
Number of valves	11	1
Input gas-liquid ratio	2800	170
Gas required, MCF per day	560	34

State Lease #1336 Well #82, Peterman Lake Field, La.

Saved $25,000 in equipment costs on initial completion. The surplus gas associated with the oil from the lower zone was used to produce the "dead" upper zone from 1961 to 1964, negating use of external gas lift gas during this period.

Both zones are currently produced and will be depleted using the M. C. tool and one string of flow valves. Significantly less lift gas is required than would be necessary with a twin string completion and two sets of flow valves.

Houston Unit #3, Kinder Field, La.

Saved $15,000 in equipment costs. Upper oil zone will be fully depleted without resorting to conventional artificial lift.

Hankamer #2, Stowell Field, Texas

Producing 3 BOPD economically by means of M. C. tool. The following excerpt is from a report on this operation from Mr. W. D. Tyler, Chief Engineer, Houston District, Railroad Commission of Texas, Oil & Gas Division.

"Mr. Daryl Frederick witnessed the testing of a down-hole separation and commingling tool for Sun Oil Co., Hankamer #2 in the Stowell Field. The tool has been made by Sun Oil Co. and Otis Engineering Co., and it appears to be a very valuable piece of equipment. It is deserving of Railroad Commission consideration and will perhaps meet with Commission approval.

It has a lot of merit and can be used to a good advantage in many places. On the Hankamer #2 Well it provides a method of producing oil from a weak zone which could not be economically produced by any other known methods, therefore oil is being recovered that otherwise would never be recovered."

State Lease 2620 Well #7, Lake Pelto Field, La.

Well was completed as twin string dual. Upper zone was gas lifted to "depletion" as judged by conventional standards, i.e., to a depth of 7500' by gas lift.

Well was re-worked to single string dual using M. C. tool. Upper zone is now producing top allowable of 134 BOPD.

Installation of M. C. tool on initial completion would have resulted in the following:

1. Saving of approximately $30,000 in initial completion costs.

2. Elimination of one workover costing approximately $42,000.

3. Avoided production down time of approximately 25,200 bbls of oil from Well #7-D.

4. Eliminated the necessity of furnishing external gas lift gas at 570 MCF per day since June, 1960 (a total of 830 million cu. ft.) and attendant compression.

5. Eliminated 10 flow valves costing $2600.

6. Eliminated gas lift line costing $2400.

D. S. & B. #84, Chacahoula Field, La.

Lower zone unable to flow alone, but produces 68 BOPD and 120 BSWPD using M. C. tool. Completed in 4-1/2" casing, this well illustrates the application of M. C. tool in producing duals to depletion in slim holes.

The wells described above are representative of the results obtained through Sun Oil Company's use of the M. C. tool in Texas and Louisiana.

The tool is being used by other oil companies in Louisiana, Texas, Mississippi, Oklahoma, Mexico, Kuwait, India, and possibly elsewhere, and a test has been approved in Canada.

The Department of Conservation in Louisiana, and the Railroad Commission in Texas, after reviewing performance of the tool in a number of wells, has in each instance approved permanent use of the tool.

THE MULTIPLE COMPLETION CHOKE ASSEMBLY - A NEW PROFIT MAKING TOOL

by

J. W. Hodges
Sun Oil Company
Beaumont, Texas

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For presentation at the 15th
Annual Technical Meeting
PETROLEUM & NATURAL GAS DIVISION,
C. I. M.
May 6-8, 1964
Calgary, Alberta

The Multiple Completion Choke Assembly - A New Profit-Making Tool

Abstract

This paper describes the construction, method of operation, and field performance of the Sun Oil Company-developed Multiple Completion Choke Assembly.

This down-hole commingling tool has been in operation since March, 1960. It has been used in approximately 75 wells located in Louisiana, Texas, Mississippi, Oklahoma, Mexico, Kuwait, and India.

Sun Oil Company's Gulf Coast Division, through the use of this tool during the past four years, has saved approximately $289,000 in tubular goods, and produced approximately $282,750 worth of hydrocarbons not otherwise recoverable.

The paper reports the results of Sun Oil Company's installations and discusses the various applications and limitations of the tool.

The method of allocating production to each zone is explained.

Advantages and disadvantages in simultaneous production of two separate reservoirs through a single tubing string are enumerated.

Construction and Operation

Fig. 1 shows a well equipped to receive a multiple completion choke assembly. A retainer type packer separates the two producing zones. The upper packer is optional. A side-door choke landing nipple hookup is located in the tubing 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, as shown in Fig. 2. The outer assembly, which is run on a wire line and locked in the landing nipple, contains the check valves and packing seals which prevent flow from one zone to the other.

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. 3.

Fig. 4 is a schematic drawing which shows how the device works. Production from the lower zone enters the assembly through a slotted section, flows through a sleeve-type check valve, enters and flows through the tube of the orifice-head assembly, 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 section, through 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 segregated to this point, combine and flow to the surface.

Allocation of Production

Detailed instructions for testing and allocation of production are available in the manufacturer's "Service Manual for

Otis Type 'S' Multiple Completion Choke Assembly--Dual Flow"; in general, however, allocation is based on the results of a stabilized test of one of the zones while the other zone is blanked off. The established rate from this zone is then subtracted from the commingled rate to calculate production from the second zone.

Test procedure will depend on whether or not one of the zones is in critical flow. A stream is in critical flow when alterations in pressure downstream from an orifice do not affect the rate of flow. The critical point in a gas stream flowing through an orifice occurs when the pressure downstream from the orifice is 53% of the upstream pressure; for gas-liquid mixtures, the critical ratio is higher but should not exceed approximately 0.58.

If one of the zones is in critical flow, alterations in the tubing inlet pressure (the pressure immediately downstream from the multiple completion tool) will not change the predetermined rate from that zone, and the allocation process is simplified.

If neither zone is in critical flow, the zone with the higher pressure is tested individually at several rates in a range of tubing inlet pressures expected to occur during commingled flow. By plotting the rate versus tubing inlet pressure, a graph is obtained from which the production from the zone can be determined during commingled flow. Fig. 5 shows the results of such a test in the Kinder Field, Louisiana. This graph can be used to determine the rate from the lower zone during commingled flow. If the zone is out of critical flow, its rate is a function of the tubing inlet pressure.

The method of allocating production with the multiple completion tool is basically the same as that used in conventional

practice; i.e., determining the rate from each zone by testing, commingling the production downstream from the choke beans, and allocating the interim production between test periods on the basis of the individual tests. In either case, accurate allocation depends upon the consistency with which each zone continues to produce at its tested rate, and this is in large measure dependent upon accurate flow rate control. The tungsten carbide choke beans in the multiple completion choke assembly, being highly resistant to erosion and located below the zone of paraffin deposition (precluding plugged chokes) will provide better flow rate control than will conventional surface chokes. In Sun's wells, the orifice head has been pulled approximately 450 times, and in each instance the chokes have remained true to gauge.

Applications

The multiple completion choke assembly is not a specialty tool. It is applicable in almost any type of multiple completion. Sun Oil Company has made nineteen installations in wells ranging in depth from 3790' to 15,576' and in bottom hole pressure from 814 psi to 8173 psi.

It is applicable in multiple oil, multiple gas, and combination oil-gas wells.

It can be run on initial completion, or in the conversion of a concentric or twin string dual completion. In the latter case, when either zone becomes deficient, the tool can be installed with wire-line tools, preferably in a Type "S" side-door choke landing nipple; a hook-wall tool is available, however, if a side-door nipple has not been run.

A list of its applications follows.

1. In wells where one or both zones require artificial lift, one set of gas lift valves can be used to produce the two zones through the tool at reduced cost and greater efficiency than is possible in other types of dual completions.

2. As a means of using gas-cap gas to lift liquids from the lower part of the same sand.

3. Two multiple completion tools can be used with dual strings of tubing to produce either three, four, or five zones simultaneously.

4. The tool is compatible with slim hole multiple completions.

5. Applicable to tubingless completions and permanent type completions.

6. Can be used to produce selective completions dually.

7. Can be modified and used to inject salt water or gas into separate reservoirs with reasonably accurate allocation to each reservoir.

There are two limitations to the use of the tool: 1) where there is excessive sand production and 2) where there is insufficient reservoir energy for required production and external gas is not available for gas lift.

Table No. 1 describes the wells in which Sun has used the multiple completion choke assembly.

Advantages

The advantages in using the multiple completion choke assembly are as follows:

1. Reduction in well equipment costs. In Sun Oil Company's Belle Isle Unit #1-5, Belle Isle Field, Louisiana, approximately $42,000 was saved on equipment alone as compared to a twin string dual.

2. Increased ultimate recovery. The economy of the method has resulted in production from reservoirs which would not have been tested otherwise. For example, in Sun's Belle Isle Unit #3-5, over $97,000 worth of hydrocarbons were produced in the first year of operation from a questionable zone that would have been written off if this tool had not been available.

3. Increased daily production. The income from Sun's Vicksburg Unit #3, Kinder Field, Louisiana (the lower zone in a dual completion), has increased from $2770 per month to $8500/month since installation of the tool in March, 1960. The gas-oil ratio has decreased from 54,000 c.f. per bbl to 19,600 c.f. per bbl. See Fig. 6.

4. Reduction in workover costs (compared to multiple-string completions.)

5. Reduction in surface equipment costs. This includes heaters, separators, compressors, high pressure gas-lift lines, meters, etc.

6. Maximum use of reservoir gas. By bottom hole choking and commingling production immediately above the tool, gas breaking out of solution at this point results in the lowest possible gradient in the tubing. When a strong well is combined with a weak well in this way, the weak well can be produced at its maximum potential. This not only prevents waste; it is also quite economical to the operator, as it postpones or eliminates the need

to provide artificial lift for the weaker zone. Conventional completions, by maintaining separation of production to the surface, in this respect act contrary to the principles of conservation.

The multiple completion choke assembly is in effect a single-point injection, retrievable flow valve, utilizing gas supplied directly from the formation at maximum efficiency. To illustrate the degree of efficiency, in Sun Oil Company's Dishman-Lucas #1, Sour Lake Field, Texas, a comparison was made between this method and a conventional gas lift system. This study showed that the multiple completion tool used one-sixteenth as much gas and produced twice as much liquid.

7. Reduction in corrosion inhibitor and paraffin treatment costs.

Disadvantages

1. Cost of testing. The periodic testing required results in wire-line costs otherwise not incurred; however, there are two important considerations that should not be overlooked: (a) the future value of the money saved by virtue of using the tool. In Belle Isle Unit #1-56, the $42,000 saved in initial cost is worth $44,520 at 6% compound interest after one year, $56,205 after five years, and $75,215 at the end of ten years. Obviously, this gain in value will absorb wire-line costs (which have run from $50 per month to $150 per month in Sun's nineteen wells); (b) the use of the tool will result in an increase in production in most wells. The income from just one additional barrel of oil per day will in most instances pay the wire-line costs.

2. Somewhat more complicated (technical) method of

production accounting. The engineer in charge must practice more of his production technology than is normally required in routine production accounting. This may or may not be a disadvantage, and the bulk of the work can still be handled by the production clerk.

Attitude of the Conservation Agencies

Co-operation of the various State agencies has come about through recognition that 1) commingling down hole with the choke assembly is no different from commingling at the surface; 2) the tool is mechanically sound; 3) the tool will prevent waste and increase ultimate recovery; and 4) most of the people in the oil industry are honest. Those that aren't will find a cheaper way to produce multiple completions dishonestly.

Conclusions

Simultaneous production of two reservoirs through a single string of tubing will in many wells result in a significant reduction in completion and lifting costs and increase in current income and ultimate recovery. The Multiple Completion Choke Assembly will maintain separation of reservoirs and control the rate of production from each. Test procedures have been developed which provide an acceptable method of determining the production from each zone. All requirements imposed by the State regulatory agencies can be satisfied.

Well	Field	Depth, Ft.	Static Bottom Hole Pressure, Psi	Bbl Liquid Per Day	Gas-Oil Ratio Cu Ft Per Bbl
Unkel #1	Kinder, La.	8,067	2,575	6 Oil	22,100
		8,448	2,460	19 Cond	18,466
Miami B.S. #2	Bayou Sale, La.	14,025	5,870	20 Oil	1,000
		14,236	6,533	75 Oil, 75 SW	7,750
Houston #3	Kinder, La.	7,678	3,263	64 Oil	784
		8,379	3,371	37 Cond	19,100
B.I.U. #3-5	Belle Isle, La.	13,958	6,500	129 Oil	735
		13,983	6,500	129 Oil	945
K. C. "A" #2	Kinder, La.	7,394	3,290	7 Oil, 15 SW	643
		8,390	3,485	64 Cond	16,188
B.I.U. #1-56	Belle Isle, La.	12,840	5,670	115 Oil	906
		13,398	5,781	129 Oil	423
State Lse 1337 #22	Bateman Lake, La.	10,154	4,538	71 Oil	2,929
		11,700	5,060	65 Oil, 10 SW	3,354
Carpenter #4	Sour Lake, Texas	4,710	814	Gas	-
		4,788	1,093	14 Oil	649
State Lse 1337 #15	Bateman Lake, La.	11,749	5,335	120 Cond	29,300
		11,828	5,331	132 Oil	1,060
Dishman-Lucas #1	Sour Lake, Texas	9,610	4,340	Gas	-
		9,800	3,778	21 Oil, 325 SW	1,143

Table 1.--Sun Oil Company Wells Using Multiple Completion Tool

Well	Field	Depth, Ft.	Static Bottom Hole Pressure, Psi	Bbl Liquid Per Day	Gas-Oil Ratio Cu Ft Per Bbl
Jones #2	Conroe, Texas	3,790	1,634	Gas	-
		5,043	2,100	28 Oil, 298 SW	893
Chachere #2	Kinder, La.	6,680	3,290	Sanded Up	-
		8,062	2,300	2 Oil	54,049
Regan #2	Egan, La.	9,855	3,636	12 Cond	26,250
		10,067	3,850	121 Oil, 684 SW	995
LeBlanc Pool #1	Egan, La.	9,360	4,169	17 Cond	130,000
		9,872	4,195	48 Oil, 912 SW	1,271
Hankamer #2	Stowell, Texas	7,337	Not Meas.	10 Oil, 240 SW	2,100
		7,452	3,242	Dry Gas	-
State Lse 2620 #10	Lake Pelto, La.	15,532	8,018	196 Oil	2,200
		15,574	7,032	130 Oil	2,400
State Lse 2620 #11	Lake Pelto, La.	15,537	8,173	132 Oil	6,200
		15,576	8,099	84 Oil	4,040
Sun Fee "B" #6	Hull, Texas	9,904	5,500	100 Oil	750
		9,992	5,500	27 Oil	800
B.I.U. #1-61	Belle Isle, La.	13,478	5,441	142 Oil 37 SW	1,027
		14,392	6,500	159 Oil	1,410

Table 1 cont'd.--Sun Oil Company Wells Using Multiple Completion Tool

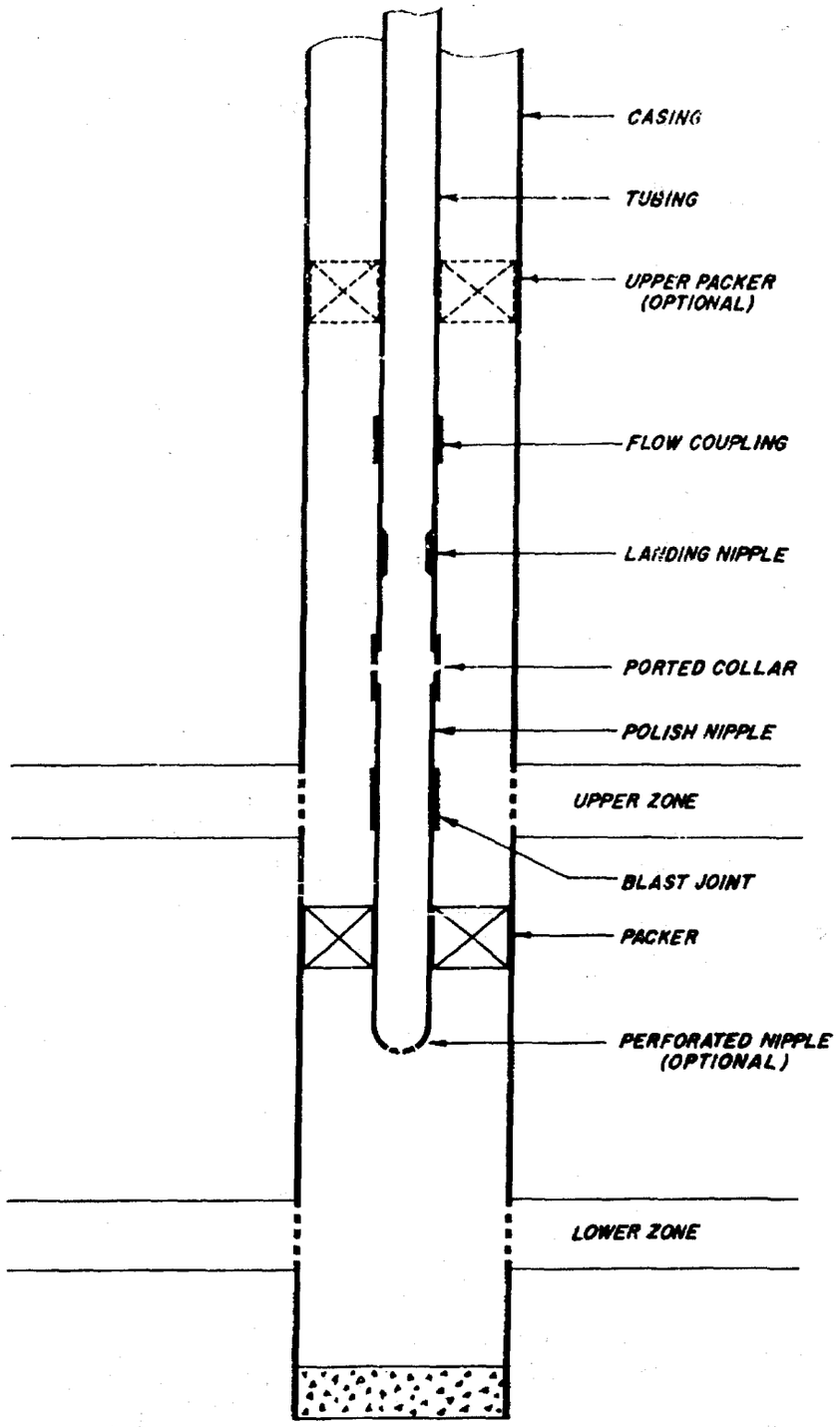


Fig. 1--Well Properly Equipped for Multiple Completion Choke Assembly

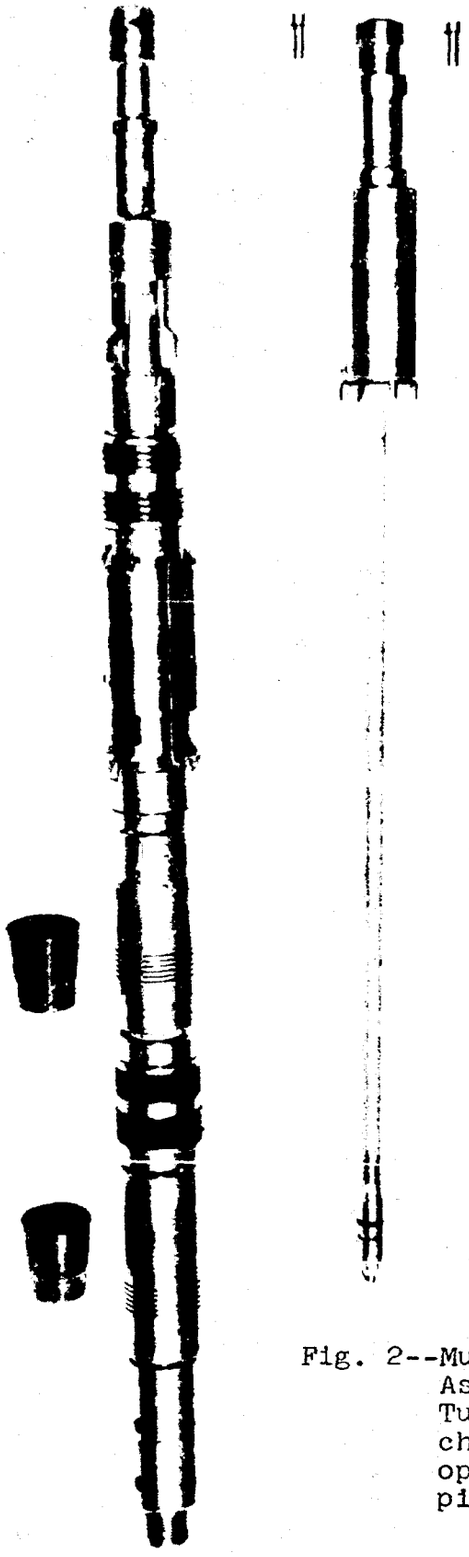


Fig. 2--Multiple Completion Assembly for 2-3/8-in. Tubing. Check valves and choke beans are shown opposite position occupied within tool.

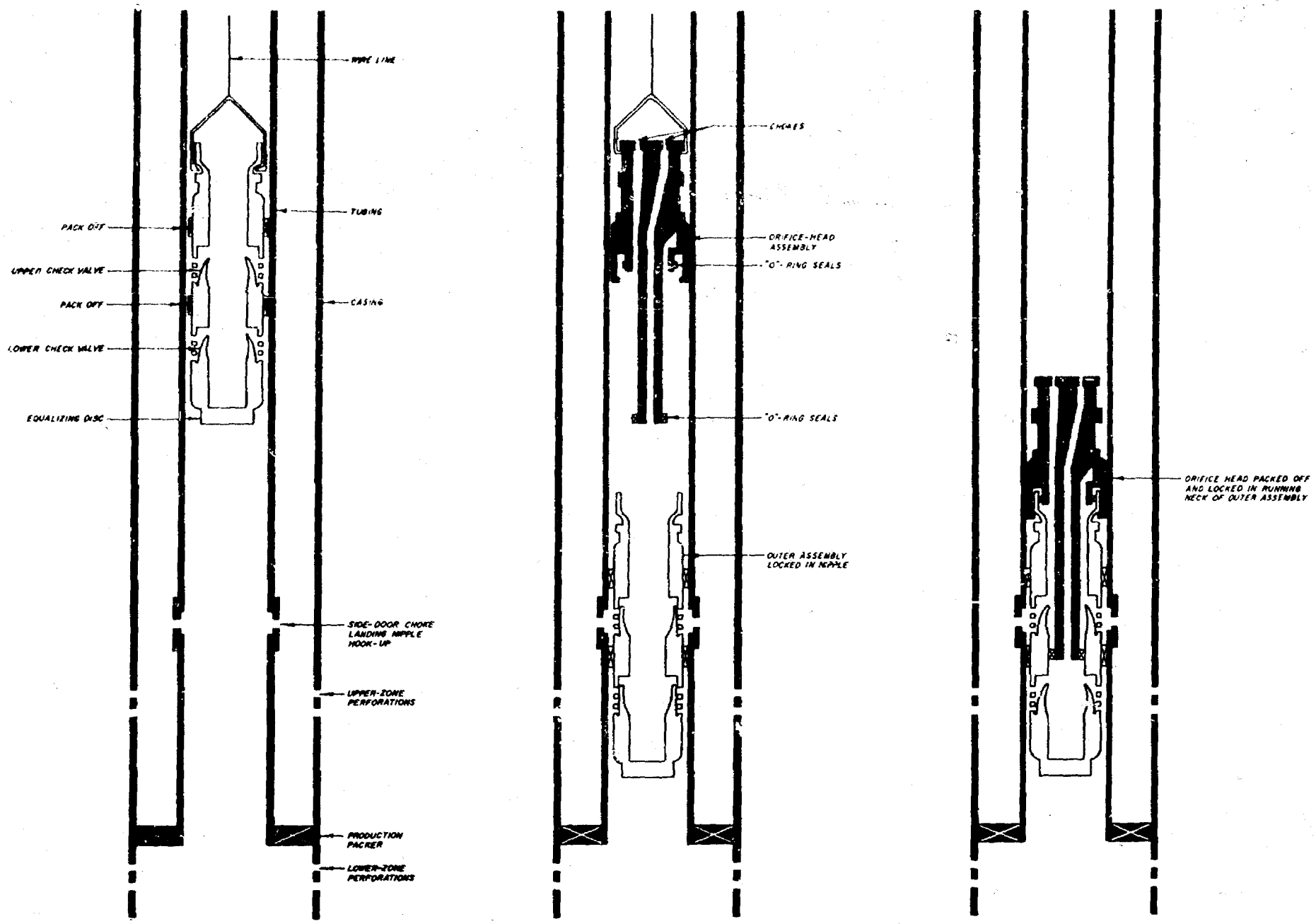


Fig. 3--Method of Running Inner and Outer Assemblies

Note in center drawing that check valves prevent inter-zone flow.

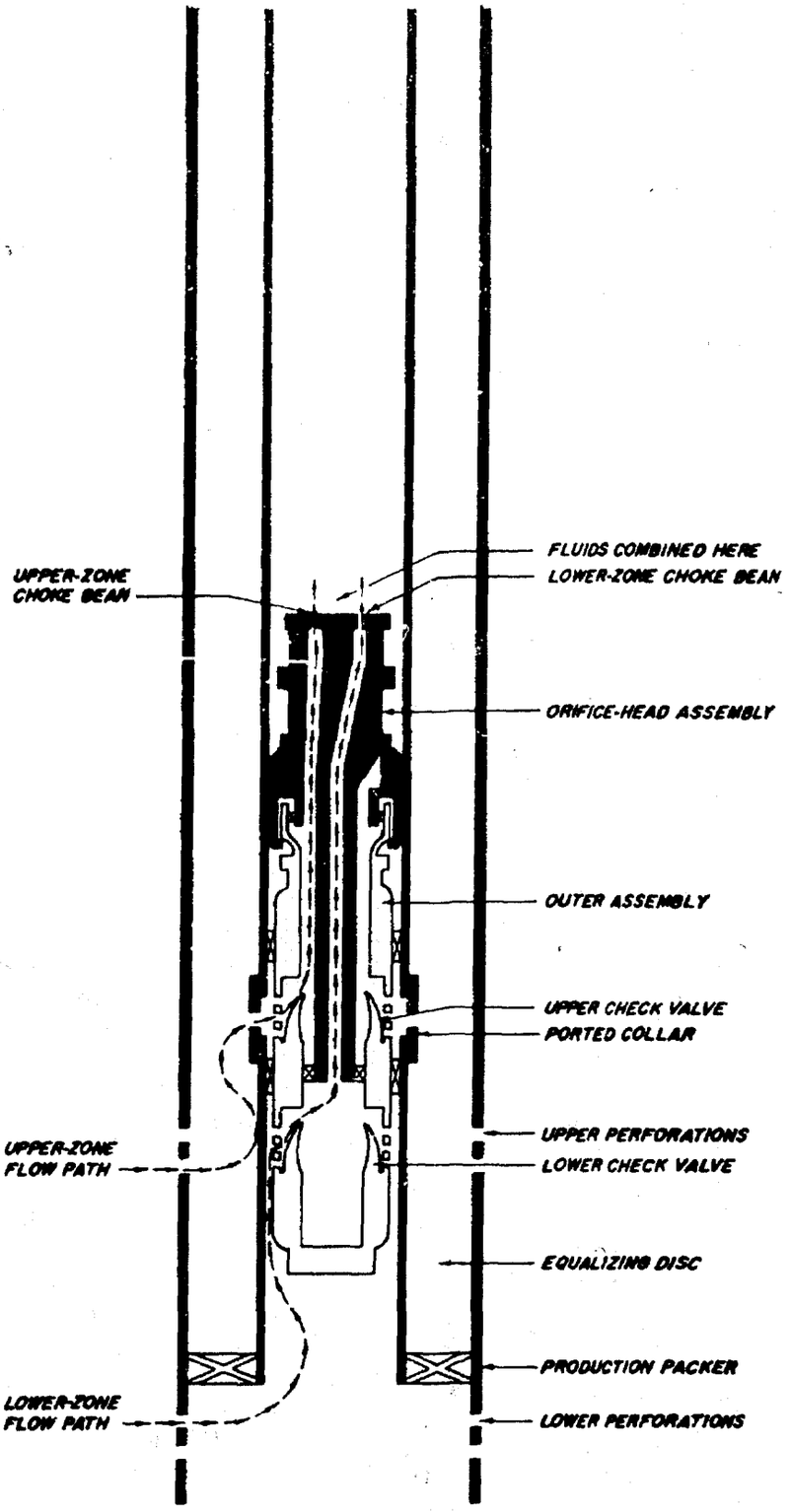


Fig. 4--Schematic Drawing Showing Operation of Multiple Completion Choke Assembly

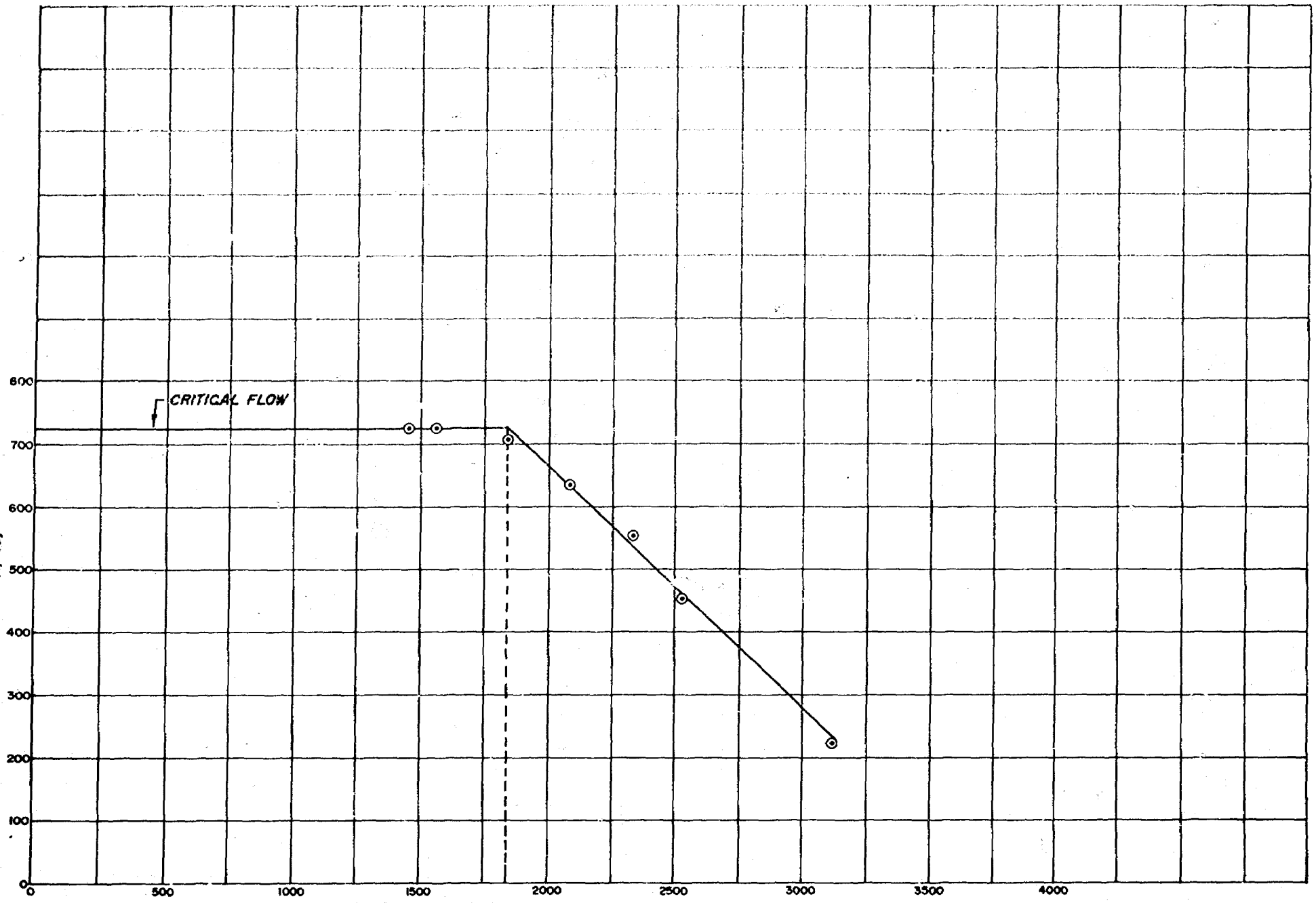


Fig. 5--Typical Allocation Test

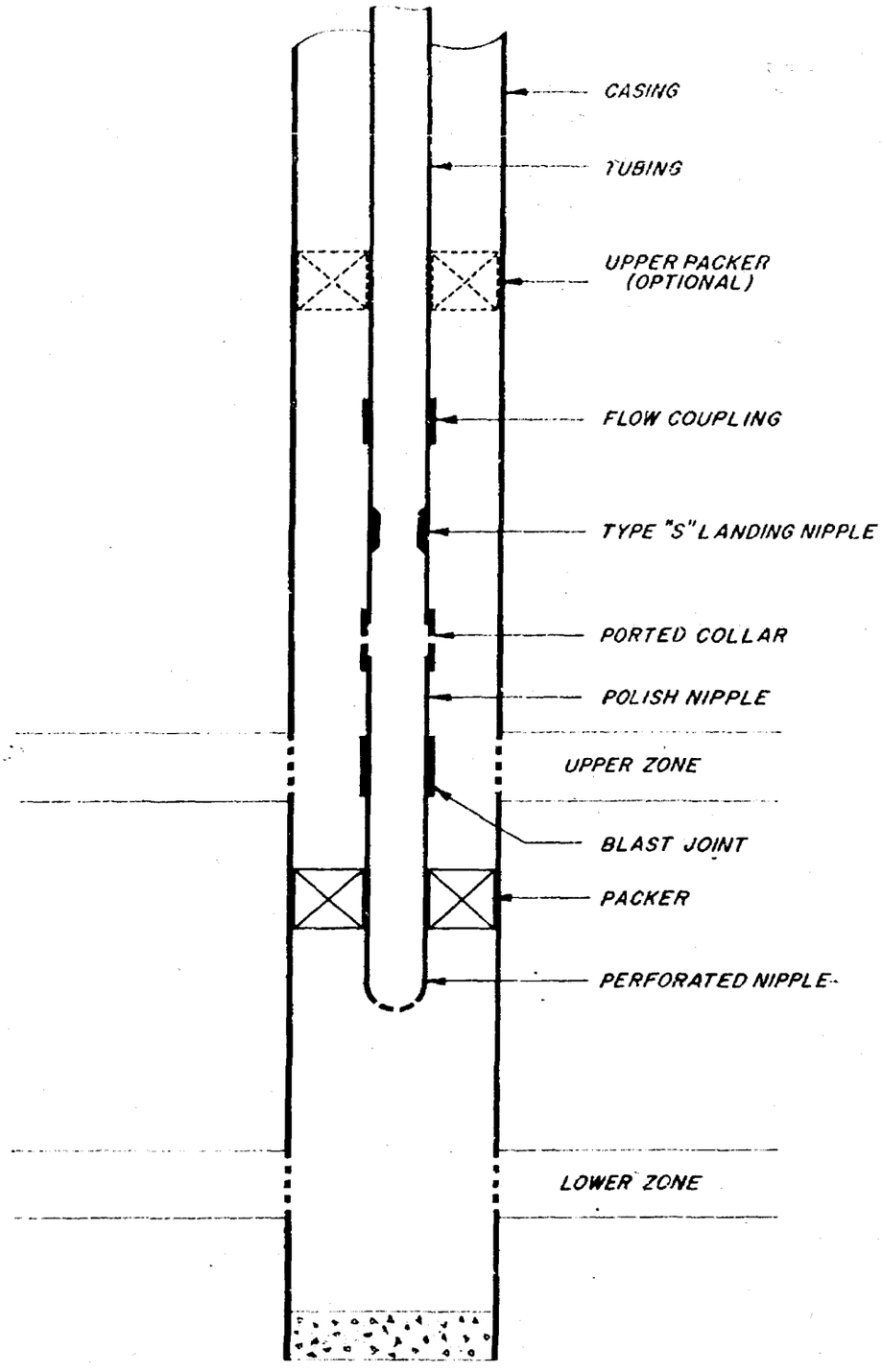
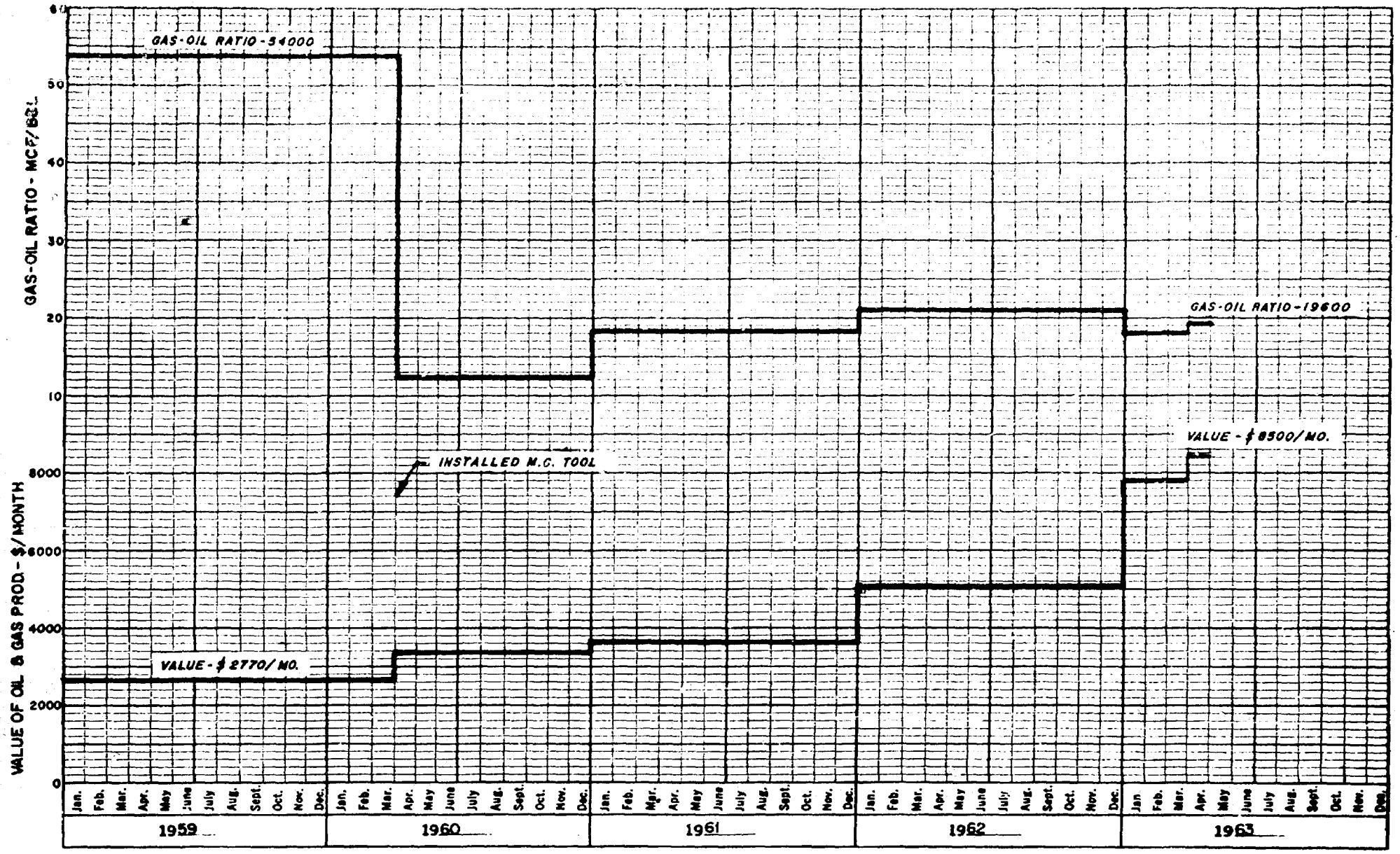


FIGURE I

WELL PROPERLY EQUIPPED FOR MULTIPLE COMPLETION CHOKE ASSEMBLY



VICKSBURG UNIT NO. 3 (LOWER ZONE)
KINDER FIELD

Fig. 6--Results of installation of Multiple Completion Choke Assembly.

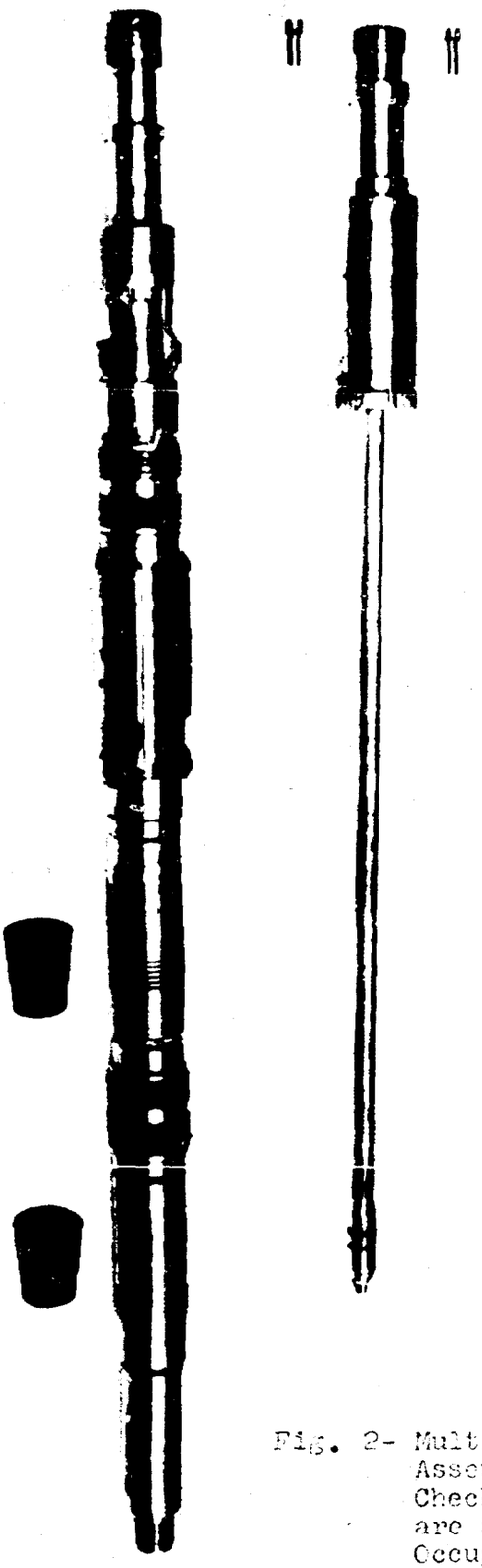


Fig. 2- Multiple Completion Choke Assembly for 2-3/8" Tubing. Check Valves and Choke Beans are Shown Opposite Position Occupied Within Tool

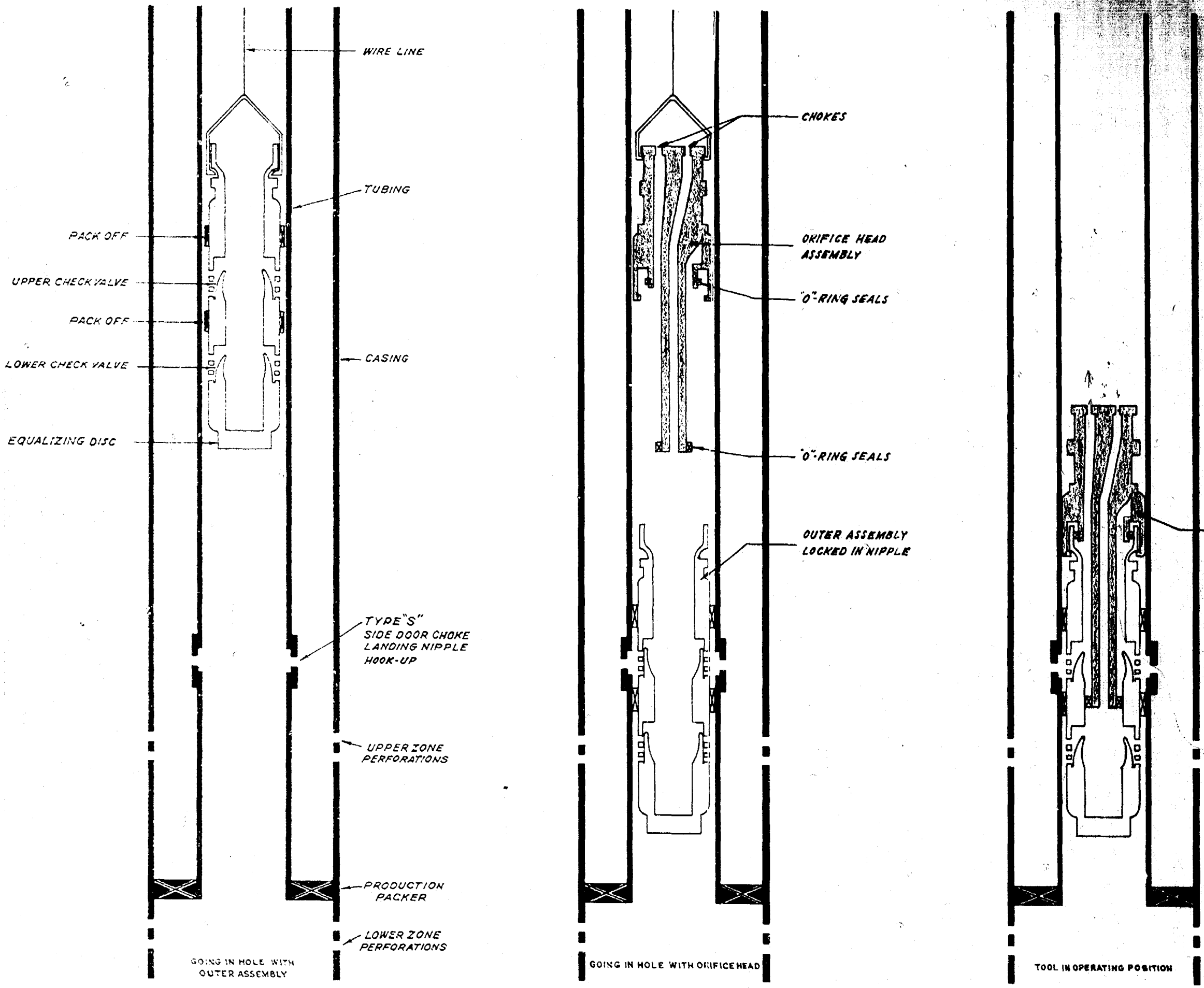


FIGURE 3

METHOD OF RUNNING INNER AND OUTER ASSEMBLIES

NOTE IN CENTER DRAWING THAT CHECK VALVES PREVENT INTER-ZONE FLOW.

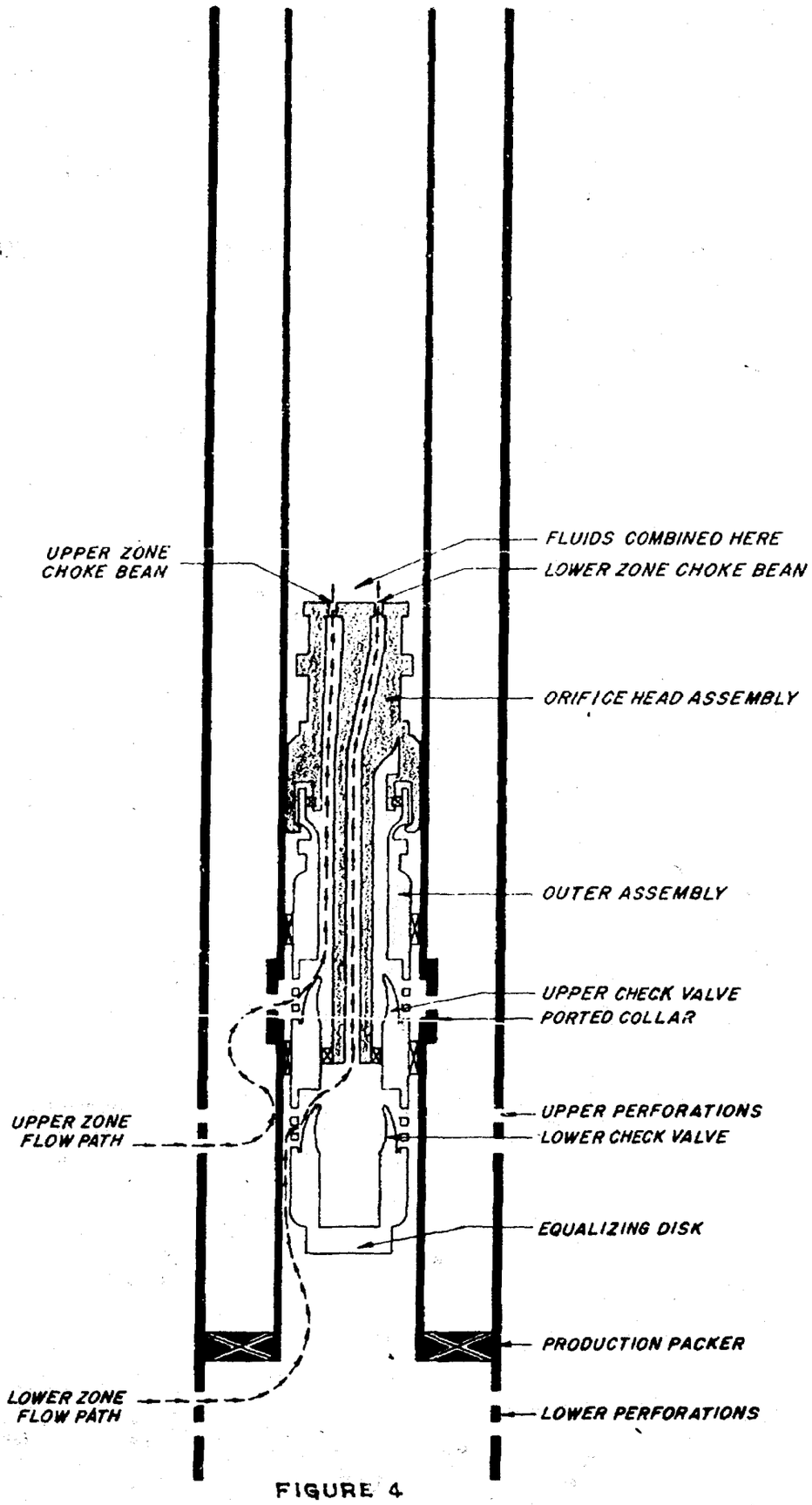

UPPER ZONE CHOKE BEAN
FLUIDS COMBINED HERE
LOWER ZONE CHOKE BEAN
ORIFICE HEAD ASSEMBLY
OUTER ASSEMBLY
UPPER CHECK VALVE
PORTED COLLAR
UPPER ZONE FLOW PATH
UPPER PERFORATIONS
LOWER CHECK VALVE
EQUALIZING DISK
PRODUCTION PACKER
LOWER ZONE FLOW PATH
LOWER PERFORATIONS

FIGURE 4



FIGURE 5
GAS FLOW THROUGH AN ORIFICE.
FLOW BECOMES CRITICAL WHEN $P_2/P_1 = .53$

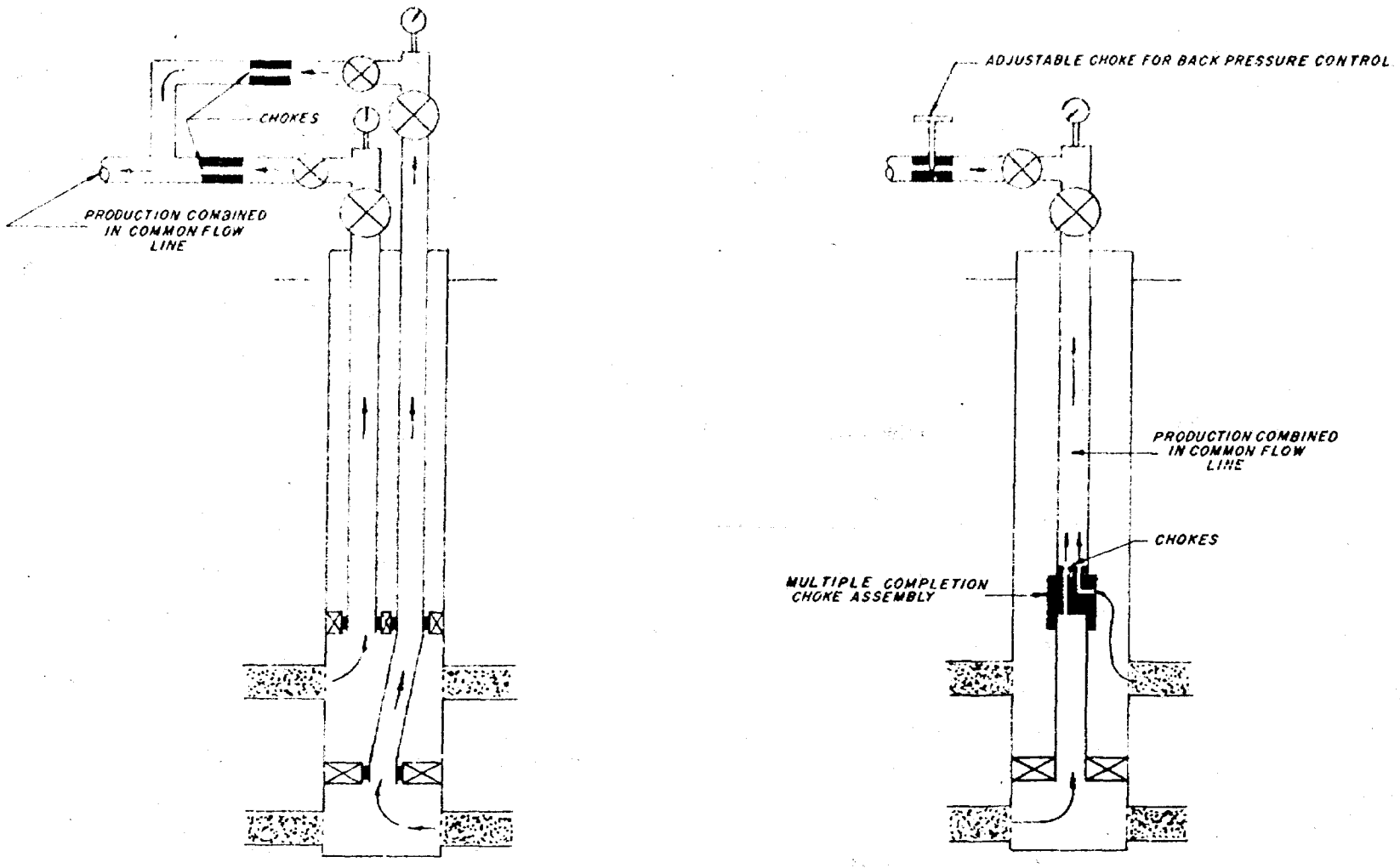


FIGURE 6
SIMILARITY BETWEEN TWIN STRING DUAL
AND
WELL EQUIPPED WITH MULTIPLE COMPLETION CHOKE ASSEMBLY

Fig. 7 Correlation of Surface and Tubing Inlet Pressures

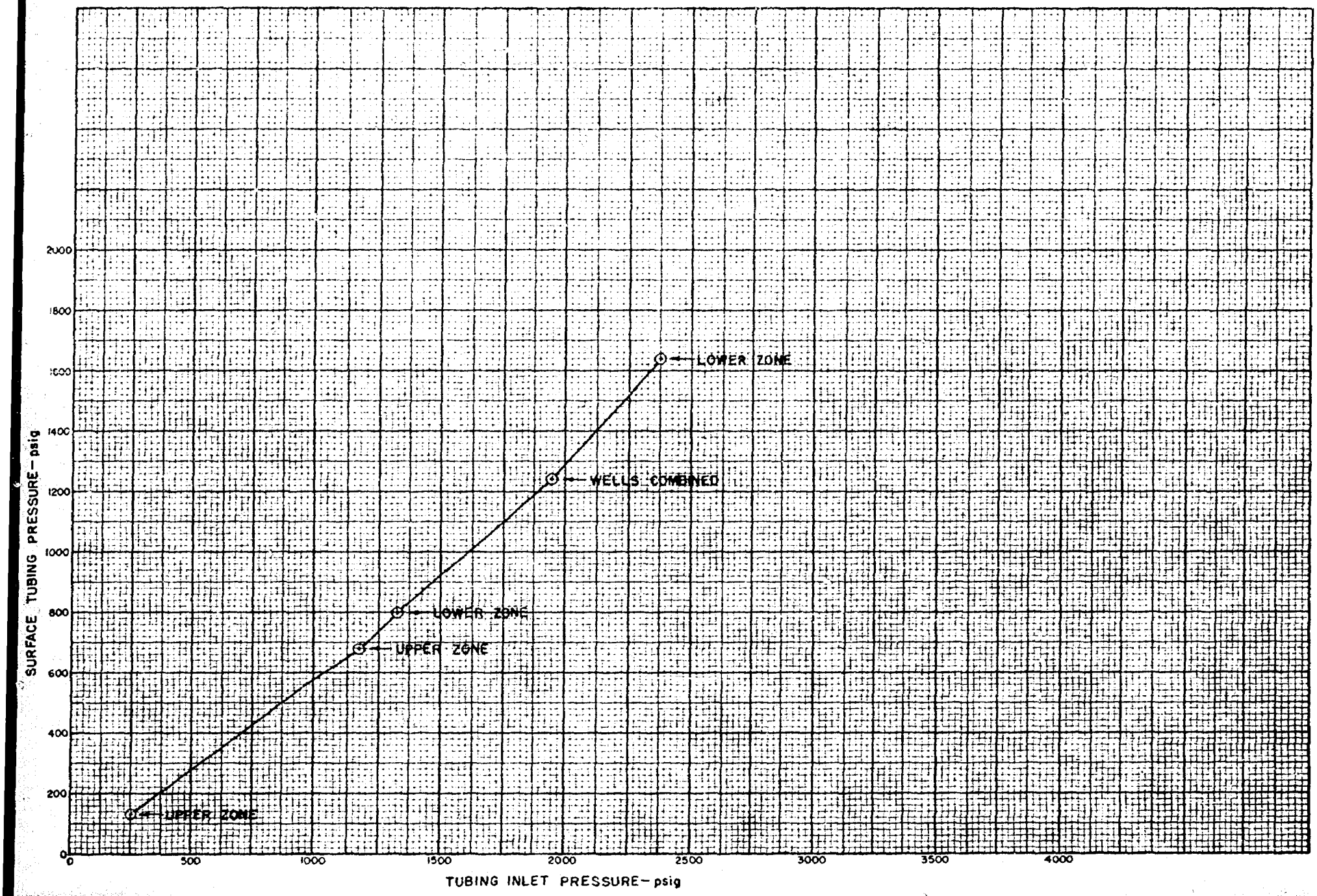


Fig. 8 Individual Test Data for Lower Zone, Well No. 3. Upper Zone Blanked Off

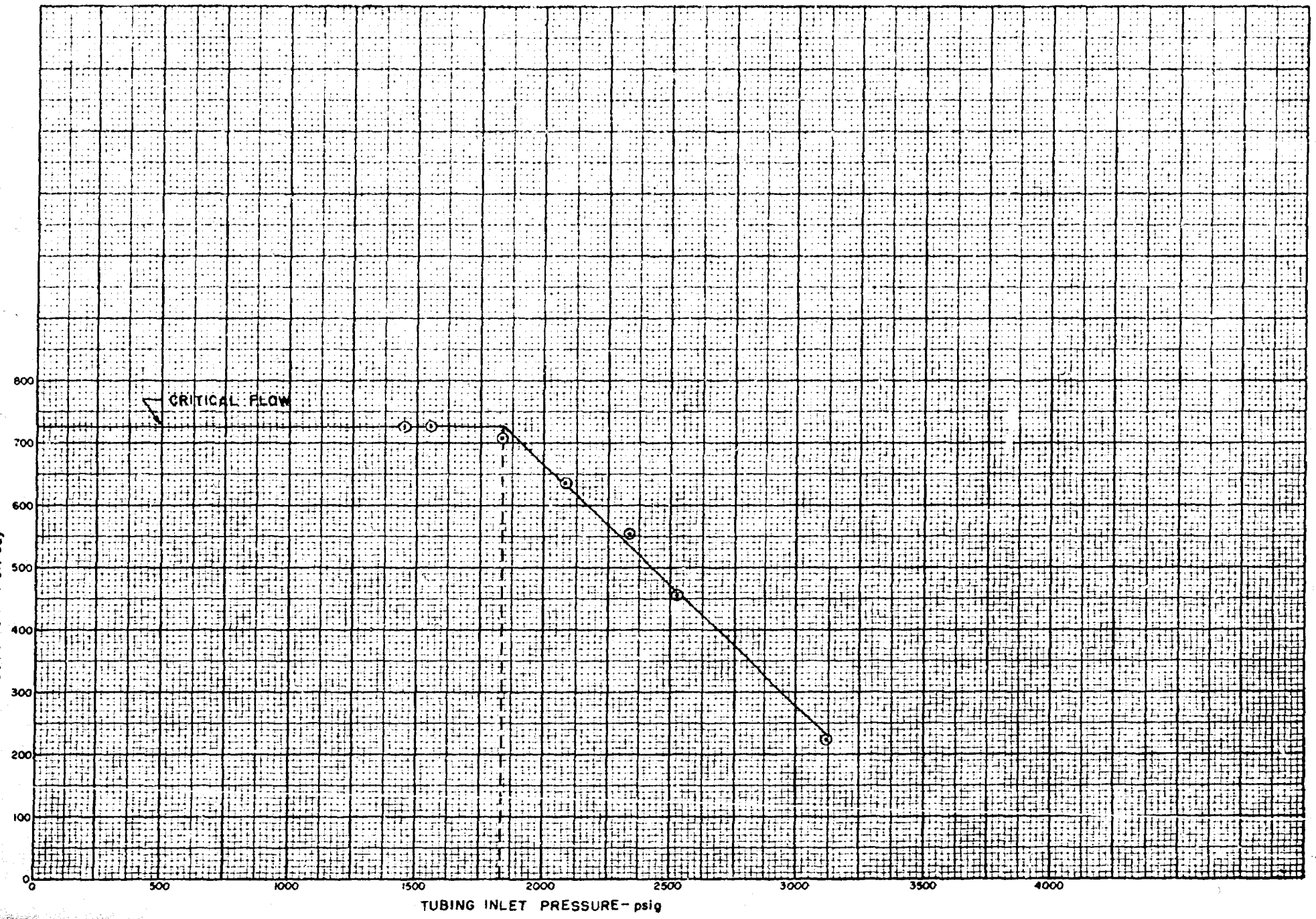
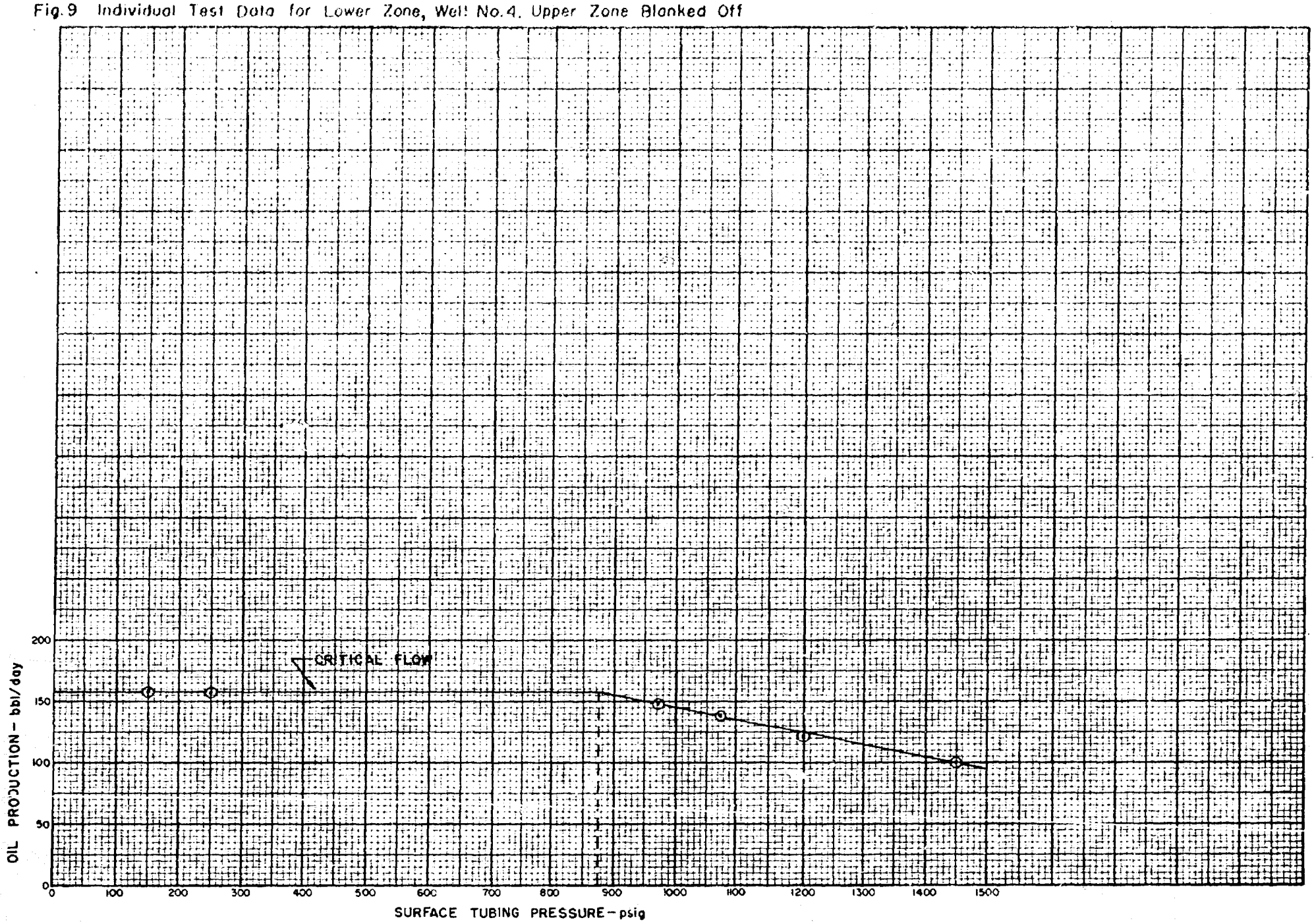


Fig. 9 Individual Test Data for Lower Zone, Well No. 4, Upper Zone Blanked Off



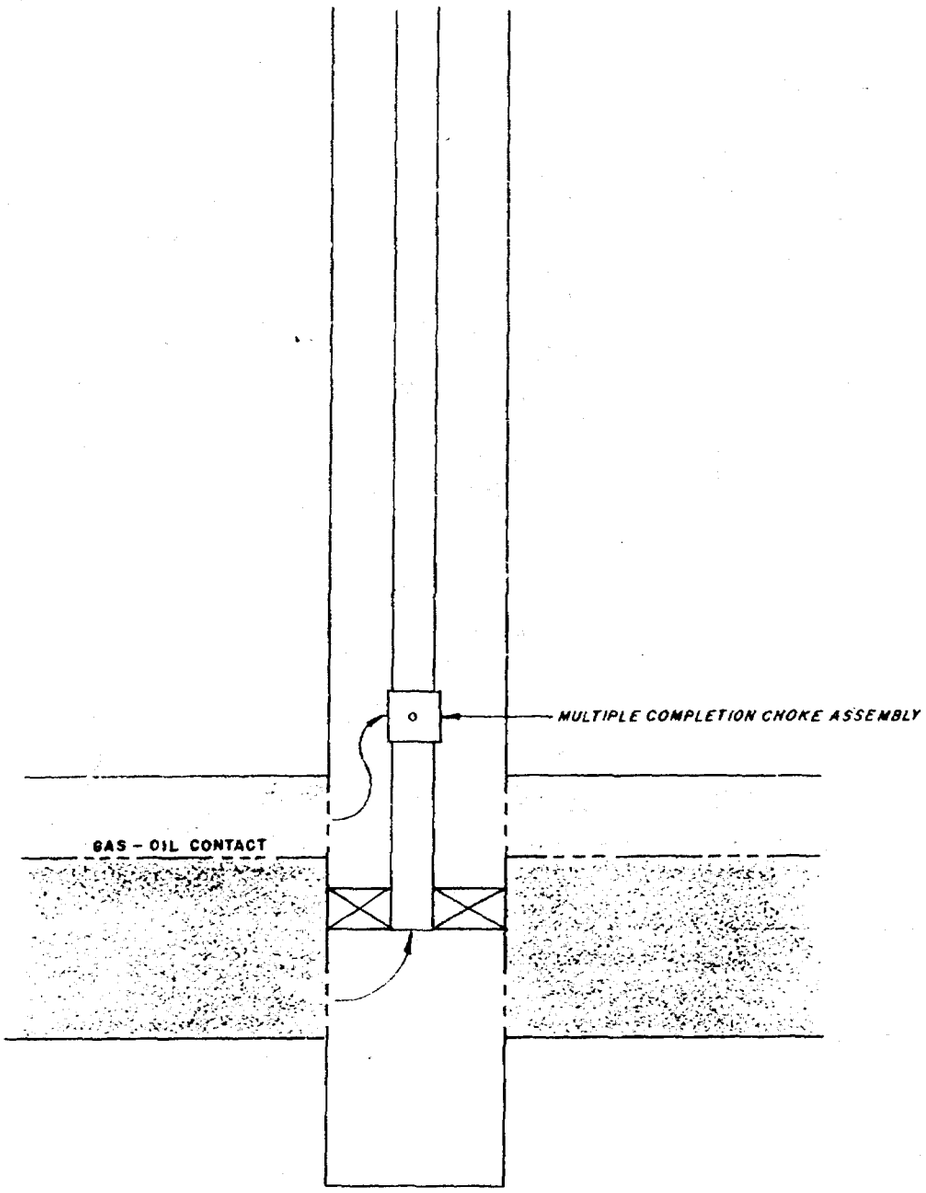


FIGURE 10

GAS LIFTING LOWER SECTION OF SINGLE ZONE WELL WITH GAS CAP

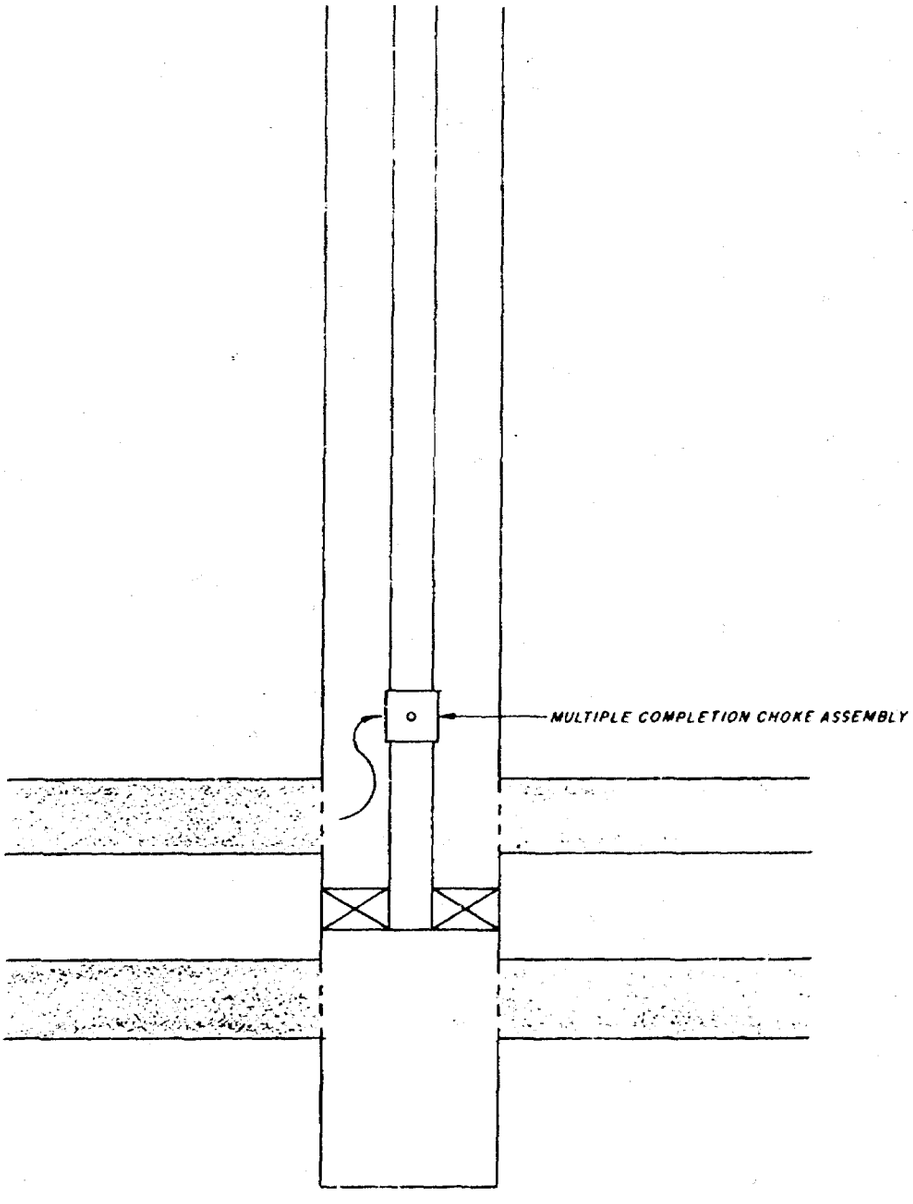


FIGURE II

ALLOWABLE OF LOWER ZONE TRANSFERRED. UPPER ZONE PRODUCED THROUGH TUBING WITH LOWER ZONE BLANKED OFF.
PERIODIC TESTS OF LOWER ZONE MADE BY LIFTING WITH UPPER.

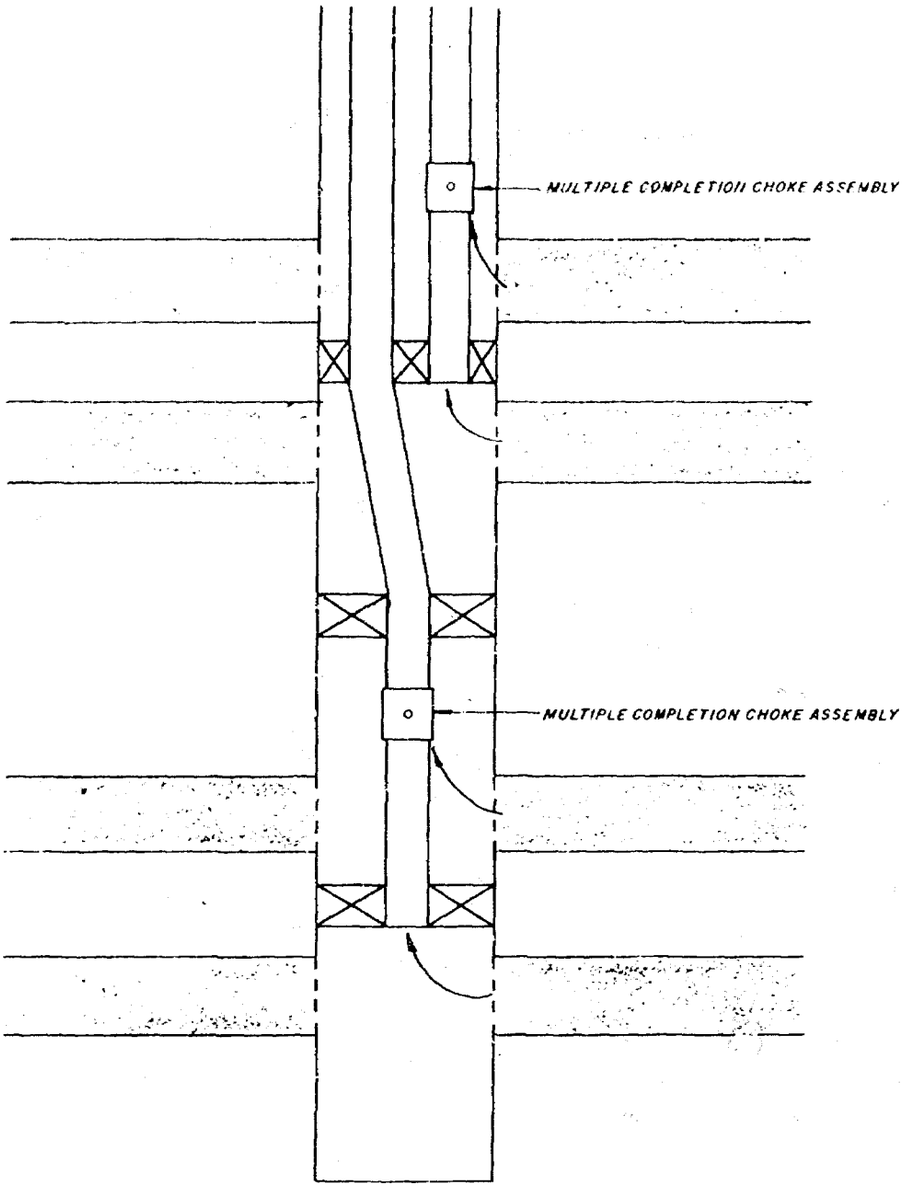


FIGURE 12
TWO STRING QUADRUPLE COMPLETION.

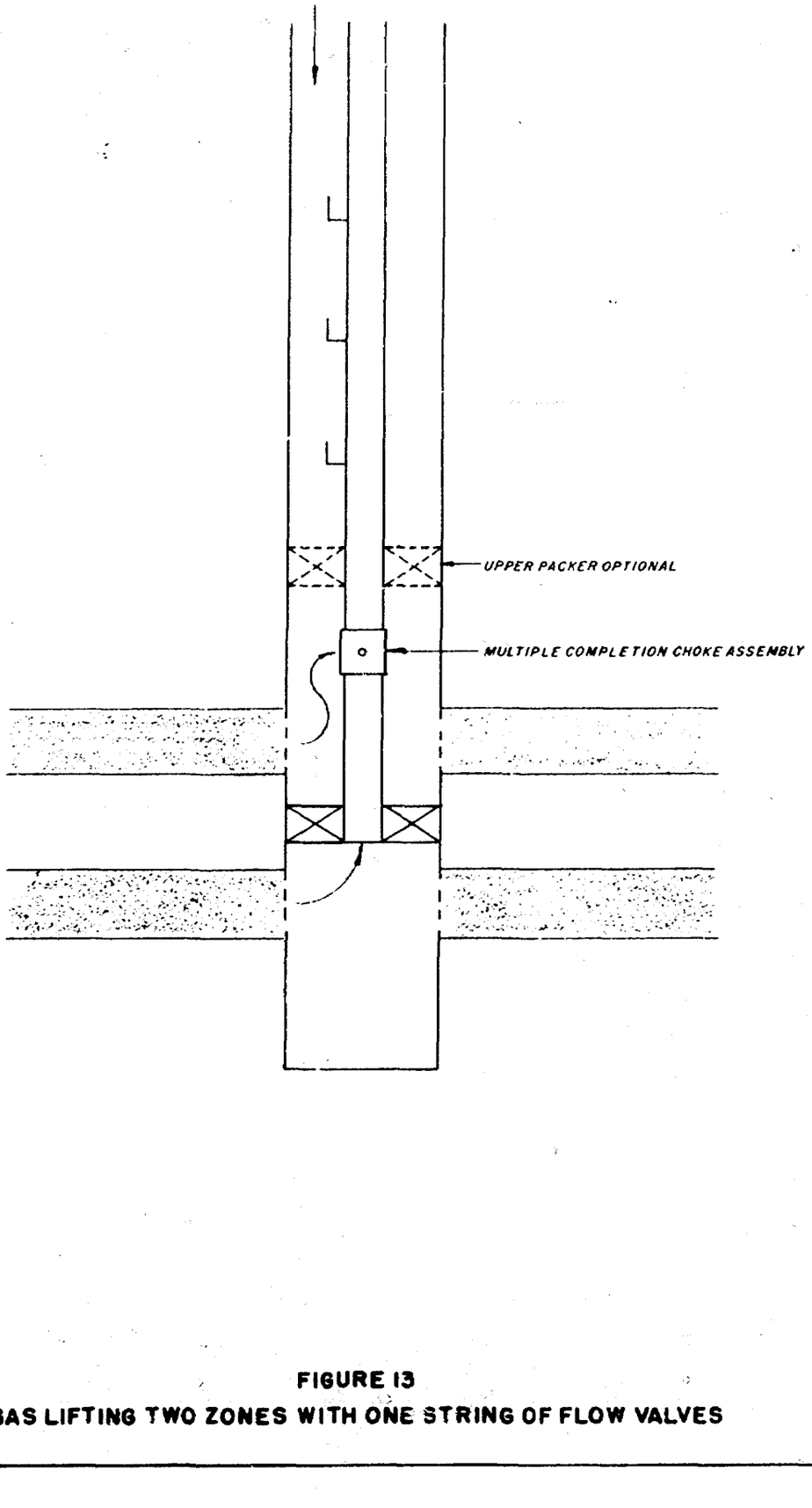


FIGURE 13

GAS LIFTING TWO ZONES WITH ONE STRING OF FLOW VALVES

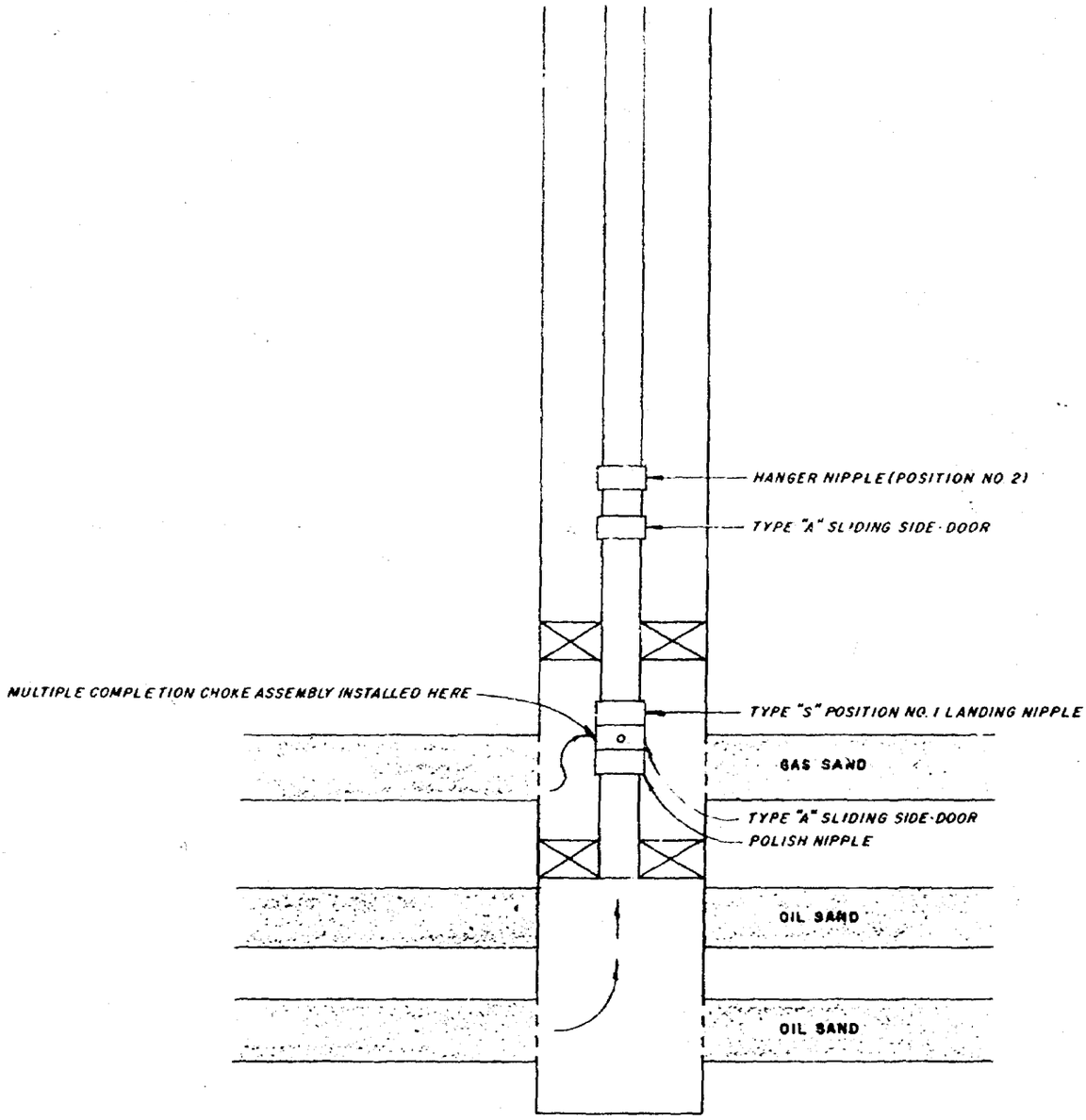


FIGURE 14

GAS LIFTING PERMANENT COMPLETION TYPE WELL

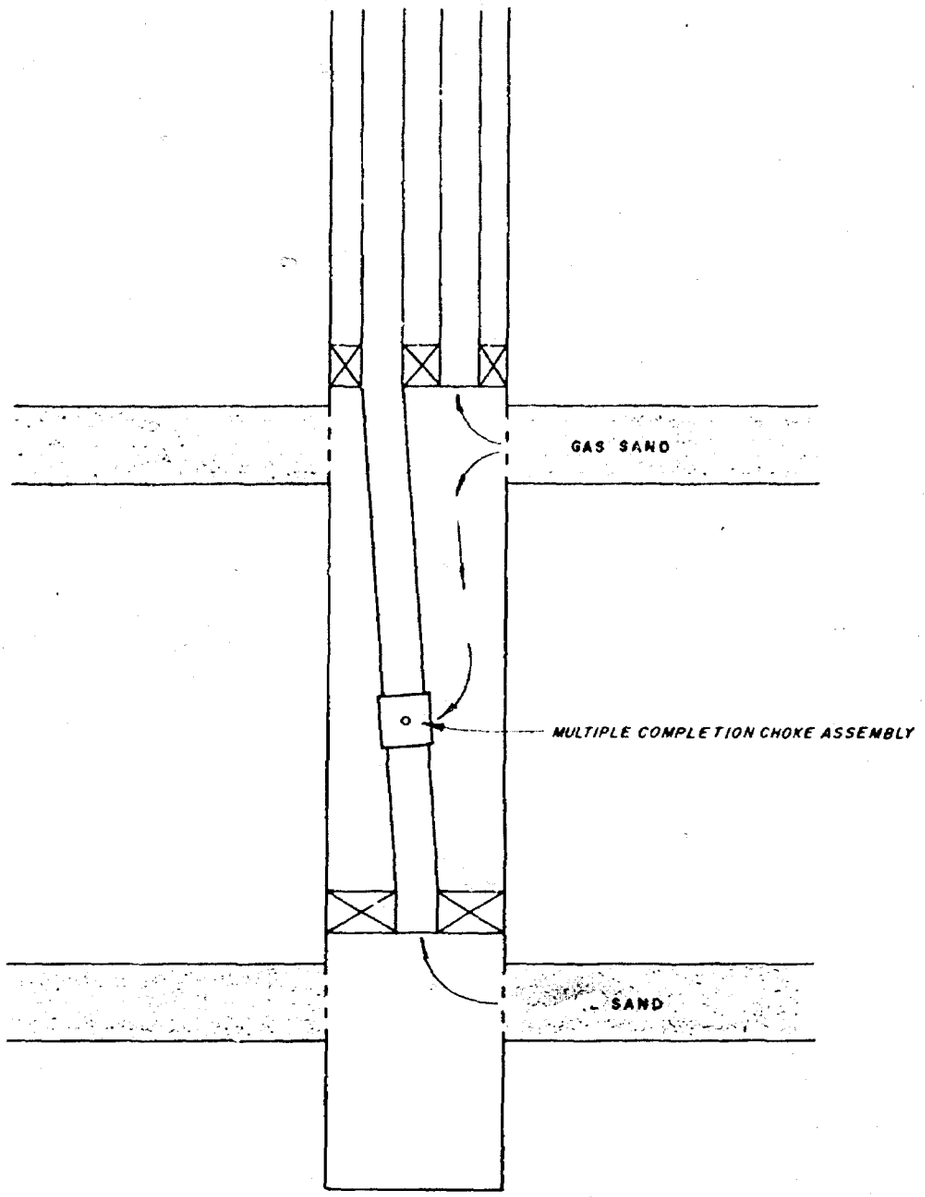


FIGURE 15

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.

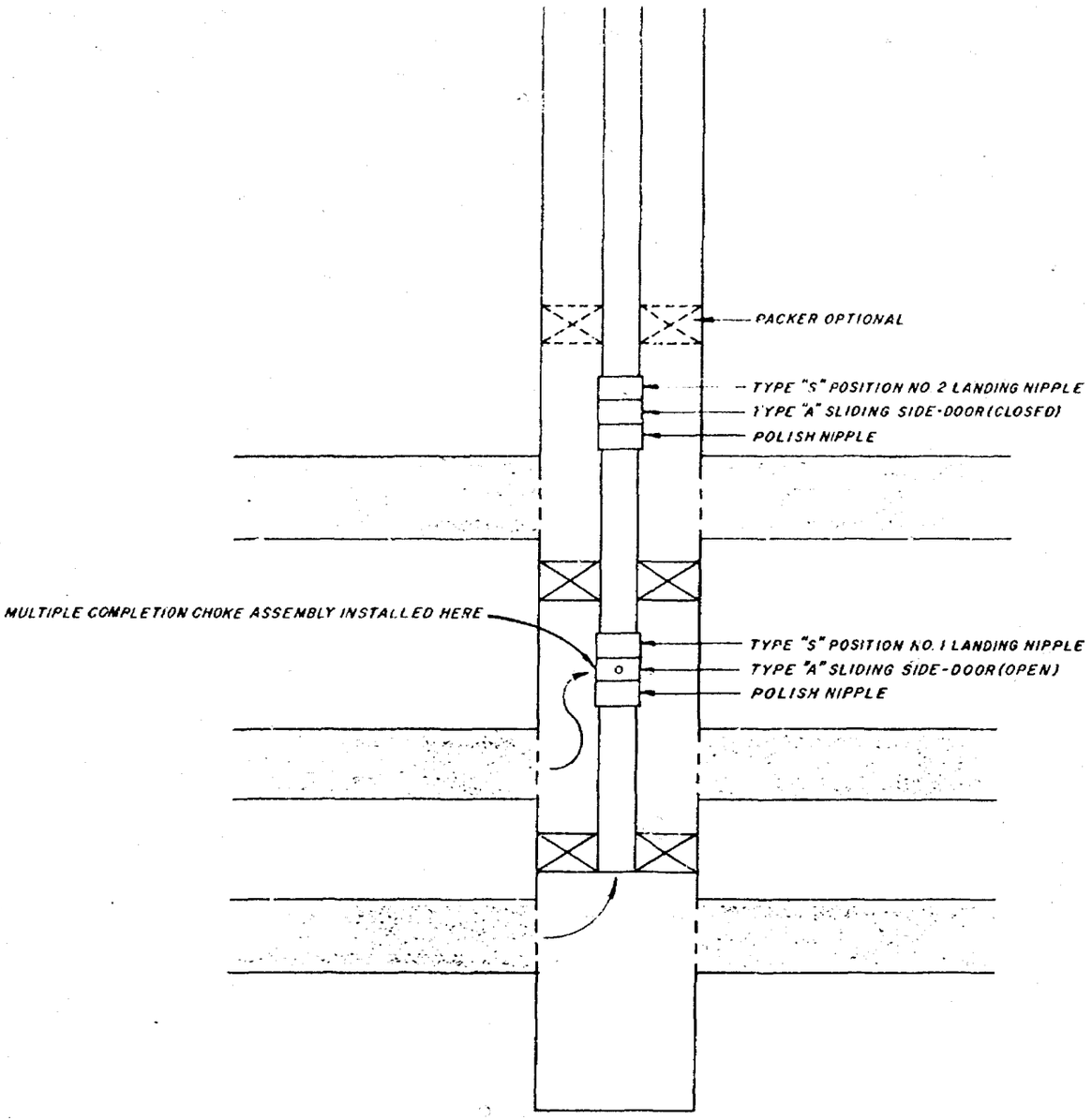


FIGURE 16
SELECTIVE COMPLETION USING MULTIPLE COMPLETION CHOKE ASSEMBLY. TWO OF THE ZONES ARE PRODUCED SIMULTANEOUSLY. WHEN EITHER IS DEPLETED, IT IS REPLACED WITH THE THIRD ZONE.

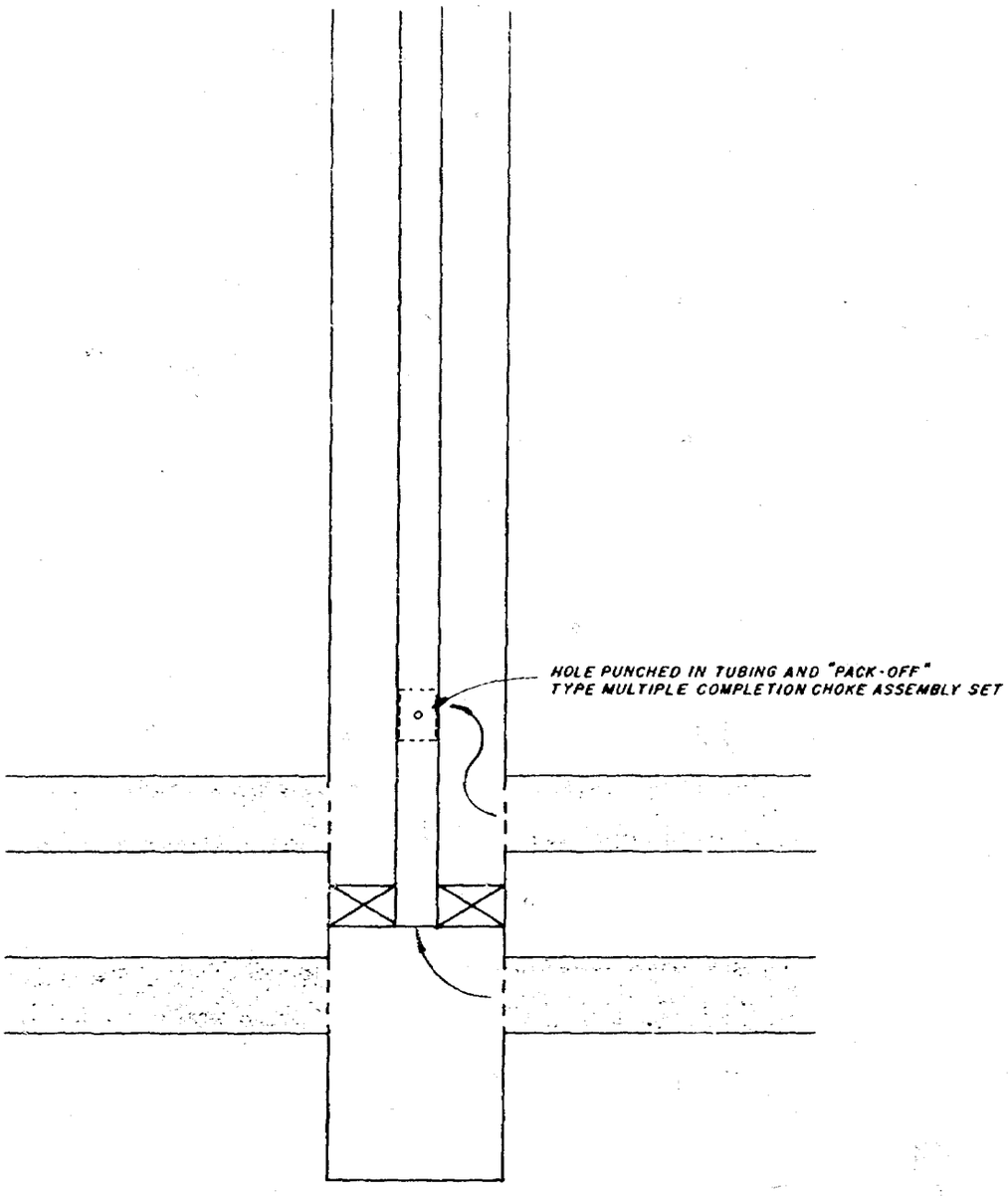


FIGURE 17
METHOD OF INSTALLING MULTIPLE COMPLETION CHOKE ASSEMBLY IN WELL NOT ORIGINALLY EQUIPPED WITH SIDE-DOOR CHOKE LANDING NIPPLE.

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OCTOBER 1961

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

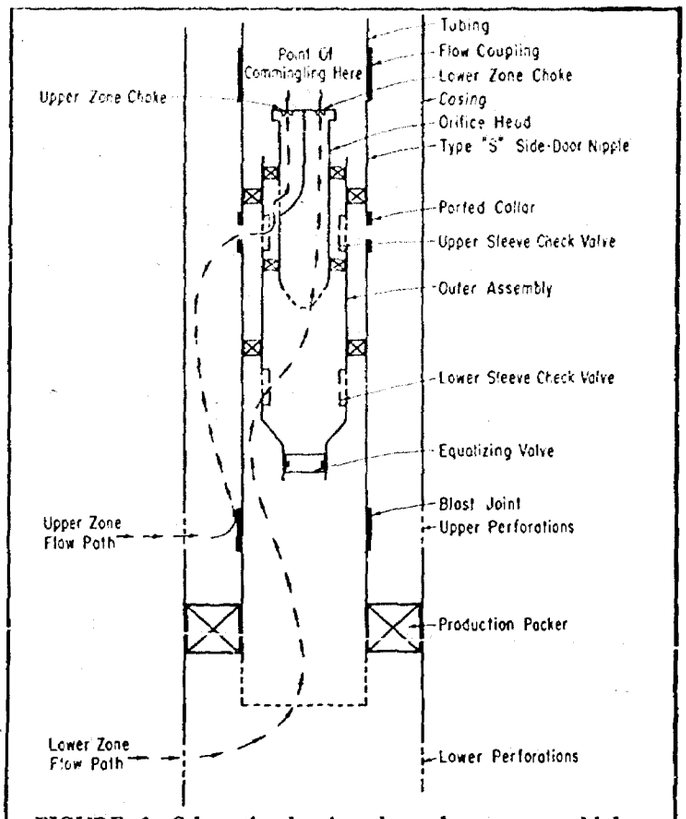


FIGURE 1—Schematic drawing shows how new multiple completion wireline tool works. Note that production is effectively separated until commingled above chokes.

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

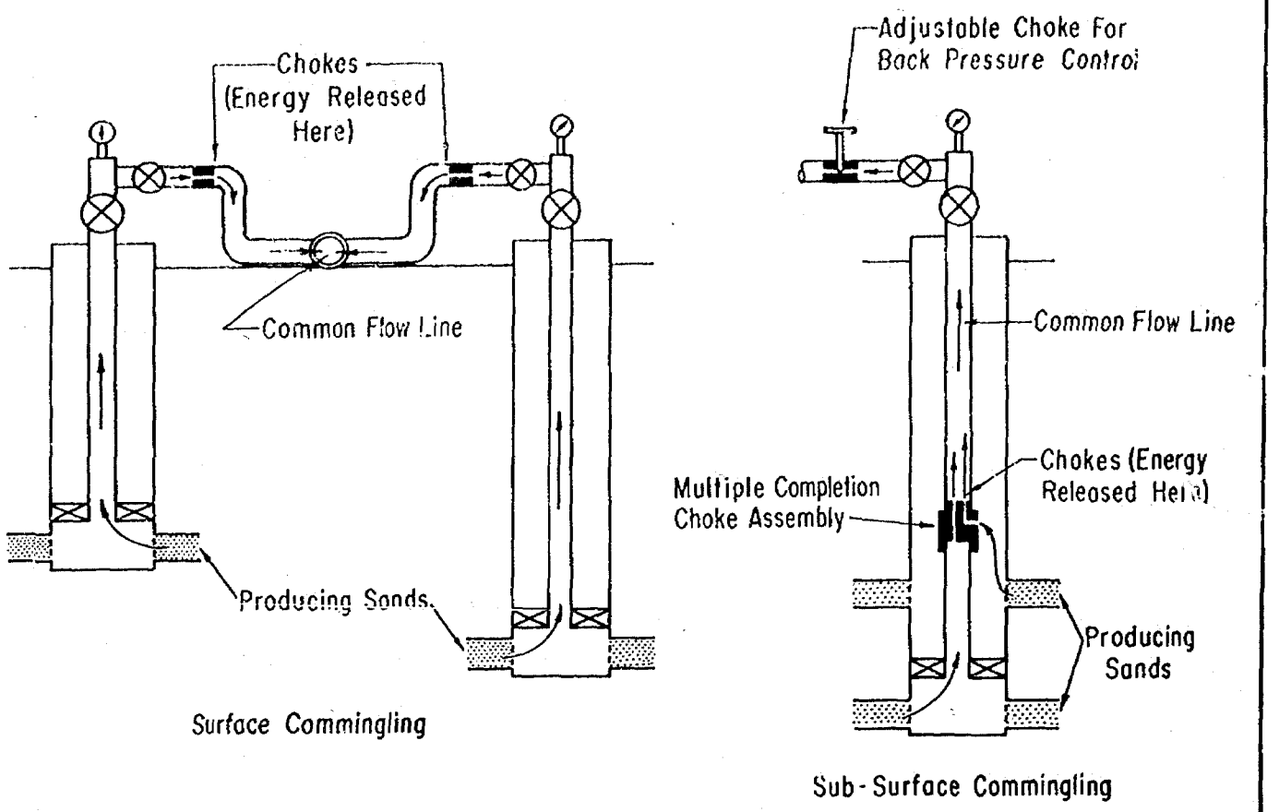


FIGURE 2—Downhole commingling is analoguous to surface commingling except that the pressure reduction is accomplished at the bottom of the hole where energy in released gas can be used.

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.

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.

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,

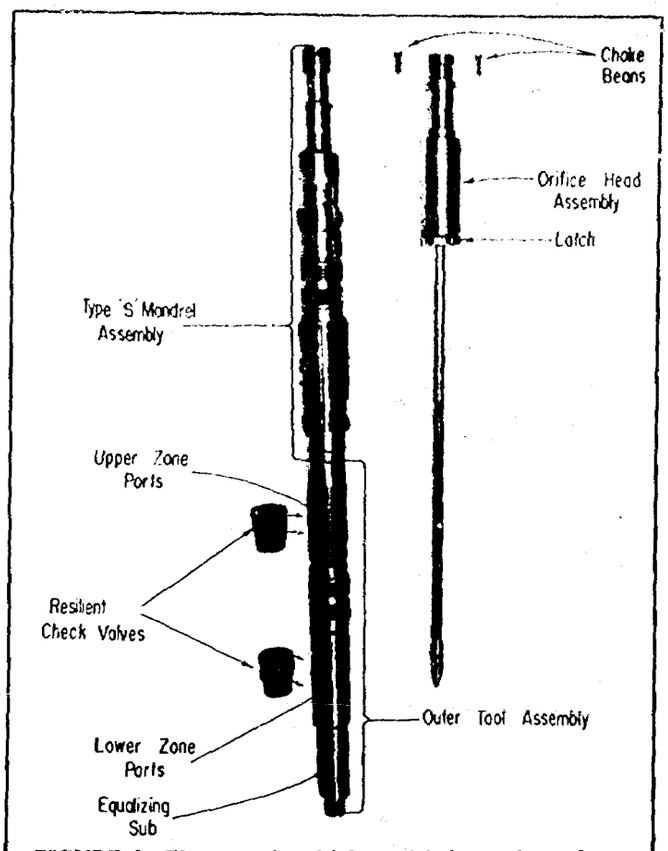


FIGURE 3—Elements of multiple completion tool are shown here. Orifice head assembly can be retrieved separately to blank off one choke for well test purposes or to change production chokes.

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	8-44"	6.38	175	27,500

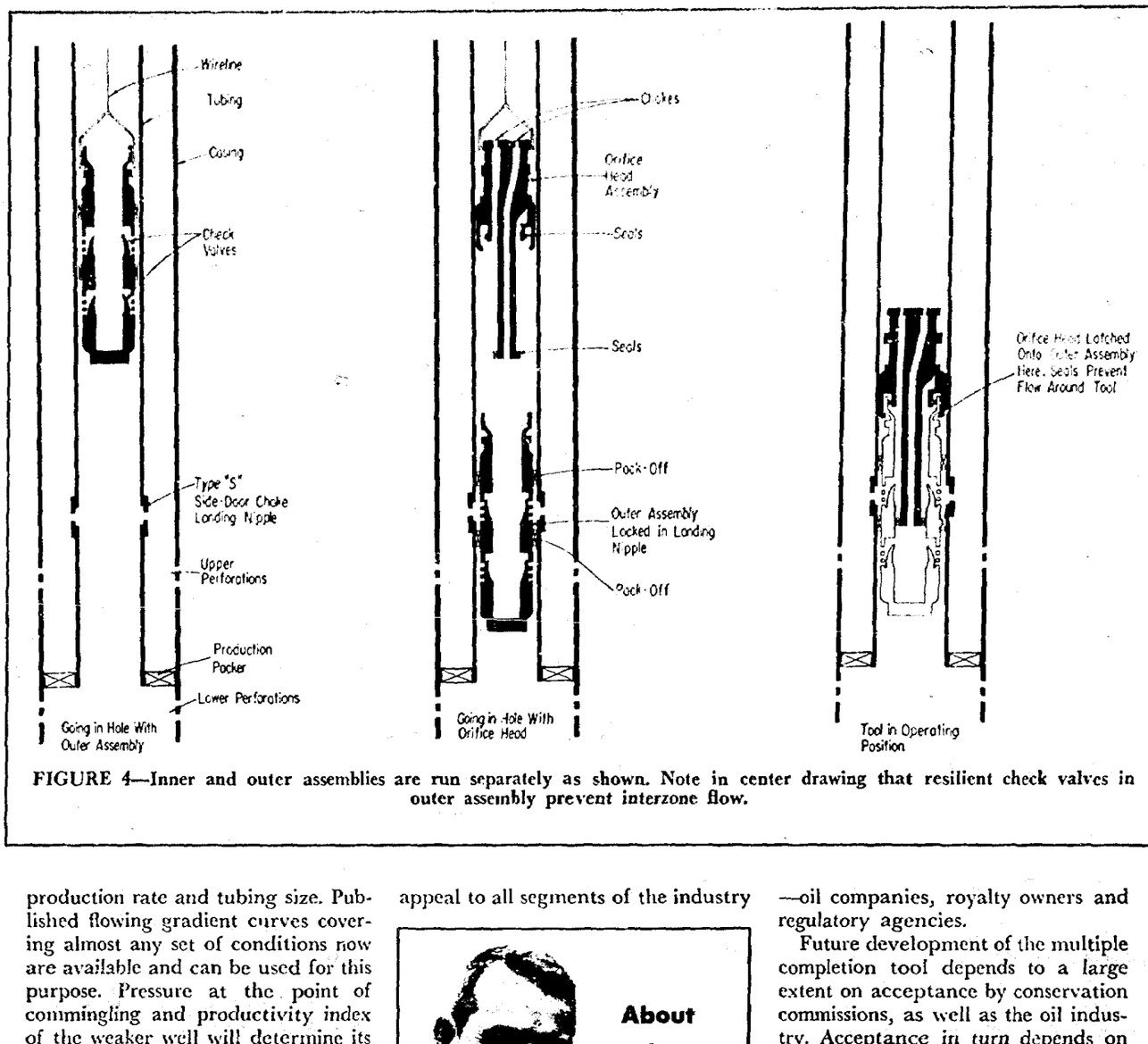


FIGURE 4—Inner and outer assemblies are run separately as shown. Note in center drawing that resilient check valves in outer assembly prevent interzone flow.

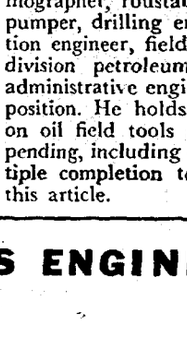
production rate and tubing size. Published flowing gradient curves covering almost any set of conditions now are available and can be used for this purpose. Pressure at the point of commingling and productivity index of the weaker well will determine its maximum rate of production.

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.

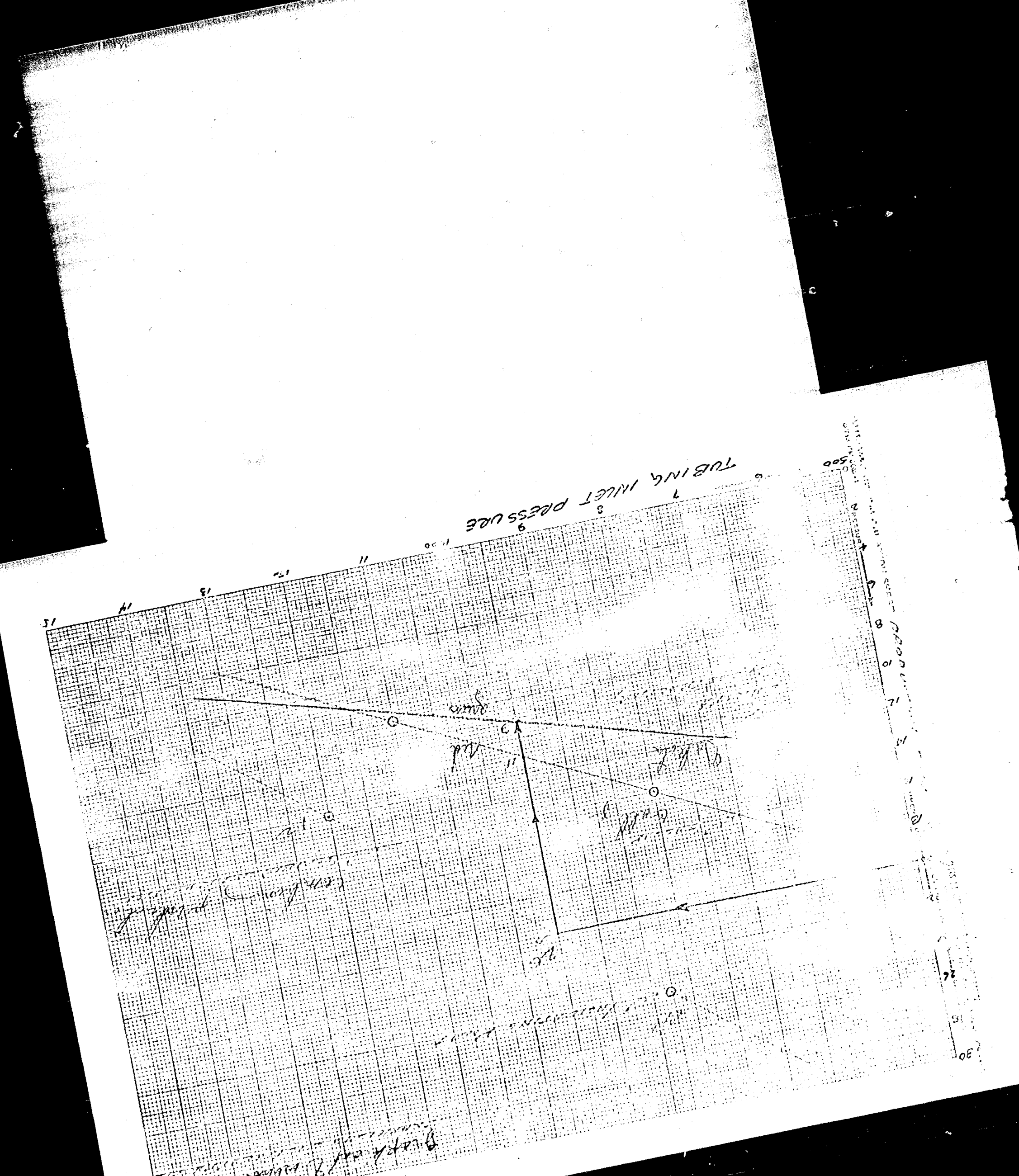


About the Author

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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OTIS ENGINEERING CORPORATION



DATA REQUIREMENTS FOR SURFACE COMMINGLING APPLICATIONS

Average Daily Oil Production for 90-Day Period:

Jicarilla 28 Well No. 1	Gallup	Dakota
May	13 BOPD	9 BOPD
June	13 BOPD	5 BOPD
July	10 BOPD	8 BOPD

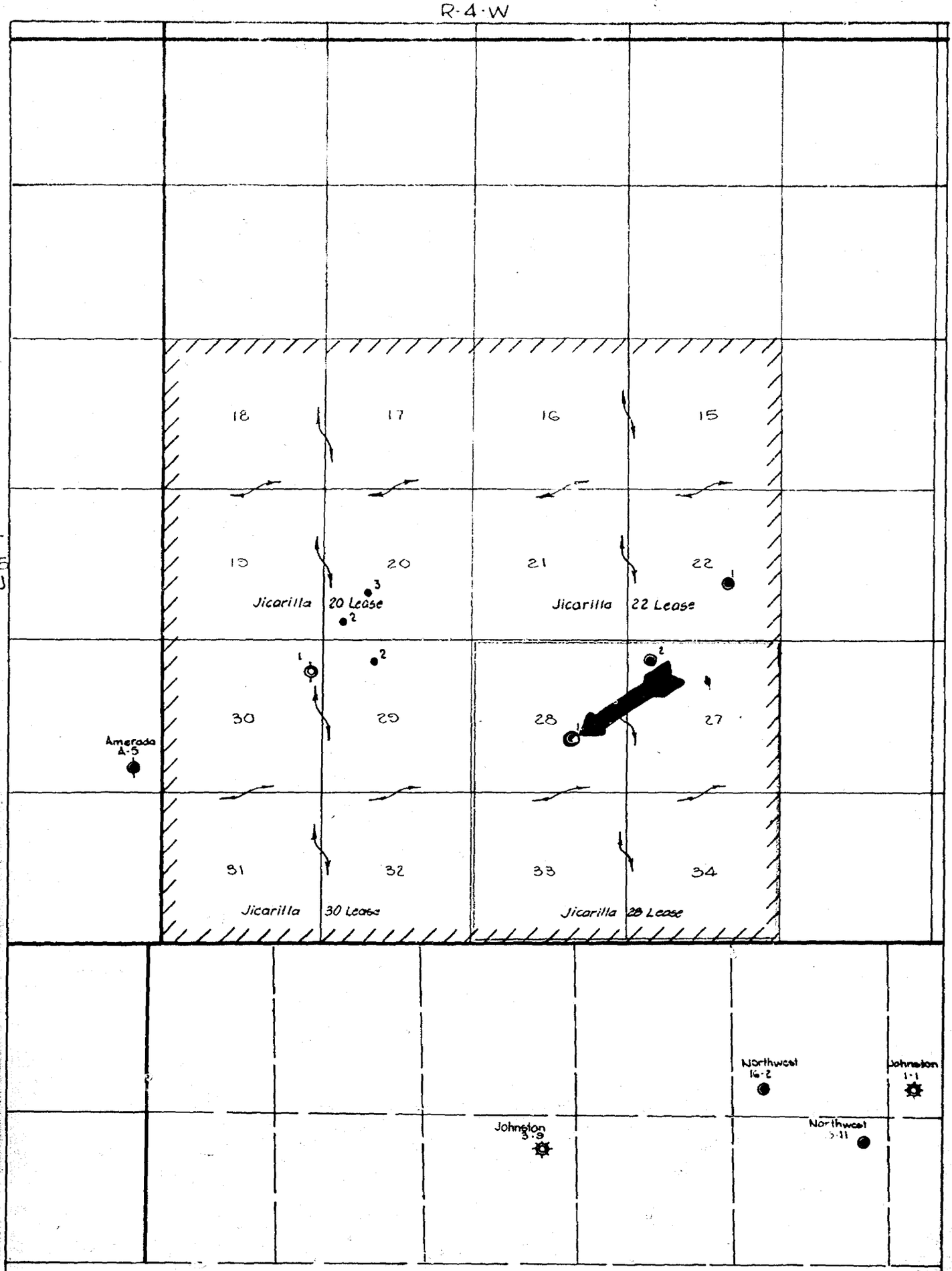
Top Unit Allowable: Gallup - 124 BOPD
Dakota - 164 BOPD
Crude Purchaser: Llaves Pipeline Ltd. - Farmington, New Mexico
Royalty Interest Owner: Jicarilla Apache Tribe
Liquid Hydrocarbon Gravities: Gallup - 44.4° API
Dakota - 48.4° API
Commingled Liquid Hydrocarbon Gravity - 46° API
Commingled gravity on adjacent lease (Jicarilla 22) over a six-month period has averaged 45.3° API.

Value of 44.4° API Crude = $2.35 per barrel
Value of 48.4° API Crude = $2.35 per barrel less $.08 = $2.27
Value of 46° API Crude = $2.35 per barrel less $.02 = $2.33

Anticipated Producing Rates: Gallup - 14 BOPD
Dakota - 8 BOPD

Value Calculations: Gallup 14 BOPD x $2.35 = $32.90
Dakota 8 BOPD x $2.27 = 18.16
Total Separate Value = $50.06/Day
Commingled Value - 22 BOPD x $2.33 = $51.26/Day

The value of the commingled production will not be less than the value of the production from each common source of supply.



LEGEND

- GALLUP OIL WELL
- DAKOTA - GALLUP DUAL COMPLETION

CONTINENTAL OIL COMPANY
PRODUCTION DEPARTMENT

DRAWN	SCALE 1" = 4000'	FILE NO.
CHECKED	DATE	
APPROVED	SHEET ____ OF ____	

WEST LINDRITH BLOCK
Rio Arriba Co., New Mexico

Case 3112

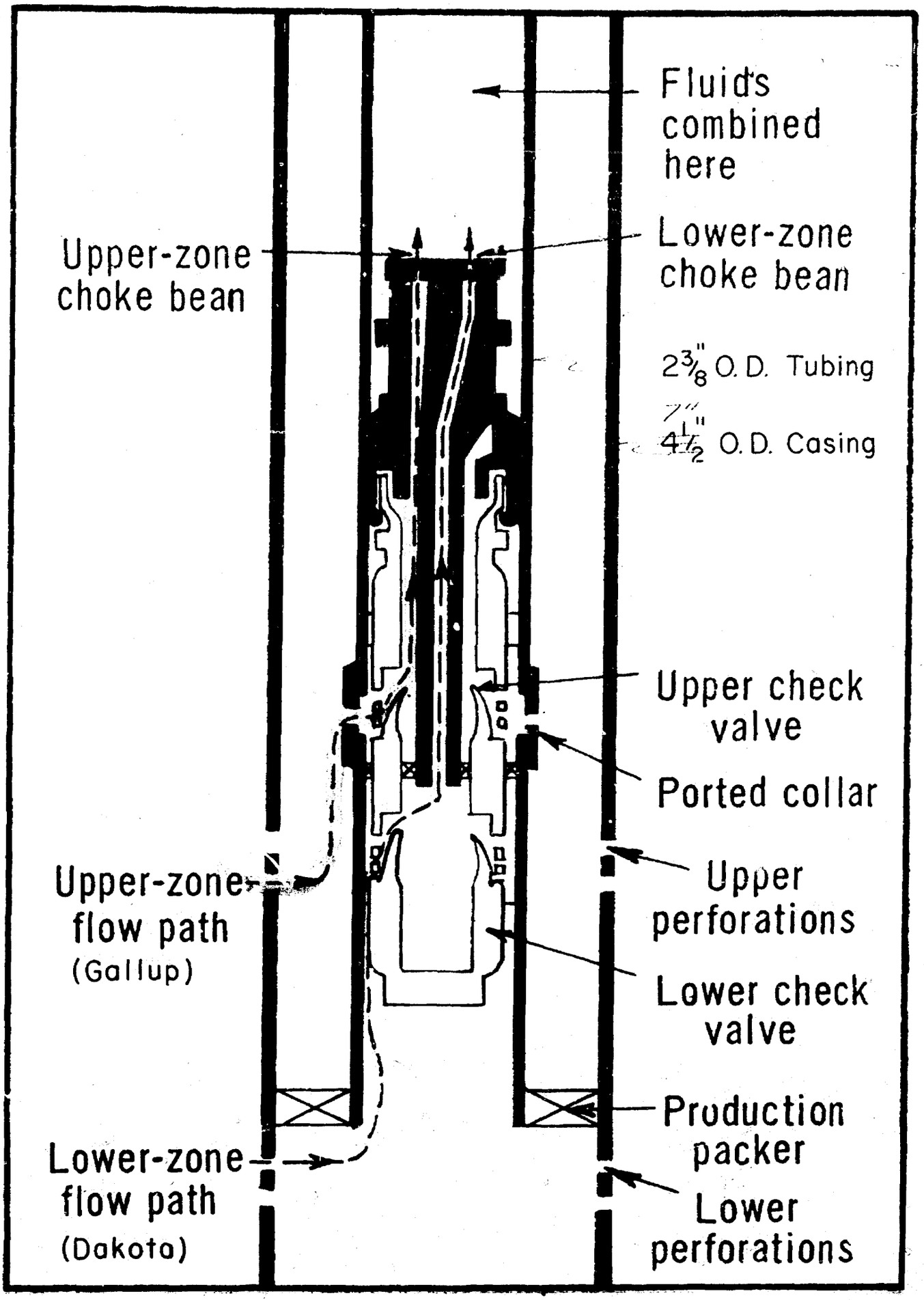


FIGURE NO. 7

Schematic diagram showing installation of Otis "Dual flow choke assembly" for dual zone downhole commingling.

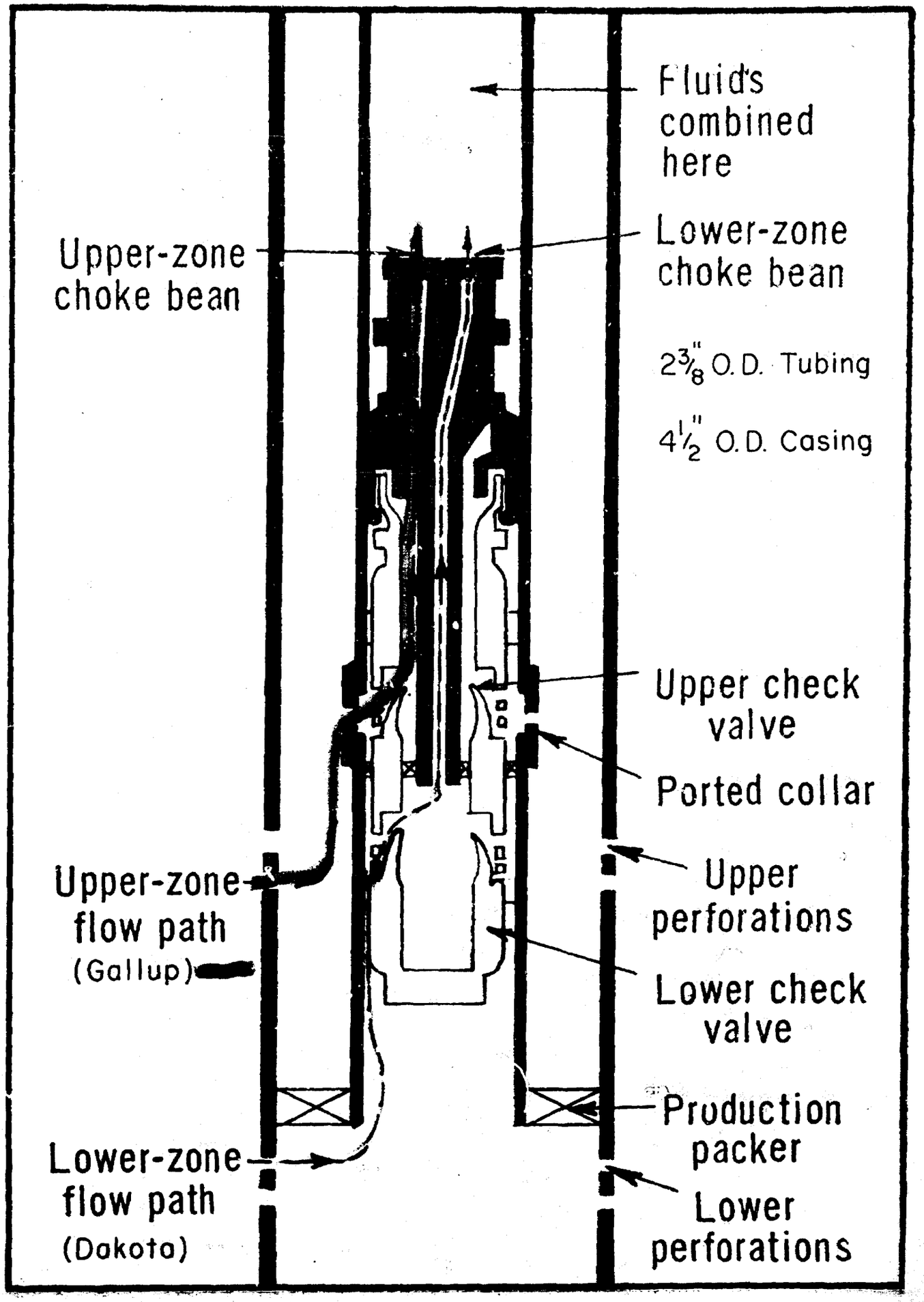


FIGURE NO. 7

Schematic diagram showing installation of Otis "Dual flow choke assembly" for dual zone downhole commingling.

PROPOSED ALLOCATION
ALLOCATION OF WELL NO. 1
(Based on subtraction method allocation form)

EXHIBIT NO. 5

OIL ALLOCATION

Dakota = $\frac{2.1 \text{ bbls.}}{25 \text{ bbls.}}$ X Gross Commingled Production

Gallup = Gross commingled production - Dakota allocated production

Example:
Total commingled production = 750 bbls.

Dakota allocation = $\frac{2.1}{25}$ X 750 bbls. = 278 bbls.

Gallup allocation = 750 bbls. - 278 bbls. = 472 bbls.

GAS PRODUCTION

Commingled GOR = 6599 : 1
Dakota GOR = 9216 : 1

Example

Theoretical Total Gas Production = 6599 (750 bbls.) = 4949 MCF
Theoretical Dakota Gas Prod. = 9216 (278 bbls.) = 2562 MCF
Theoretical Gallup Gas Production (Difference) = 2387 MCF

Actual Gas Sales = 4635 MCF
Lease Use = 450 MCF
Actual Total Gas = 5085 MCF

Dakota Gas Allocation = 5085 X $\frac{2562}{4949}$ = 2629 MCF

Gallup Gas Allocation (Difference) = 5085 - 2629 = 2456 MCF

Dakota GOR = $\frac{2629}{278}$ MCF = 9457

Gallup GOR = $\frac{2456}{472}$ MCF = 5203

BEFORE EXAMINER NUTTER
OIL CONSERVATION COMMISSION
EXHIBIT NO. 5
CASE NO. 2112

#5

JICARILLA 28 WELL NO. 1
COMBINED PRODUCTION PERFORMANCE - 1963-1964
GALLUP (PUMP) - DAKOTA (PLUNGER LIFT)

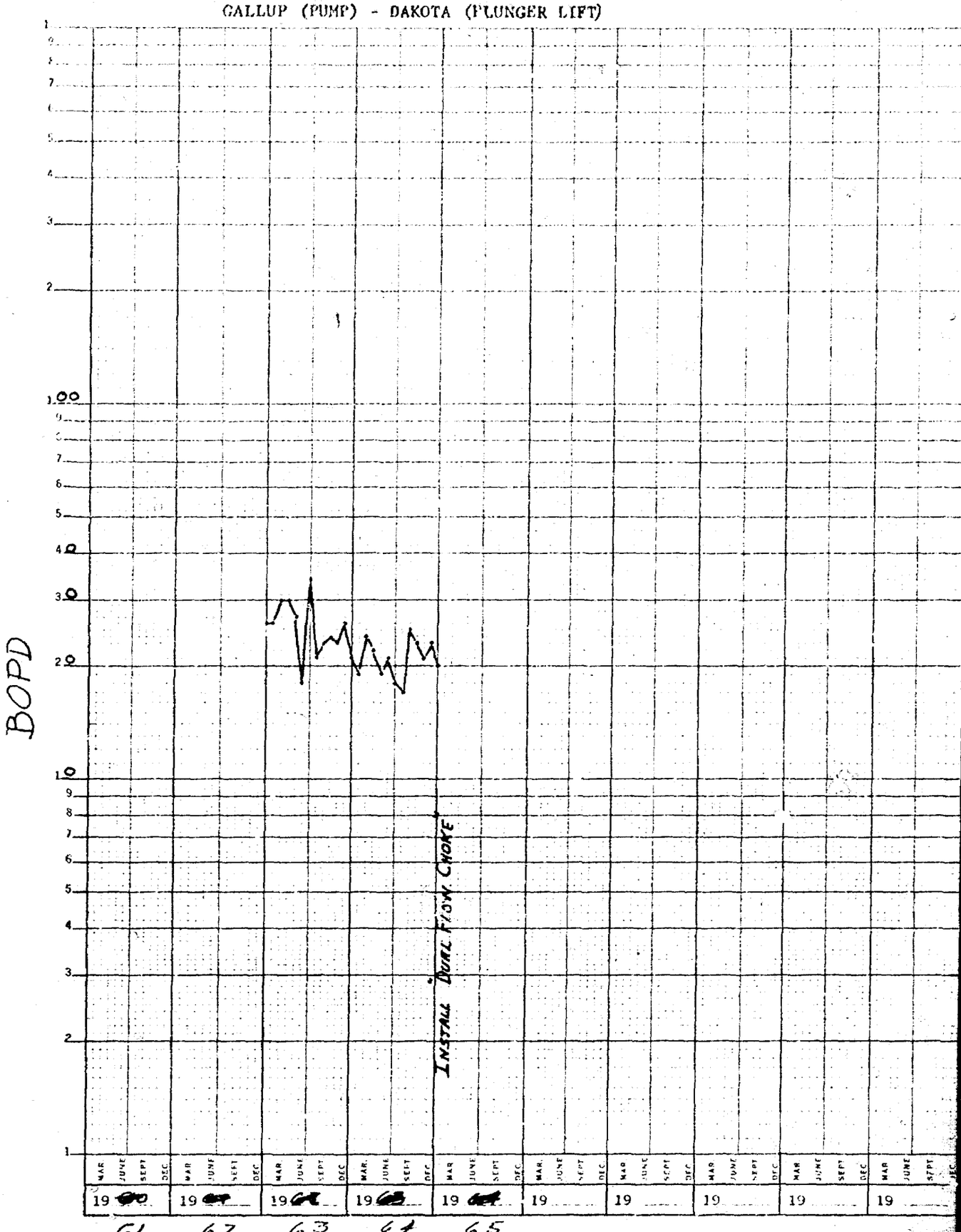


EXHIBIT No. 6

47 6843
20 YEARS BY MONTHS
X 3 LOG CYCLES
KEUFFEL & ESSER CO.

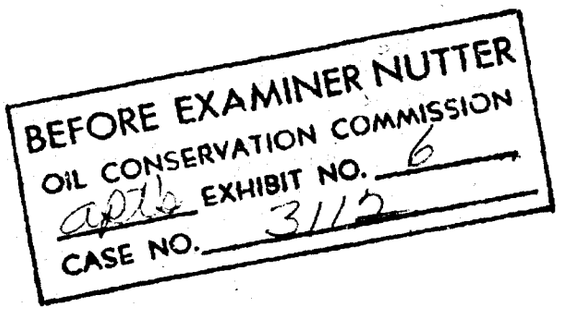

BEFORE EXAMINER NUTTER
OIL CONSERVATION COMMISSION
EXHIBIT NO. 6
CASE NO. 3112

EXHIBIT NO. 7

Conventional Well		Unitized Well	
7800' - 7" Casing	$ 55,200	7800' - 4 1/2" Casing	$11,700
13500' - 2 3/8" Tubing (New)	10,100	7800' - 2 3/8" Tubing	5,100
Casing-Tubing head, valves	4,500	Csg.-Tubing head, valves, etc.	2,500
Conventional pumping unit w/gas engine (6)	7,500	Miscellaneous equipment and "Cost Plus Choke"	2,500
6500' rods (6)	4,300		-
Bottom hole pump (6)	600		-
Intangible Drilling Costs	65,900	Intangible Drilling Costs	63,400
Contract Labor	4,000	Contract Labor	2,000
Production Equipment	8,000	Production Equipment	4,000
Surface Commingling Equip.	2,000		-
Sales Taxes	1,800	Sales Taxes	800
Miscellaneous	1,000	Miscellaneous	500
	$130,100		$93,100

Difference - $43,000

BEFORE EXAMINER NUTTER
OIL CONSERVATION COMMISSION
Apache EXHIBIT NO. 7
CASE NO. 3112

OIL CONSERVATION COMMISSION
P. O. BOX 871
SANTA FE, NEW MEXICO

LEGAL DIVISION
PHONE 827-2741

COPY

November 10, 1964

VIA AIR MAIL

Mr. George E. Blake
Division Manager
Otis Engineering Corporation
3813 West County Road
Odessa, Texas

Re: Case 3112

Dear Mr. Blake:

We are today forwarding, via air mail freight, collect, the demonstration model downhole commingling tool that you left to be examined by the Commission's engineers concerning the above case. An order should be issued in this case in the near future.

We appreciate the opportunity to examine the model.

Very truly yours,

J. M. DURRETT, Jr.
Attorney

JMD/esr

Orig. Exhibit No. 3

DATA SUBMITTED FOR COMMINGLING APPLICATION

Average Daily Oil Production for 30-Day Period:

Jicarilla 28 Well No. 1	Gallup	Dakota
May	15 BOPD	7 BOPD
June	13 BOPD	5 BOPD
July	16 BOPD	8 BOPD

Top Unit Allowable: Gallup - 126 BOPD
Dakota - 166 BOPD
Crude Purchaser: Navajo Pipeline Co. - Farmington, New Mexico
Royalty Interest Owner: Jicarilla Apache Tribe
Liquid Hydrocarbon Gravities: Gallup - 44.4° API
Dakota - 48.4° API
Commingled Liquid Hydrocarbon Gravity - 46° API
Commingled gravity on adjacent lease (Jicarilla 22) over a six-month period has averaged 45.3° API.

Value of 44.4° API Crude = $2.35 per barrel
Value of 48.4° API Crude = $2.35 per barrel less $.08 = $2.27
Value of 46° API Crude = $2.35 per barrel less $.02 = $2.33

Anticipated Producing Rates: Gallup - 14 BOPD
Dakota - 8 BOPD

Value Calculations: Gallup 14 BOPD x $2.35 = $32.90
Dakota 8 BOPD x $2.27 = 18.16
Total Separate Value = $50.06/Day
Commingled Value - 22 BOPD x $2.33 = $51.26/Day

The value of the commingled production will not be less than the value of the production from each common source of supply.

R-4-W

T 25 N

18 17 16 15

19 20 21 22

Jicarilla 20 Lease

Jicarilla 22 Lease

30 29 28 27

Amerada A-5

31 32 33 34

Jicarilla 30 Lease

Jicarilla 28 Lease

Northwest 16-2

Johnston 1-1

Johnston 3-5

Northwest 15-11

BEFORE EXAMINER UTZ
OIL CONSERVATION COMMISSION
Appl. EXHIBIT NO. 1
CASE NO. 3112

LEGEND

- GALLUP OIL WELL
- DAKOTA - GALLUP DUAL COMPLETION

CONTINENTAL OIL COMPANY
PRODUCTION DEPARTMENT

DRAWN	SCALE 1" = 4000'	FILE NO.
CHECKED	DATE	
APPROVED	SHEET OF	

WEST LINDRITH BLOCK
Rio Arriba Co., New Mexico

DATA REQUIREMENTS FOR SURFACE COMMINGLING APPLICATIONS

Average Daily Oil Production for 30-Day Period:

Jicarilla 28 Well No. 1	Gallup	Dakota
May	13 BOPD	5 BOPD
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Top Unit Allowable: Gallup - 124 BOPD
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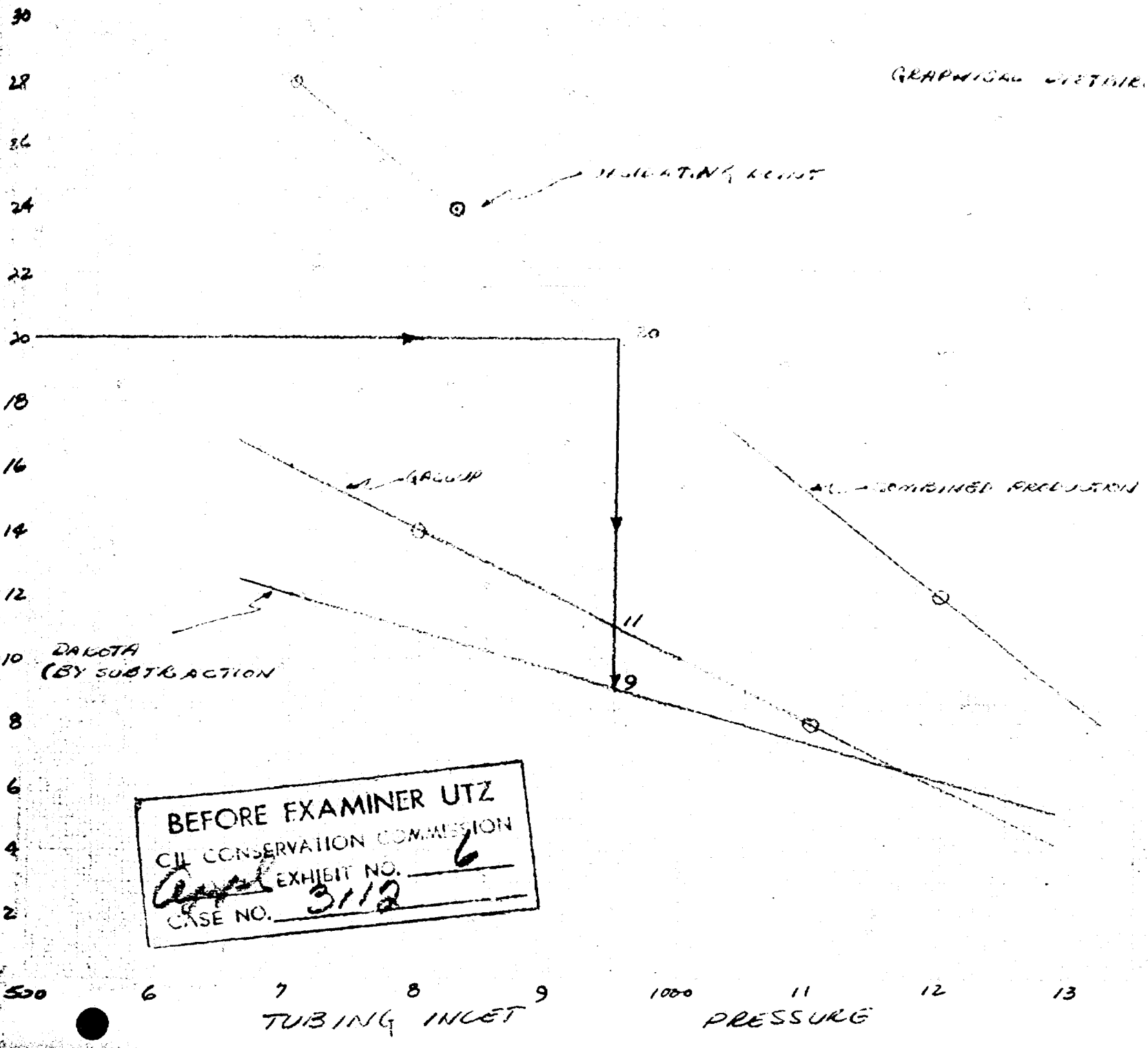
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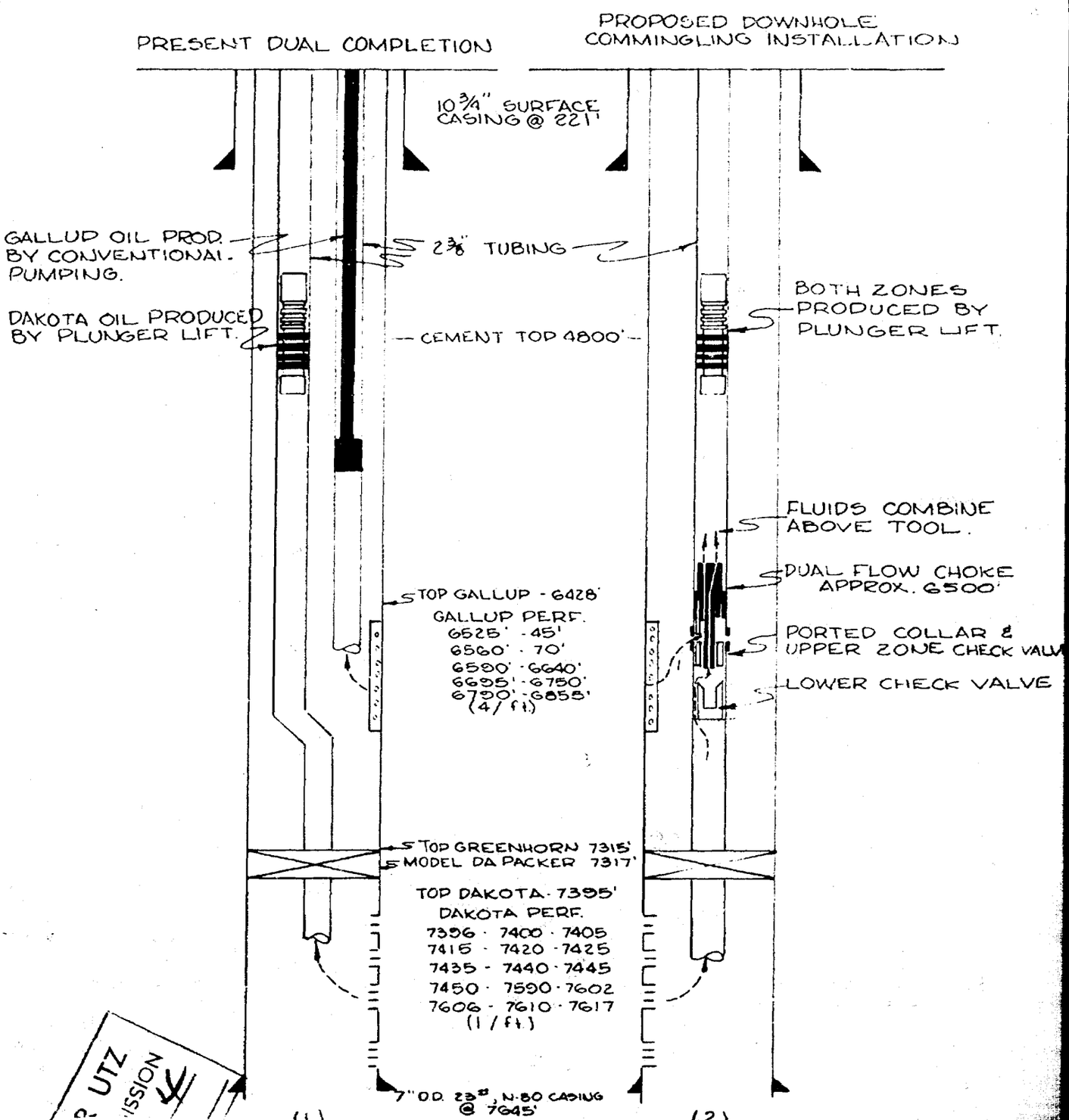
The value of the commingled production will not be less than the value of the production from each common source of supply.

BEFORE EXAMINER UTZ
OIL CONSERVATION COMMISSION
EXHIBIT NO. 3
CASE NO. 3112

GRAPHICAL DETERMINATION CURVE



BEFORE EXAMINER UTZ
OIL CONSERVATION COMMISSION
EXHIBIT NO. 6
CASE NO. 3112



JICARILLA 28 WELL No. 1

SCHEMATIC DIAGRAM SHOWING PRESENT CONVENTIONAL DUAL GALLUP DAKOTA COMPLETION(1) AND PROPOSED INSTALLATION OF "DUAL FLOW CHOKE ASSEMBLY" DUAL ZONE DOWNHOLE COMMINGLING(2).

BEFORE E... UTZ
OIL CONSE... SSION
CASE NO. 3112 EX. 4

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

P. O. Drawer 1857
Roswell, New Mexico 88201

RECEIVED
DURANGO PROD.
SEP 25 1964
OFFICE MGR.
DIST. ENG.

September 21, 1964

Continental Oil Company
P. O. Box 3312
Durango, Colorado

Attention: Mr. H. D. Haley

Gentlemen:

Your letter of August 11, with attachments, requests approval to commingle oil production from the Gallup and Dakota formations in your well No. 28-1 Jicarilla Apache on Jicarilla tribal Contract No. 66.

According to the system, as outlined in your proposal, communication between the reservoirs will be accomplished by the use of a downhole separation tool. By additional information submitted in a separate letter on September 8 you state the production from each reservoir will be allocated through the testing of each zone by manually blanking off one zone in the separation tool and producing the other zone. Form 9-361, Lessee's Monthly Report of Sales and Royalty, must show all computations used in the calculation of oil volume for each formation.

The method you propose for the downhole commingling is hereby approved. Any change in the system must be approved by this office.

Sincerely yours,

JOHN A. ANDERSON
Regional Oil & Gas Supervisor

BEFORE EXAMINER UTZ
OIL CONSERVATION COMMISSION
EXHIBIT NO. 8
CASE NO. 3112

SHELL OIL COMPANY

SHELL BUILDING
P O BOX 2099
HOUSTON, TEXAS 77001

August 25, 1964

Subject: Jicarilla Apache #3 Well No. 1
Sec. 26, T-25-N, R-4-W
Rio Arriba County, New Mexico

RECEIVED
AUG 27 1964
OIL CON. COM.
DIST. 3

Continental Oil Company
P. O. Box 3312
Durango, Colorado

Attention Mr. H. D. Haley

Gentlemen:

In response to your letters of August 14, 1964, and August 21, 1964, and based on the facts set out therein, this is to advise that Shell Oil Company, as purchaser of the crude oil production, does not object to commingling the Gallup and Dakota production from the subject well.

Please advise us of the effective date of such commingling.

Yours very truly,

B. G. Crocker
Crude Oil Representative

DKB:SMP

BEFORE EXAMINER UTZ
OIL CONSERVATION COMMISSION
EXHIBIT NO. 9
CASE NO. 3112

'65 AUG 2 AM 7 30

CONTINENTAL OIL COMPANY

P. O. Box 3312
Durango, Colorado 81302
July 29, 1965

New Mexico Oil Conservation Commission
P. O. Box 2088
Santa Fe, New Mexico

Attn: Mr. D. S. Nutter - Chief Examiner

Dear Mr. Nutter:

Attached is another copy of Exhibit No. 4 (Case #3112) which you requested be brought up to date.

Also attached are copies of the recorded pressures on Jicarilla 28 Well No. 1, which you requested, from May 4, 1965, to June 19, 1965. The charts show the surface pressure buildup on the Gallup (upper) zone during the Dakota allocation test and shut-in period for the packer leakage test taken near the end of the test period. A copy of the charts obtained during the packer leakage test are also included. A seven-day chart starting July 1, 1965, is also attached for your information which shows the casing and tubing pressures while producing both zones up the tubing through the dual flow choke. This chart was taken after the final packer leakage test.

If any additional information is required, please advise.

Very truly yours,

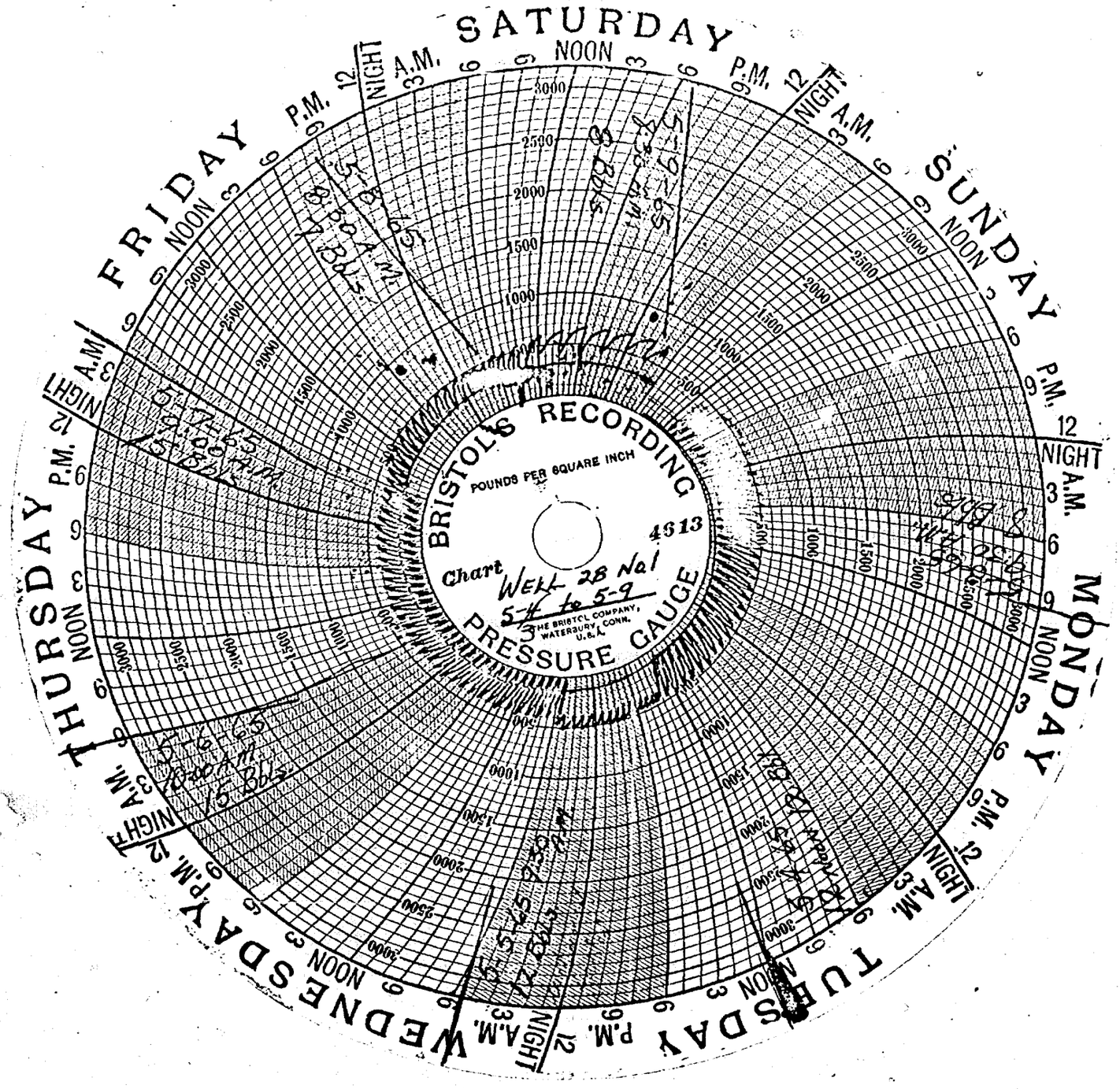
G. A. Brown

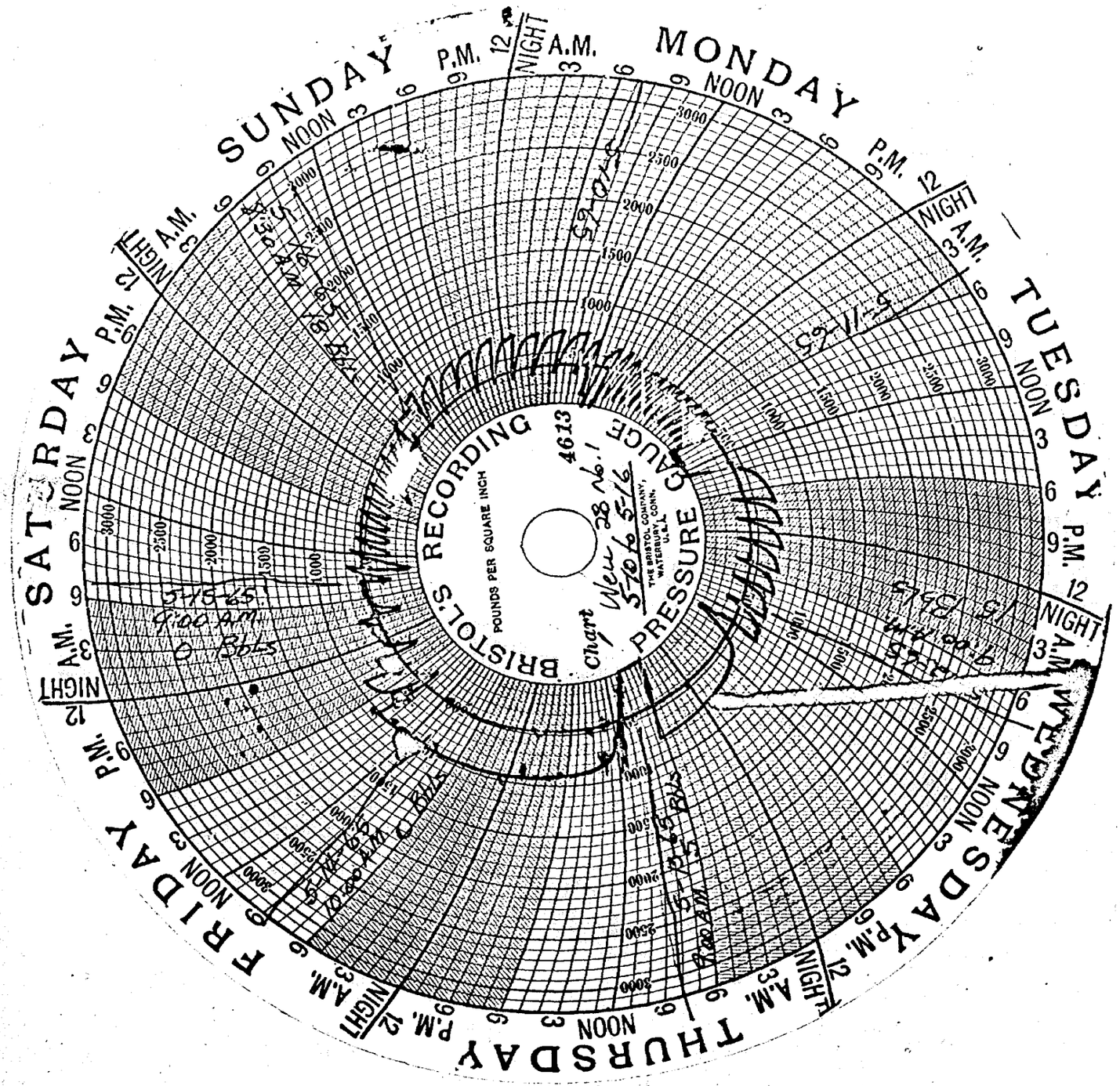
G. A. Brown
Production Engineer
Durango District
Production Department

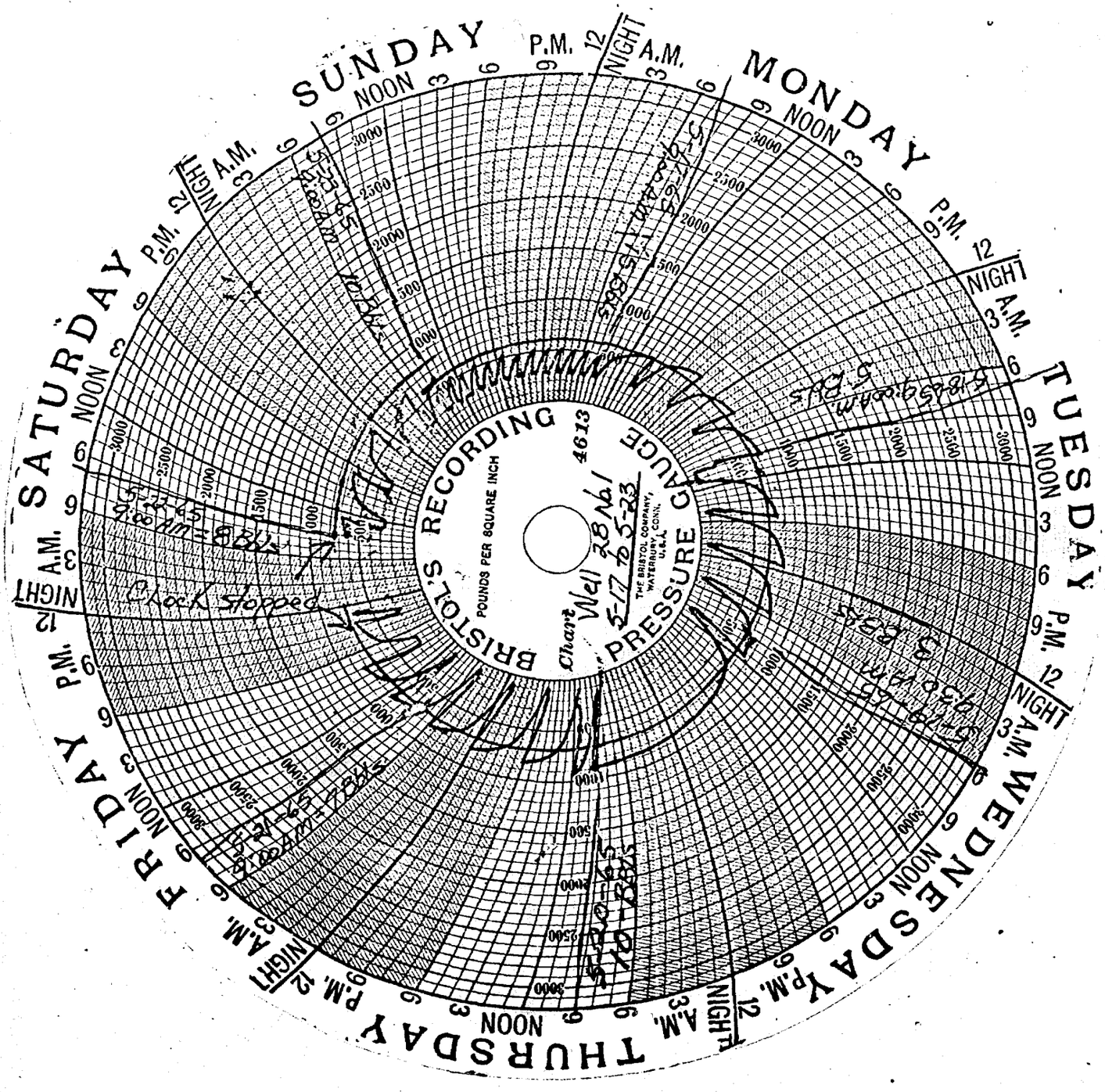
GAB/ae

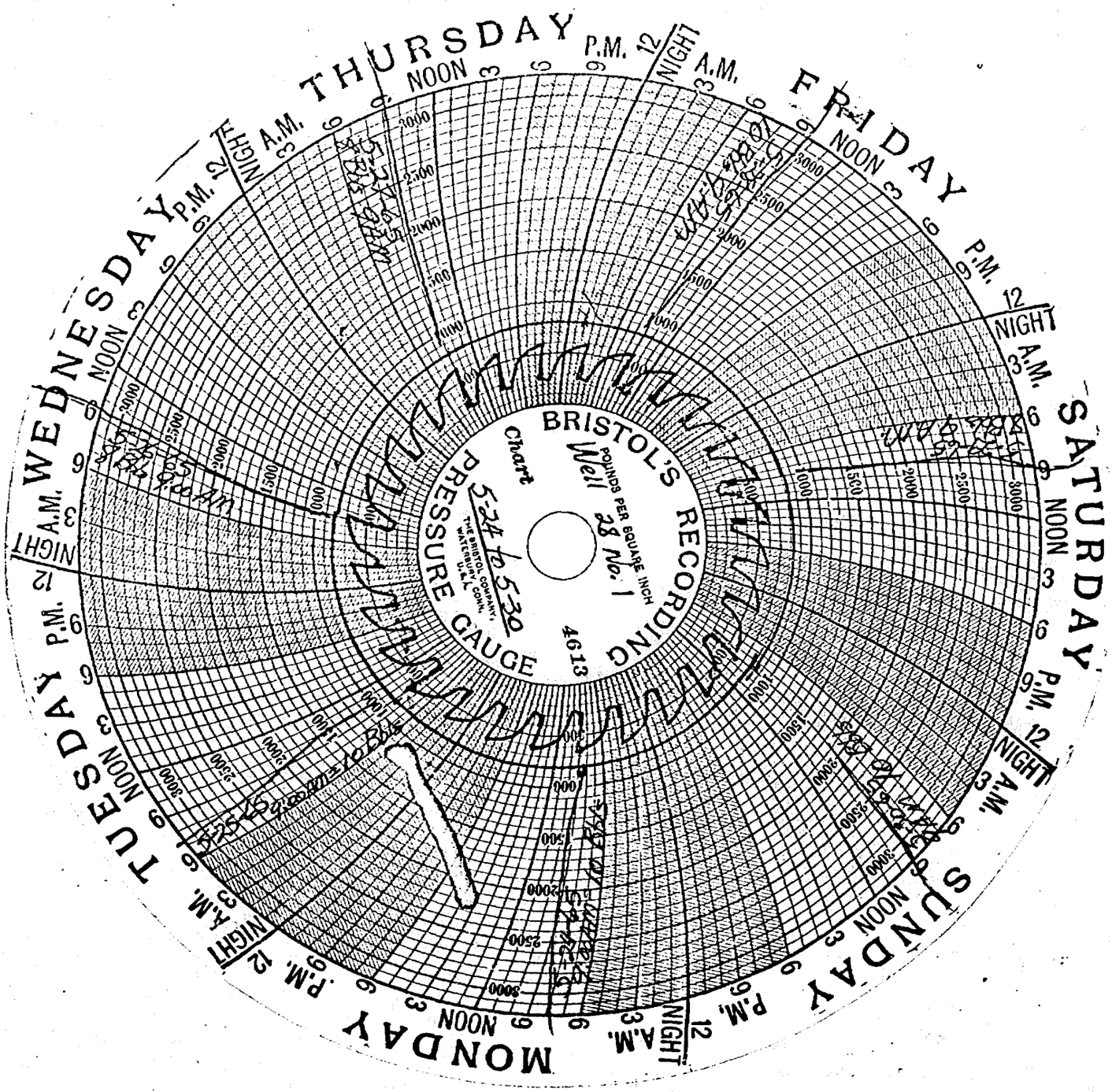
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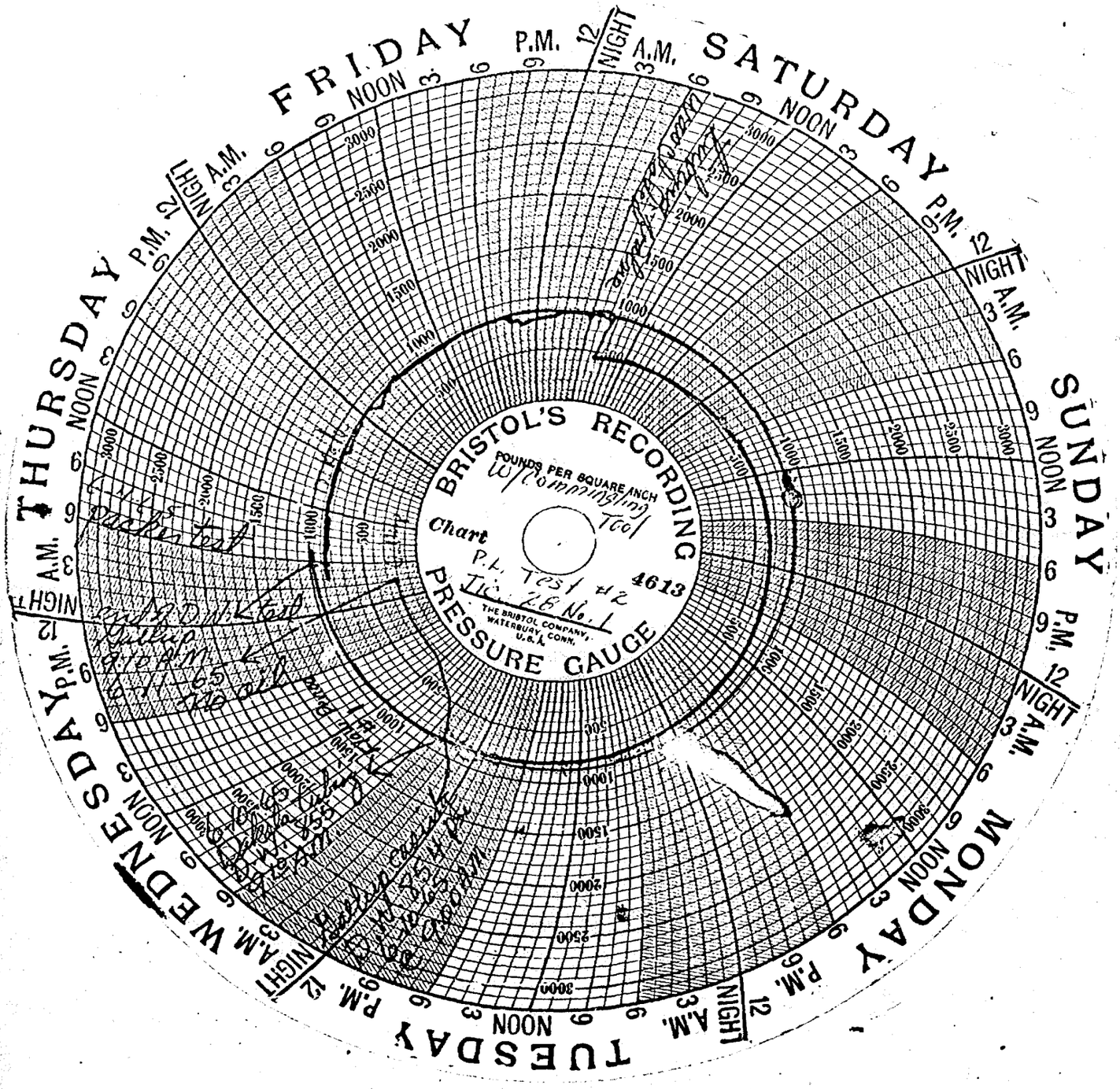
PIONEERING IN PETROLEUM PROGRESS SINCE 1875

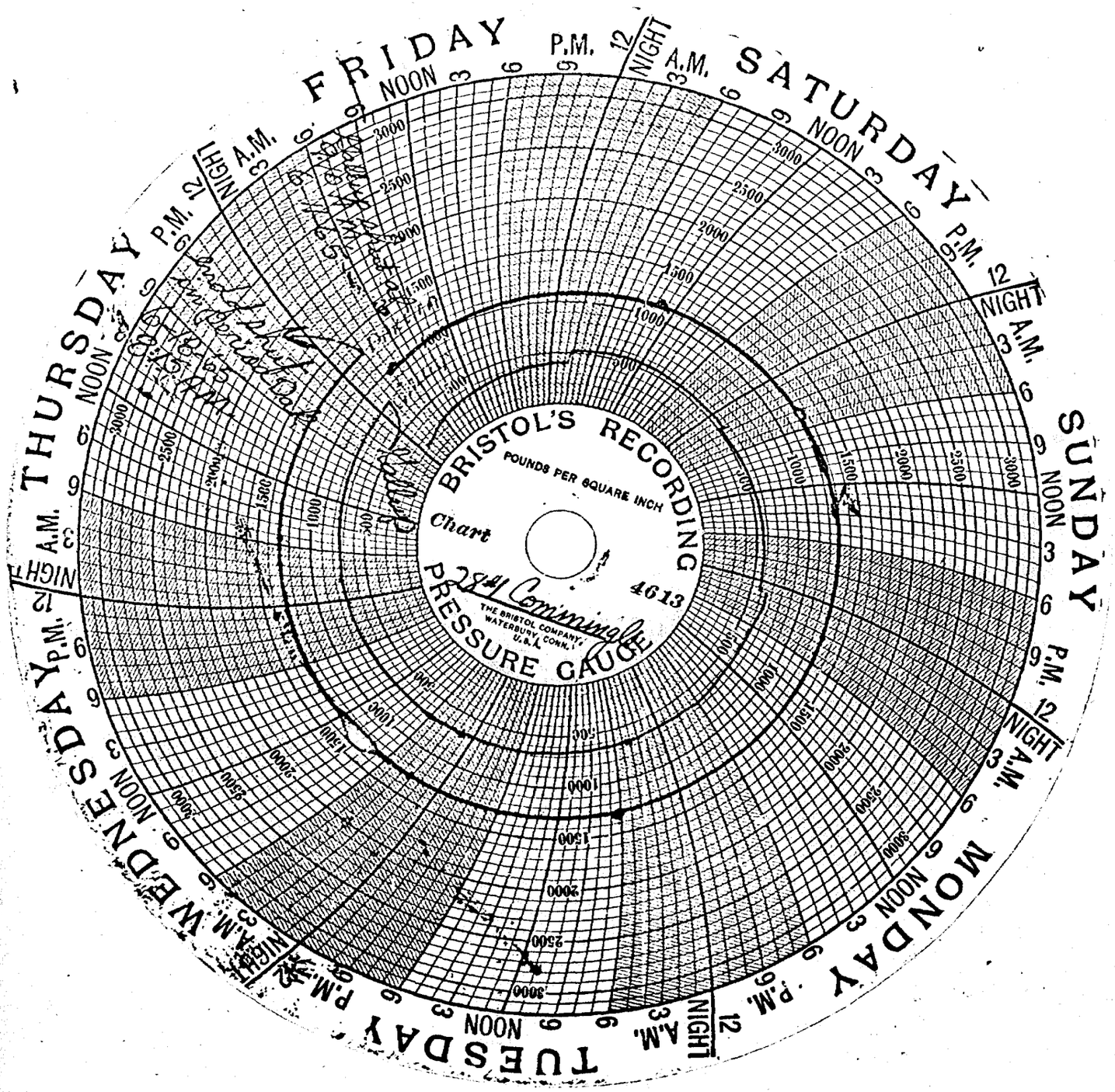

SATURDAY
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
NOON
NIGHT
A.M.
P.M.
BRISTOL'S RECORDING
POUNDS PER SQUARE INCH
PRESSURE GAUGE
THE BRISTOL COMPANY, WATERBURY, CONN. U.S.A.
4613
Chart
Well 28 Nal
5-4 to 5-9

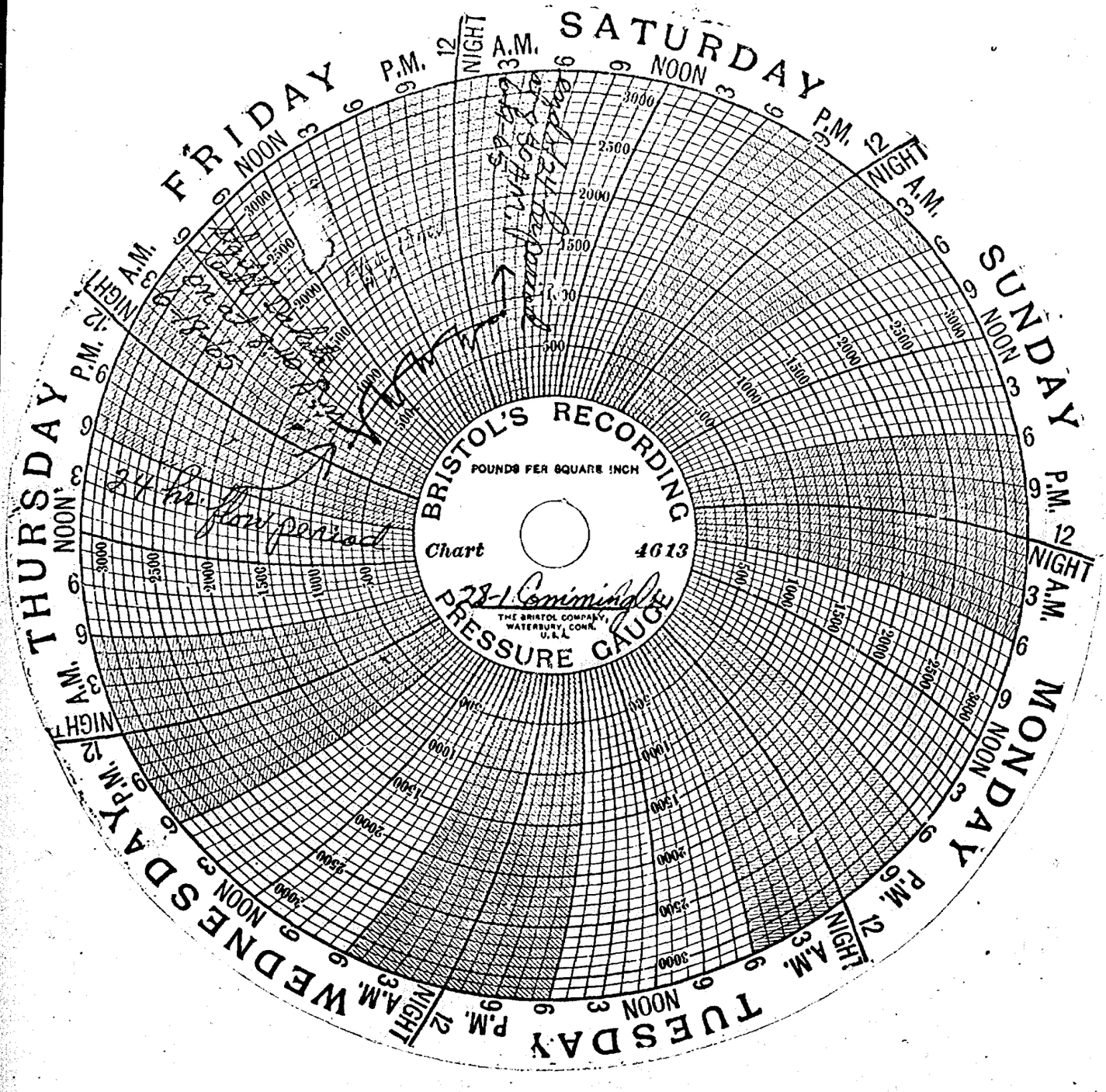

SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
A.M.
P.M.
NOON
NIGHT
BRISTOL'S RECORDING PRESSURE GAUGE
POUNDS PER SQUARE INCH
THE BRISTOL COMPANY, WATERBURY, CONN. U.S.A.
4613
Chart Wew 38 No. 1
570 to 576

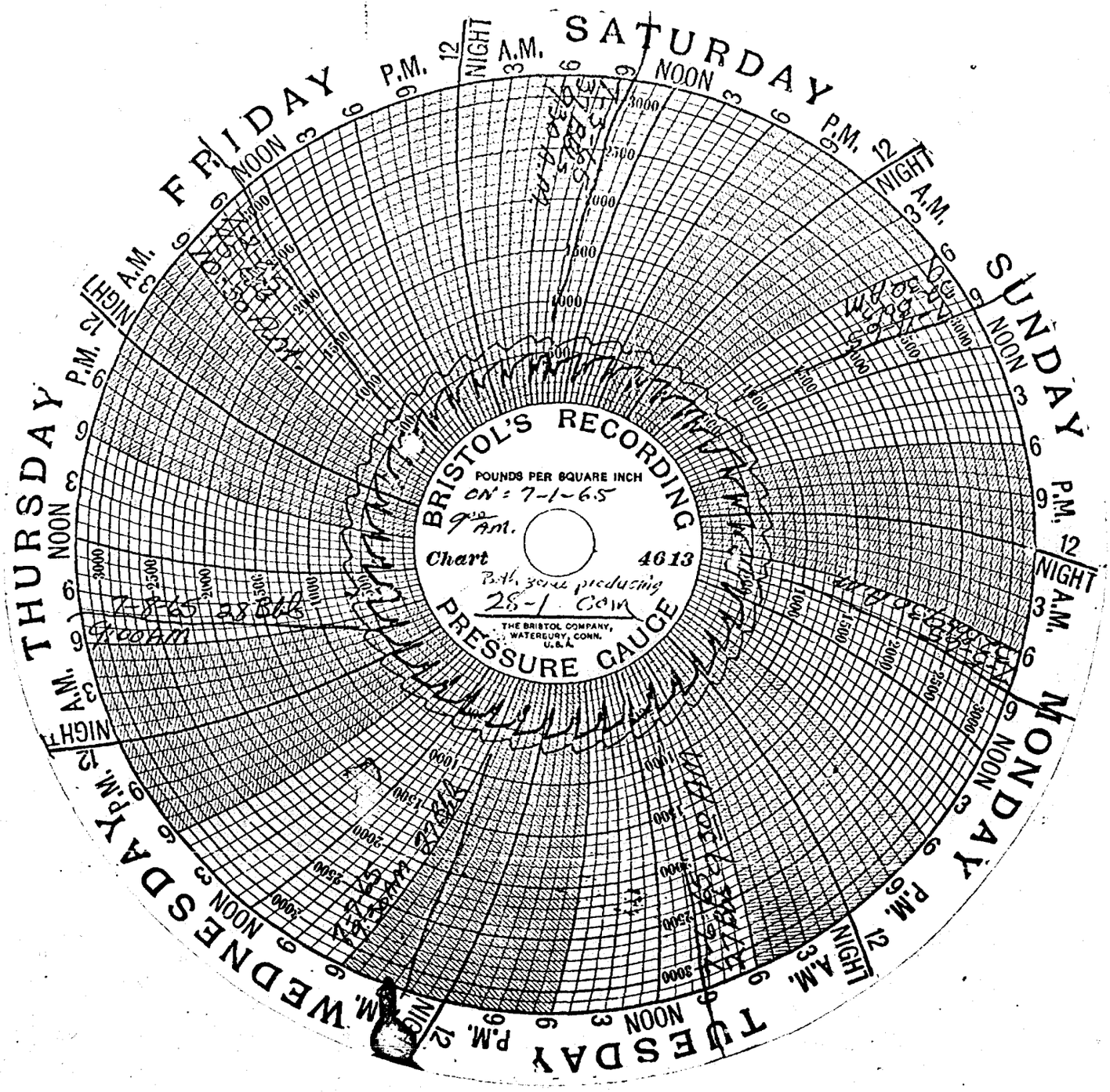

SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
NOON
NIGHT
A.M.
P.M.
BRISTOL'S RECORDING PRESSURE GAUGE
POUNDS PER SQUARE INCH
4613
THE BRISTOL COMPANY, WATERBURY, CONN. U.S.A.
Chart
Well 28 No.1
5-17 to 5-23
Clock stopped


BRISTOL'S RECORDING PRESSURE GAUGE
THE BRISTOL COMPANY, WATERBURY, CONN. U.S.A.
POUNDS PER SQUARE INCH
Chart
Well
28 No. 1
5-24 to 5-30
4613
THURSDAY
FRIDAY
SATURDAY
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
NIGHT
A.M.
NOON
P.M.
12
3
6
9
500
1000
1500
2000
2500
3000


FRIDAY
SATURDAY
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
NOON
NIGHT
A.M.
P.M.
BRISTOL'S RECORDING
PRESSURE GAUGE
POUNDS PER SQUARE INCH
Chart
4613
THE BRISTOL COMPANY
WATERBURY, CONN.
U.S.A.


FRIDAY
SATURDAY
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
NOON
NIGHT
A.M.
P.M.
BRISTOL'S RECORDING
POUNDS PER SQUARE INCH
Chart
4613
PRESSURE GAUGE
THE BRISTOL COMPANY
WATERBURY, CONN.
U.S.A.


SATURDAY
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
A.M.
P.M.
NOON
NIGHT
BRISTOL'S RECORDING
POUNDS PER SQUARE INCH
Chart
4613
THE BRISTOL COMPANY,
WATERBURY, CONN.
U.S.A.
PRESSURE GAUGE
24 hr. flow period
28-1 Commingled


SATURDAY
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
NIGHT
A.M.
NOON
P.M.
BRISTOL'S RECORDING
POUNDS PER SQUARE INCH
ON: 7-1-65
9th AM.
Chart 4613
Pat. zone producing
28-1 Com
THE BRISTOL COMPANY,
WATERBURY, CONN.
U.S.A.
PRESSURE GAUGE

CONOCO

CONTINENTAL OIL COMPANY

P. O. Box 3312
Durango, Colorado
August 11, 1964

New Mexico Oil Conservation Commission
P. O. Box 2088
Santa Fe, New Mexico

Attention: Mr. A. L. Porter - Secretary Director

Gentlemen:

A hearing before the New Mexico Oil Conservation Commission is requested for the purpose of presenting application by Continental Oil Company to install a downhole commingling tool on a test basis in an existing Gallup-Dakota dual-oil completion well. The test well is Jicarilla 28 Well No. 1, located in Unit J, Section 28, T25N, R4W, Rio Arriba County, New Mexico.

The two sources of supply are commonly owned and the proposed downhole installation is intended to prevent communication between the two reservoirs at all times. Application on a one-well test basis is proposed so that data and procedures for such tests as packer leakage and communication tests and production allocation tests can be established. The commingling installation will be observed to determine the effectiveness of the installation.

The primary purpose of the installation and testing is to esbablish a method whereby further development of the 16-section West Lindrith block in T25N, R4W, can be economically justified. Past producing histories indicate that further development cannot be economically justified by conventional single and dual completion methods and present producing methods.

The following data and exhibits are attached for preliminary information:

1. Lease plat showing wells on the lease and pools from which each are producing.

2. Data requirements for surface commingling installations.

3. Log of Jicarilla 28 Well No. 1, showing formation tops and location of present retainer production packer and perforations in the Gallup and Dakota formation.

4. Schematic diagram of Otis Engineering Corporation's "Dual Flow Choke Assembly" downhole commingling tool.

5. Schematic diagram showing present and proposed installations in Jicarilla 28 Well No. 1.

6. Composite Performance Curve for a typical Jicarilla Gallup and Dakota well.

If additional information is required, please advise.

Very truly yours,

H. D. Haley
District Manager
Durango District
Production Department

GAB/ca

cc: Mr. E. A. Austin, Continental Oil Company, Denver, Colorado (2)
U. S. Geological Survey, Roswell, New Mexico (1)

DATA REQUIRED FOR SURFACE COMMINGLING INSTALLATIONS

Average Daily Oil Production for 90-Day Period:

Jicarilla 26 Well No. 1	Gallup	Dakota
May	13 BOPD	9 BOPD
June	13 BOPD	5 BOPD
July	10 BOPD	8 BOPD

Top Unit Allowable: Gallup - 124 BOPD
Dakota - 104 BOPD
Crude Purchaser: Llaves Pipeline Co. - Farmington, New Mexico
Royalty Interest Owner: Jicarilla Apache Tribe
Liquid Hydrocarbon Gravities: Gallup - 44.4° API
Dakota - 48.4° API
Commingled Liquid Hydrocarbon Gravity - 46° API
Commingled gravity on adjacent lease (Jicarilla 22) over a six-month period has averaged 45.3° API.

Value of 44.4° API Crude = $2.35 per barrel
Value of 48.4° API Crude = $2.35 per barrel less $.08 = $2.27
Value of 46° API Crude = $2.35 per barrel less $.02 = $2.33

Anticipated Producing Rates: Gallup - 14 BOPD
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Value Calculations: Gallup 14 BOPD x $2.35 = $32.90
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The value of the commingled production will not be less than the value of the production from each common source of supply.

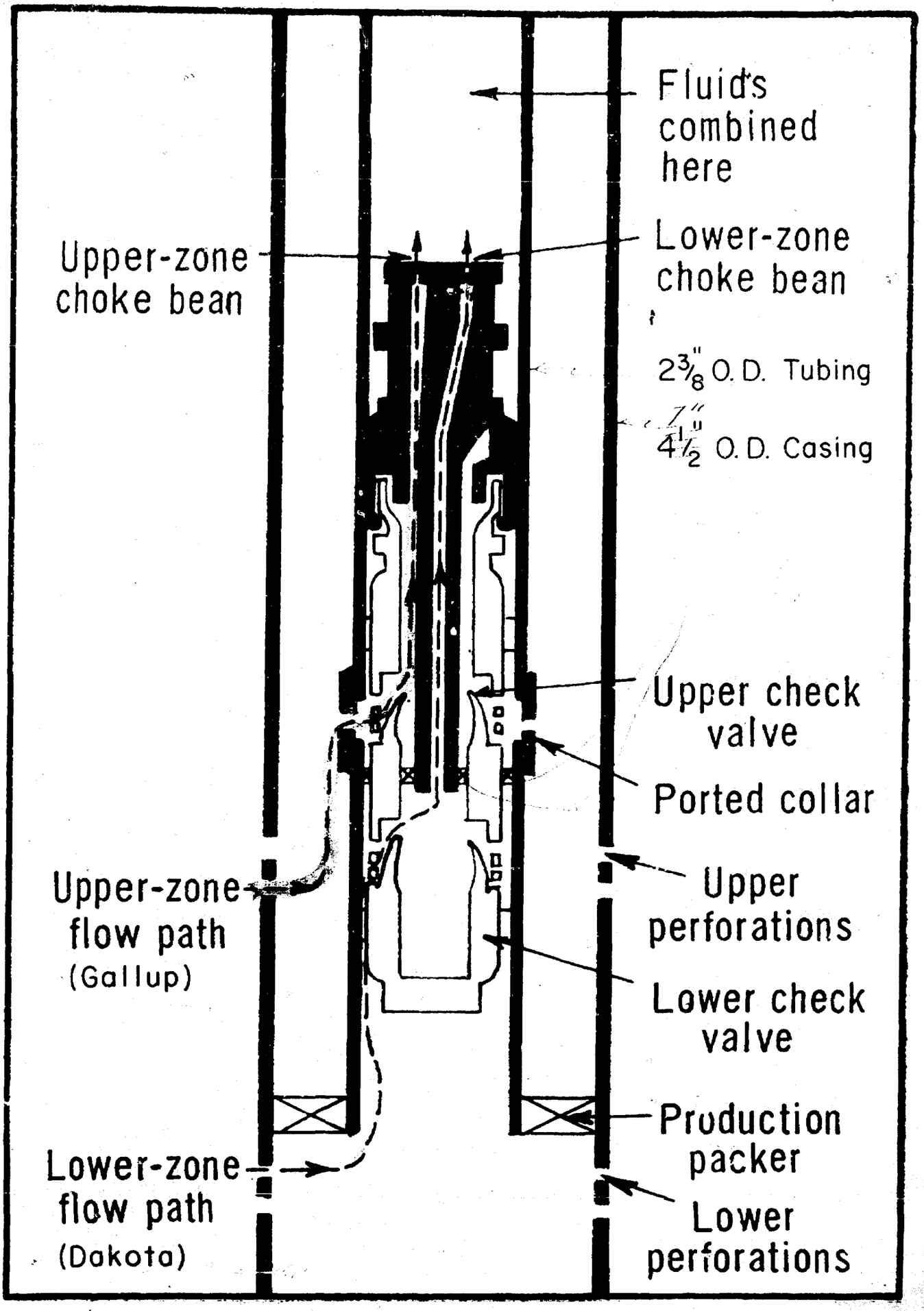
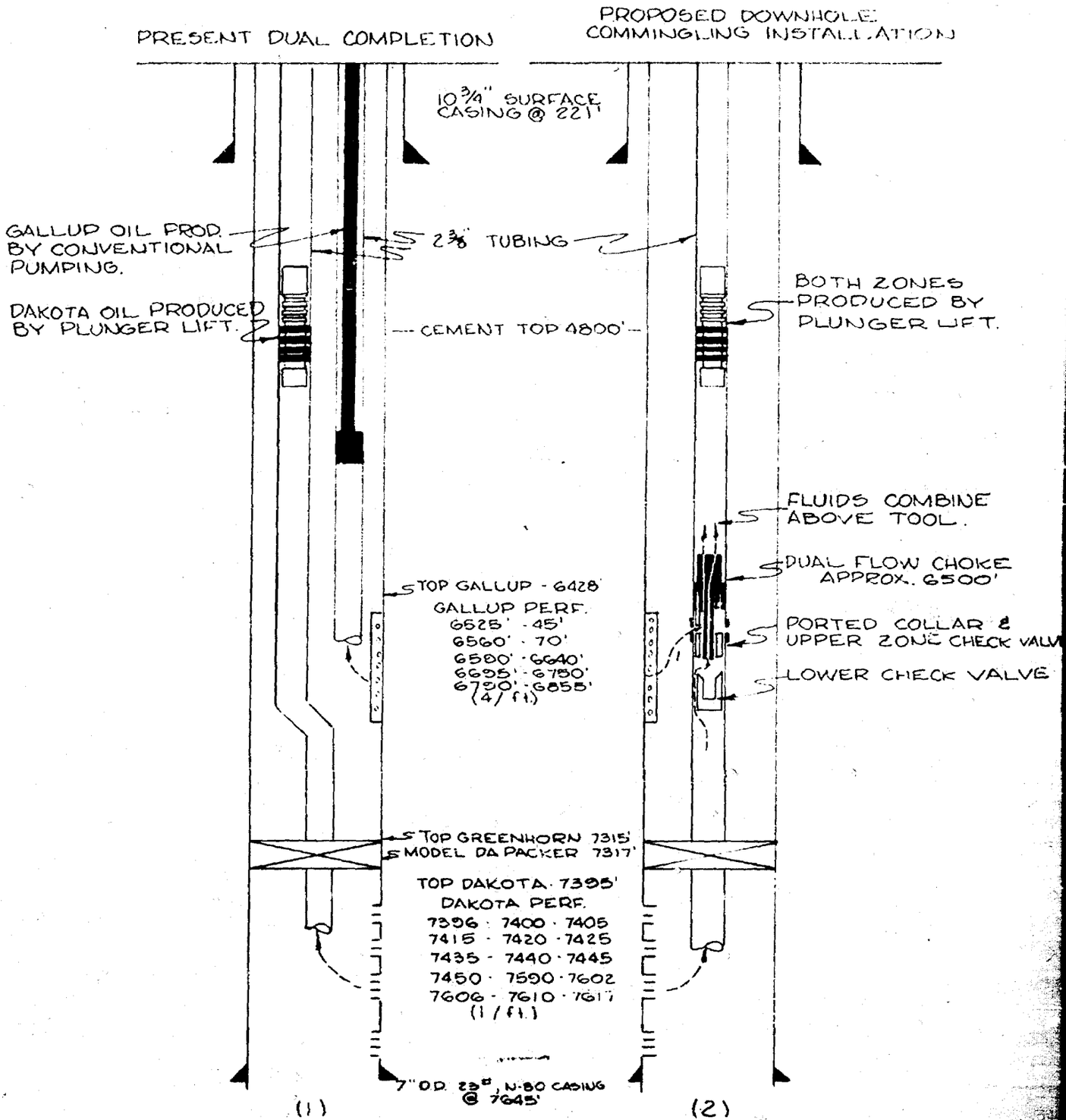


FIGURE NO. 7

Schematic diagram showing installation of Otis "Dual flow choke assembly" for dual zone downhole commingling.

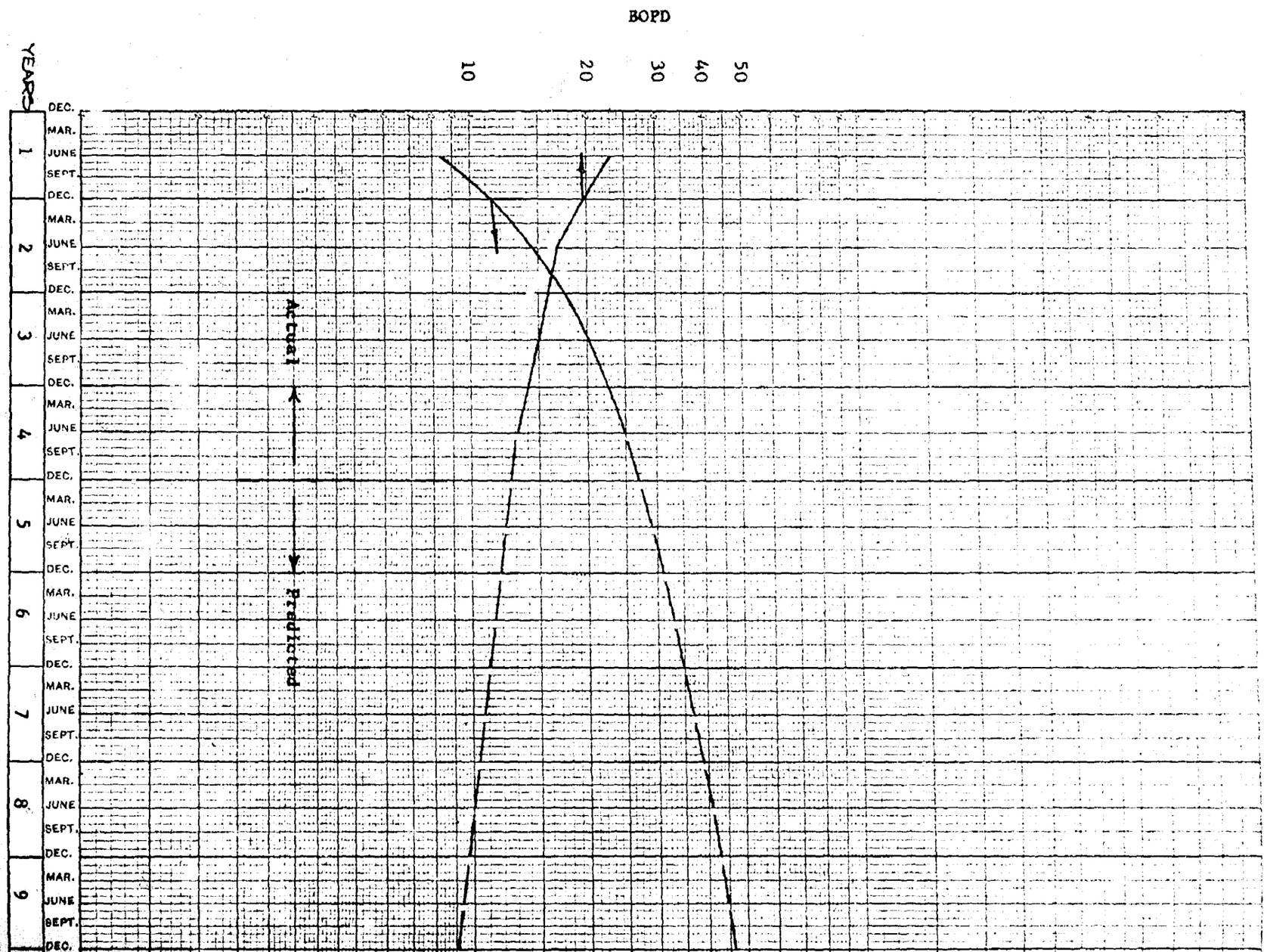


JICARILLA 28 WELL No. 1

SCHEMATIC DIAGRAM SHOWING PRESENT CONVENTIONAL DUAL GALLUP DAKOTA COMPLETION(1) AND PROPOSED INSTALLATION OF "DUAL FLOW CHOKE ASSEMBLY" DUAL ZONE DOWNHOLE COMMINGLING(2).

NO. 4172. TWENTY YEARS BY MONTHS X 3 3-INCH CYCLES RATIO RULING.

CODEX BOOK COMPANY, INC. NORWOOD, MASSACHUSETTS

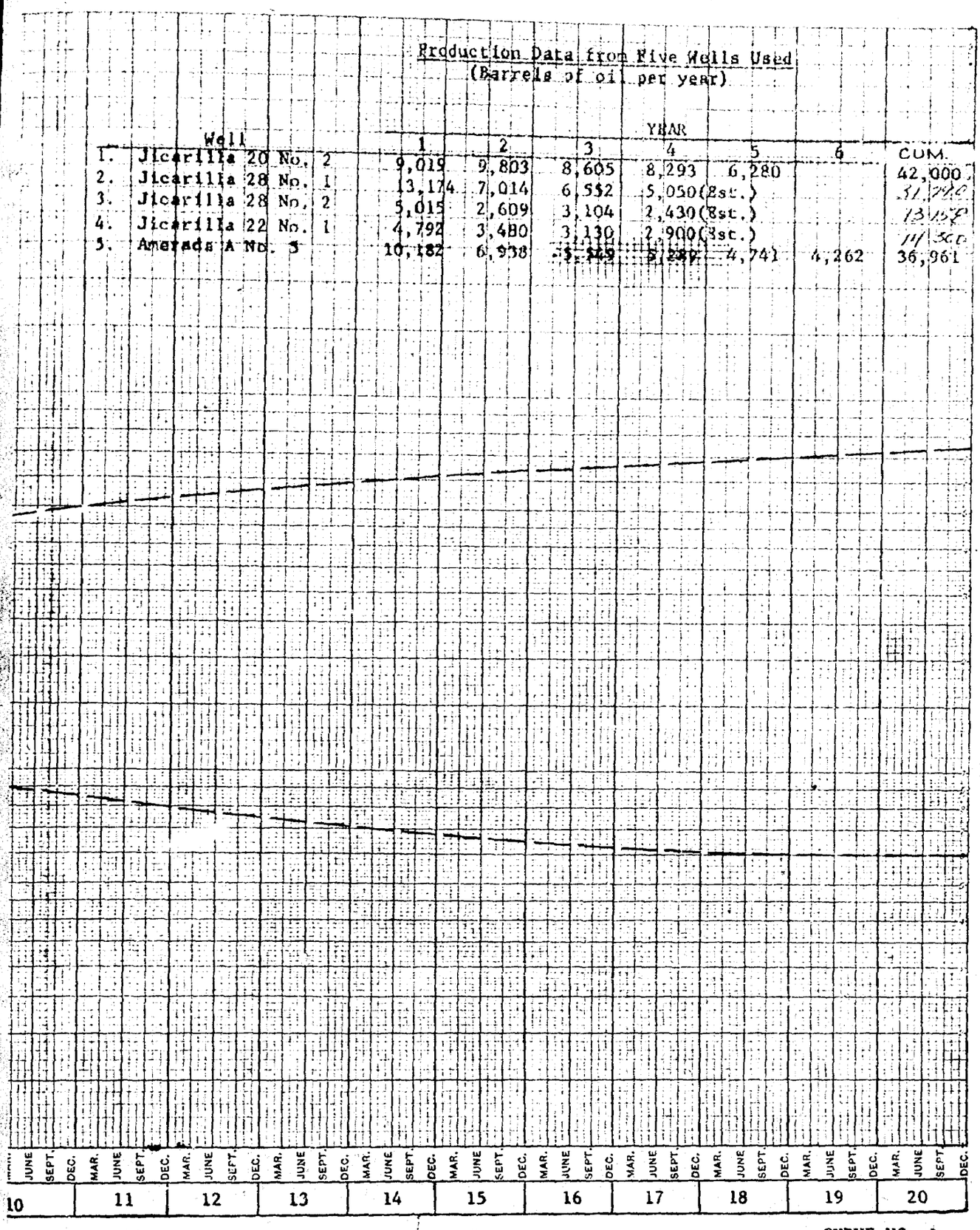


COMPOSITE - TYPICAL WEST LINDRITH GALLUP WELL

Rio Arriba County, New Mexico

Production Data from Five Wells Used
(Barrels of oil per year)

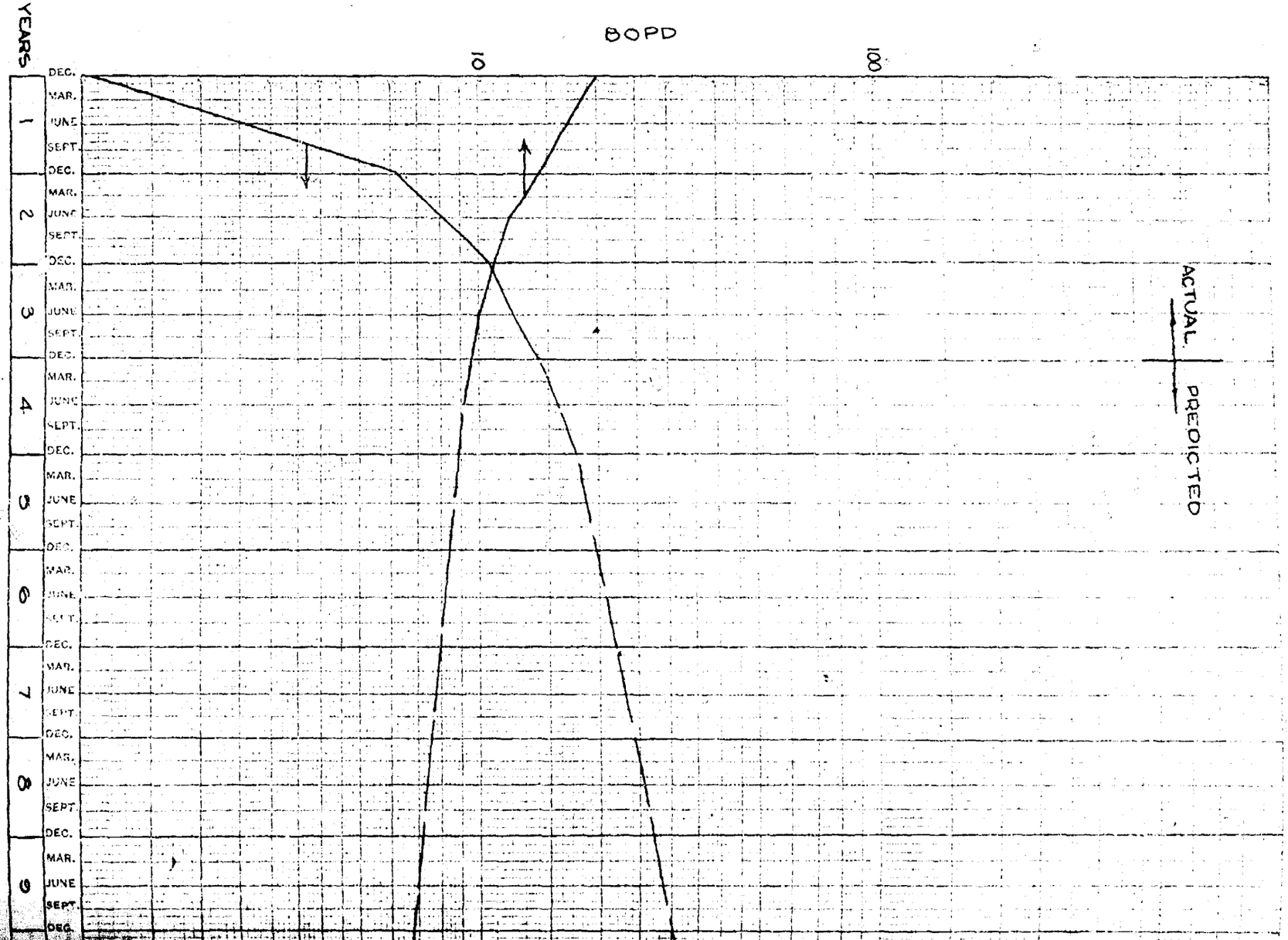
Well	YEAR 1	2	3	4	5	6	CUM.
1. Jicarilla 20 No. 2	9,019	9,803	8,605	8,293	6,280		42,000
2. Jicarilla 28 No. 1	13,174	7,014	6,552	5,050(8st.)			31,790
3. Jicarilla 28 No. 2	5,015	2,609	3,104	2,430(8st.)			13,158
4. Jicarilla 22 No. 1	4,792	3,480	3,130	2,900(8st.)			14,302
5. Amerada A No. 3	10,182	6,938	5,469	5,289	4,741	4,262	36,961



CURVE NO. 1

NO. 4172. TWENTY YEARS BY MONTHS X 3 3-INCH CYCLES RATIO RULING.

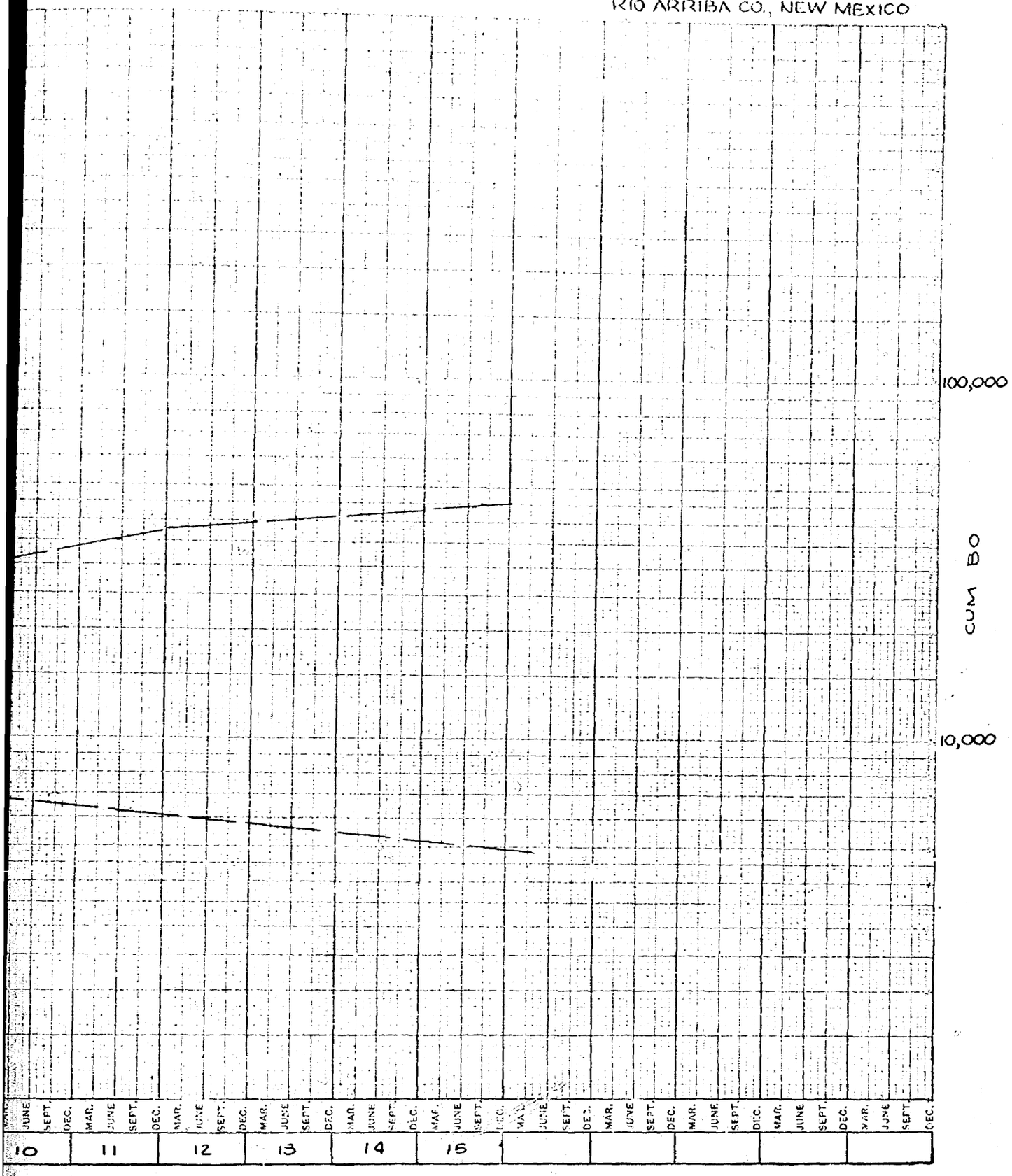
CODEX BOOK COMPANY, INC., NORWOOD, MASSACHUSETTS



WEST LINDRITH DAKOTA

TYPICAL WELL

RIO ARRIBA CO., NEW MEXICO



Curve No. 2

R-4-W

T 25 N

18 17 16 15

19 20 21 22

Jicarilla 20 Lease

Jicarilla 22 Lease

30 29 28 27

Amerada A-5

31 32 33 34

Jicarilla 30 Lease

Jicarilla 28 Lease

Northwest 16-2

Johnston 1-1

Johnston 3-9

Northwest 15-11

LEGEND

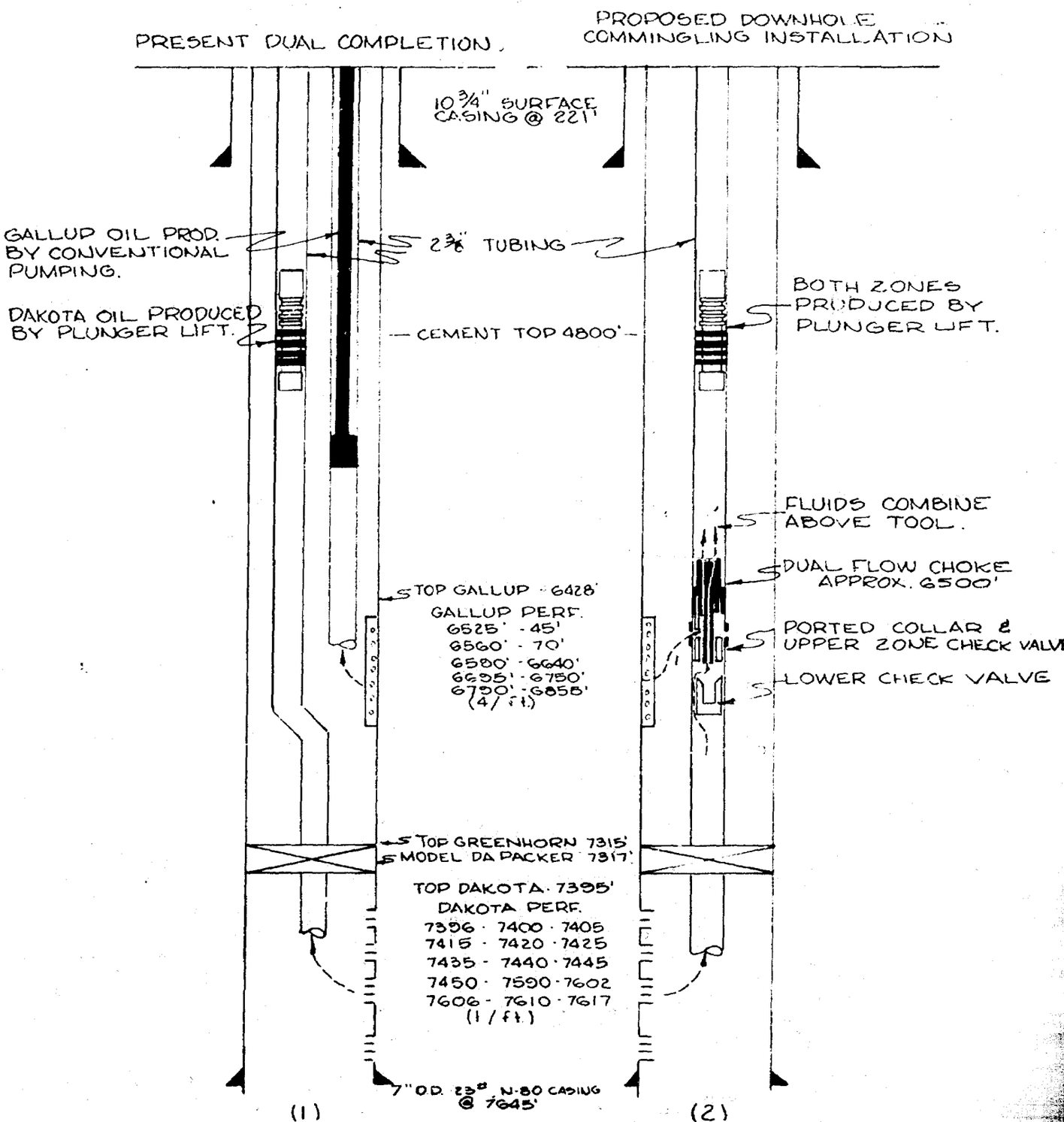
- GALLUP OIL WELL
- DAKOTA - GALLUP DUAL COMPLETION

CONTINENTAL OIL COMPANY

PRODUCTION DEPARTMENT

DRAWN	SCALE 1" = 4000'	FILE NO.
CHECKED	DATE	
APPROVED	SHEET ____ OF ____	

WEST LINDRITH BLOCK
Rio Arriba Co., New Mexico



JICARILLA 28 WELL No. 1

SCHEMATIC DIAGRAM SHOWING PRESENT CONVENTIONAL DUAL GALLUP DAKOTA COMPLETION(1) AND PROPOSED INSTALLATION OF "DUAL FLOW CHOKE ASSEMBLY" DUAL ZONE DOWNHOLE COMMINGLING(2).

Revised 11-1-58

Well No.

County

Pool (Upper Completion) Pool (Lower Completion)

Upper Compl.	Hour, date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)
Lower Compl.	Hour, date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)

MID-TEST SHUT-IN PRESSURE DATA

Commenced at (hour, date)** Zone producing (Upper Lower):

Time (hour, date)	Lapsed time since **	Pressure Upper Compl.	Pressure Lower Compl.	Prod. Zone Temp.	Remarks

Production rate during test
Oil: BOPD based on Bbls. in Hrs. Grav. GOR
Gas: MCFPD; Tested thru (Orifice or Meter):

MID-TEST SHUT-IN PRESSURE DATA

Upper Compl.	Hour, date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)
Lower Compl.	Hour, date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)

WELL TEST NO. 2

Commenced at (hour, date)** Zone producing (Upper Lower):

Time (hour, date)	Lapsed time since **	Pressure Upper Compl.	Pressure Lower Compl.	Prod. Zone Temp.	Remarks

Production rate during test
Oil: BOPD based on Bbls. in Hrs. Grav. GOR
Gas: MCFPD; Tested thru (Orifice or Meter):

REMARKS:

Packer-LEAKAGE TEST PRIOR TO INSTALLATION OF OTIS "DUAL FLOW CHOKE"

I hereby certify that the information herein contained is true and complete to the best of my knowledge.

Approved: 1-20-1965
New Mexico Oil Conservation Commission

By

Title

Operator Continental Oil Company

By FRED VAN MATTE

Title Marketing Engineer

Date January 18, 1965

RECEIVED
JAN 20 1965
OIL CON. COM.
DIST. 3

EXHIBIT No. 1

NEW MEXICO OIL CONSERVATION COMMISSION

Revised 11-1-58

NORTHWEST NEW MEXICO PACKER-LEAKAGE TEST

Operator _____ Lease _____ Well No. _____

Location of Well: Unit _____ Sec. _____ Twp. _____ Rge. _____ County _____

	Name of Reservoir or Pool	Type of Prod. (Oil or Gas)	Method of Prod. (Flow or Art. Lift)	Prod. Medium (Tbg. or Csg.)	Choke Size
Upper Completion					
Lower Completion					

PRE-FLOW SHUT-IN PRESSURE DATA

	Hour, Date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)
Upper Compl.				
Lower Compl.				

FLOW TEST NO. 1

Commenced at (hour, date) _____ Zone producing (Upper or Lower): _____

Time (hour, date)	Lapsed time since **	Pressure Upper Compl.	Pressure Lower Compl.	Prod. Zone Temp.	Remarks

Production rate during test

Oil: _____ BOPD based on _____ Bbls. in _____ Hrs. _____ Grav. _____ GOR _____

Gas: _____ MCFPD; Tested thru (Orifice or Meter): _____

MID-TEST SHUT-IN PRESSURE DATA

	Hour, date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)
Upper Compl.				
Lower Compl.				

FLOW TEST NO. 2

Commenced at (hour, date) _____ Zone producing (Upper or Lower): _____

Time (hour, date)	Lapsed time since **	Pressure Upper Compl.	Pressure Lower Compl.	Prod. Zone Temp.	Remarks

Production rate during test

Oil: _____ BOPD based on _____ Bbls. in _____ Hrs. _____ Grav. _____ GOR _____

Gas: _____ MCFPD; Tested thru (Orifice or Meter): _____

REMARKS: Packer Leakage Test after Installation of Cable "and Flow Checks" in accordance with Commission Order No. R-2034.

I hereby certify that the information herein contained is true and complete to the best of my knowledge.

Approved: 2-24 1965

New Mexico Oil Conservation Commission

By _____

Title _____

Operator Continental Oil Company

By _____

Title District Superintendent

Date 2-22-65

RECEIVED
DURANGO PROD.
MAR 9 1965

OIL CON. COM.
DIST. 3

FEB 24

OIL CON. COM.

EXHIBIT #2

Mail(s) File

NEW MEXICO OIL CONSERVATION COMMISSION

Revised 11-1-58

MULTIPLE COMPLETION MULTI-POINT BACK PRESSURE TEST

Pool

Operator Address Lease No.

Unit Letter Section Township Range County

	Upper Compl. (Tbg. or Csg.)	Perforations	Choke Size
Upper Compl.			
Lower Compl.			

MID-TEST SHUT-IN PRESSURE DATA

	Hour, date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)
Upper Compl.				
Lower Compl.				

FLOW TEST NO. 1

Commenced at (hour, date)** Zone producing (Upper or Lower):

Time (hour, date)	Lapsed time since **	Pressure Upper Compl.	Pressure Lower Compl.	Prod. Zone Temp.	Remarks

Production rate during test

Oil: BOPD based on Bbls. in Hrs. Grav. GOR

Gas: MCFPD; Tested thru (Orifice or Meter):

MID-TEST SHUT-IN PRESSURE DATA

	Hour, date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)
Upper Compl.				
Lower Compl.				

FLOW TEST NO. 2

Commenced at (hour, date)** Zone producing (Upper or Lower):

Time (hour, date)	Lapsed time since **	Pressure Upper Compl.	Pressure Lower Compl.	Prod. Zone Temp.	Remarks

Production rate during test

Oil: BOPD based on Bbls. in Hrs. Grav. GOR

Gas: MCFPD; Tested thru (Orifice or Meter):

REMARKS:

I hereby certify that the information herein contained is true and complete to the best of my knowledge.

Approved: 19

New Mexico Oil Conservation Commission

By

Title

Operator

By

Title

Date

RECEIVED
DUAL COMPL. PROD.
MAR 9 1965

FEB 4

OIL

EXHIBIT #2

cc: File

Revised 11-1-58

			SI press.		Stabilized? (Yes or No)
			SI press.		Stabilized? (Yes or No)

Time (hour, date)	Lapsed time since **	Pressure		Prod. Zone	Remarks

Production rate during test
Oil: ____ BOPD based on ____ Bbls. in ____ Hrs. ____ Grav. ____ GOR ____
Gas: ____ MCFPD; Tested thru (Orifice or Meter): ____

MID-TEST SHUT-IN PRESSURE DATA

Upper Zone	Hour, date Shut-in 6-11-65	Length of time shut-in 167 1/2 hrs.	SI press. paig 774		Stabilized? (Yes or No) No
Lower Zone	Hour, date Shut-in 6-3-65	Length of time shut-in 384 hrs.	SI press. paig 1255		Stabilized? (Yes or No) No

FINAL TEST NO. 2

Commenced at (hour, date)** 6-18-65 6:40 A.M. Zone producing (Upper or Lower):

Time (hour, date)	Lapsed time since **	Pressure		Prod. Zone	Remarks
		Upper Zone	Lower Zone		
6:40 A.M. 6-18-65	0	774	1255		Dead weight gauge
9:00 A.M. 6-18-65	20 min.	830	885		Two-pen recorder Intermitter Open
2:40 P.M. 6-18-65	5 hrs.	869	950		Two-pen recorder Intermitter closed
8:30 A.M. 6-19-65	24 hrs.	880	939		Dead weight gauge Intermitter closed
9:05 A.M. 6-22-65	96 hrs.	890	887		Dead weight gauge Intermitter closed
9:20 A.M. 6-22-65	96 hrs.	890	885		Dead weight gauge Intermitter Open

Production rate during test
Oil: 26 BOPD based on 24 Bbls. in 24 Hrs. ____ Grav. 49 GOR 7462
Gas: 194 MCFPD; Tested thru (Orifice or Meter): Meter

REMARKS: Packer leakage test at end of Otis "Dual Flow Choke" test installation period in accordance with Commission Order No. R-2924

I hereby certify that the information herein contained is true and complete to the best of my knowledge.

Approved: 6-25 1965
New Mexico Oil Conservation Commission

By ____

Title ____

Operator Continental Oil Company

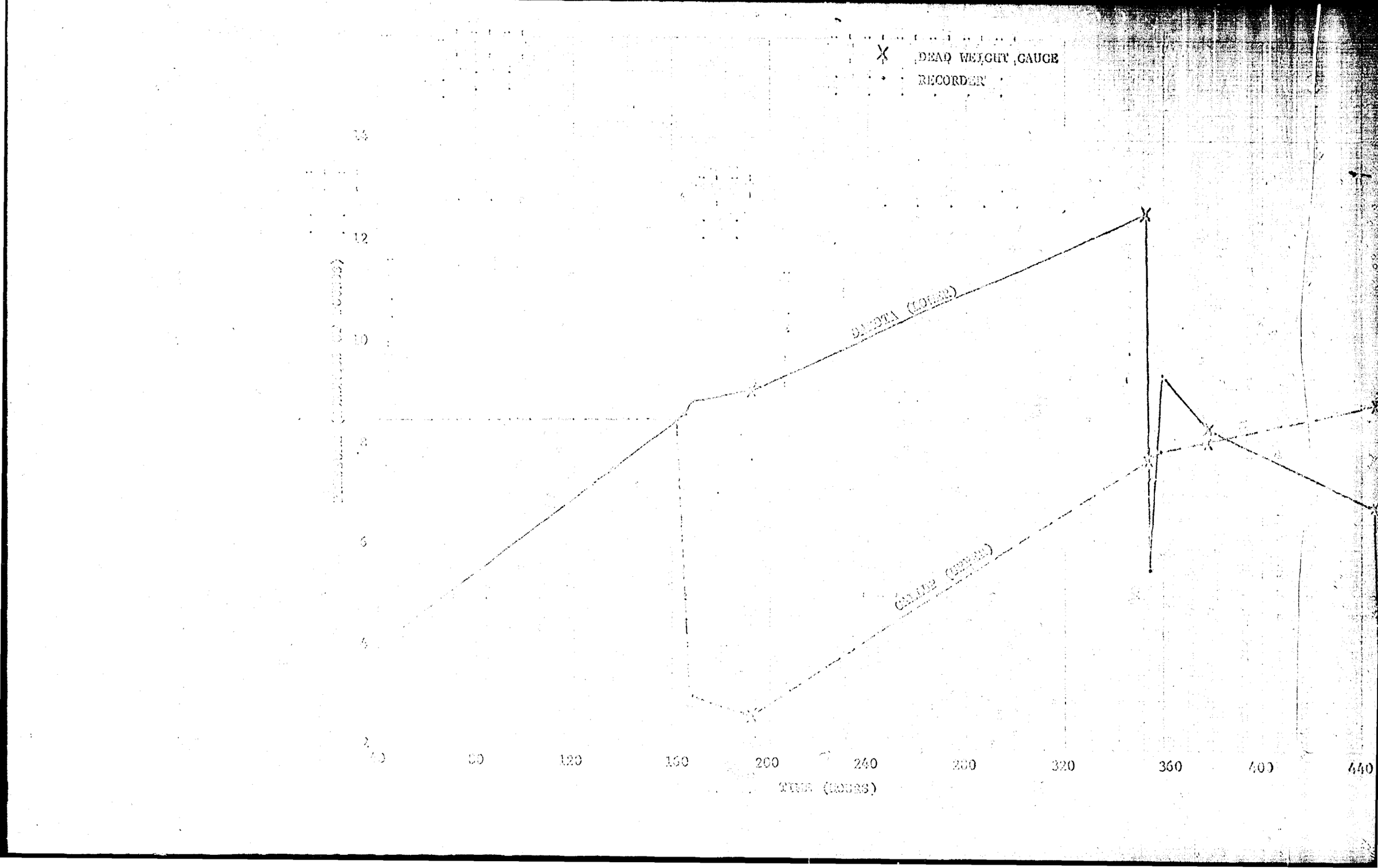
By ____

Title District Engineer

Date June 23, 1965

NMOCC(3) HDH JMG

EXHIBIT #3


DEAD WEIGHT GAUGE
RECORDER
12
10
8
6
4
2
0
120
160
200
240
280
320
360
400
440
TIME (HOURS)

Revised 11-1-58

Well No. 1

Unit Letter P Sec. 10 Twp. 20S Rge. 37E County Lea Pool Undesignated (Gas on Comp.)

Upper Compl.	Hour, date Shut-in 9:10 A.M. 6-11-65	Length of time shut-in 117 1/2 hrs.	SI press. psig 774
Lower Compl.	Hour, date Shut-in 9:00 A.M. 6-8-65	Length of time shut-in 334 hrs.	SI press. psig 1255

Both Zones Shut-in (Upper and Lower)

Upper (Tbg.)	Lower (Csg.)	Upper Compl.	Lower Compl.	Prod. Zone Temp.	Remarks
6-10-65 9:10 A.M.	2 hrs.	775	1260		Two-pen recorder
6-10-65 3:10 P.M.	6 hrs.	810	990		Two-pen recorder
6-11-65 9:10 A.M.	24	830	815		Dead weight pressure

Production rate during test
Oil: 0 BOPD based on 0 Bbls. in 24 Hrs. Grav. GOR
Gas: 57 MCFPD; Tested thru (Orifice or Meter): Meter

MID-TEST SHUT-IN PRESSURE DATA

Upper Compl.	Hour, date Shut-in 9:10 A.M. 6-11-65	Length of time shut-in 117 1/2 hrs.	SI press. psig 774	Stabilized? (Yes or No) No
Lower Compl.	Hour, date Shut-in 9:00 A.M. 6-8-65	Length of time shut-in 334 hrs.	SI press. psig 1255	Stabilized? (Yes or No) No

FLOW TEST NO. 2

Commenced at (hour, date) ** 6-11-65 Zone producing (Upper or Lower):

Time (hour, date)	Lapsed time since **	Upper Compl.	Lower Compl.	Prod. Zone Temp.	Remarks
6:40 A.M. 6-10-65	0	774	1255		Dead weight gauge
9:00 A.M. 6-10-65	30 min.	800	555		Two-pen recorder Intermitter Open
12:40 P.M. 6-10-65	3 hrs.	820	960		Two-pen recorder Intermitter closed
6:30 A.M. 6-10-65	24 hrs.	810	680		Dead weight gauge Intermitter closed
6:15 A.M. 6-22-65	96 hrs.	890	687		Dead weight gauge Intermitter closed
9:30 A.M. 6-22-65	96 hrs.	890	255		Dead weight gauge Intermitter Open

Production rate during test
Oil: 96 BOPD based on 25 Bbls. in 24 Hrs. Grav. 49 GOR 7462
Gas: 184 MCFPD; Tested thru (Orifice or Meter): Meter

REMARKS: Packer Leakage test at end of Otis "Dual Flow Choke" test installation period in accordance with Commission Order No. R-2824

I hereby certify that the information herein contained is true and complete to the best of my knowledge.

Approved: G-25 1965
New Mexico Oil Conservation Commission

By

Title

Operator Continental Oil Company

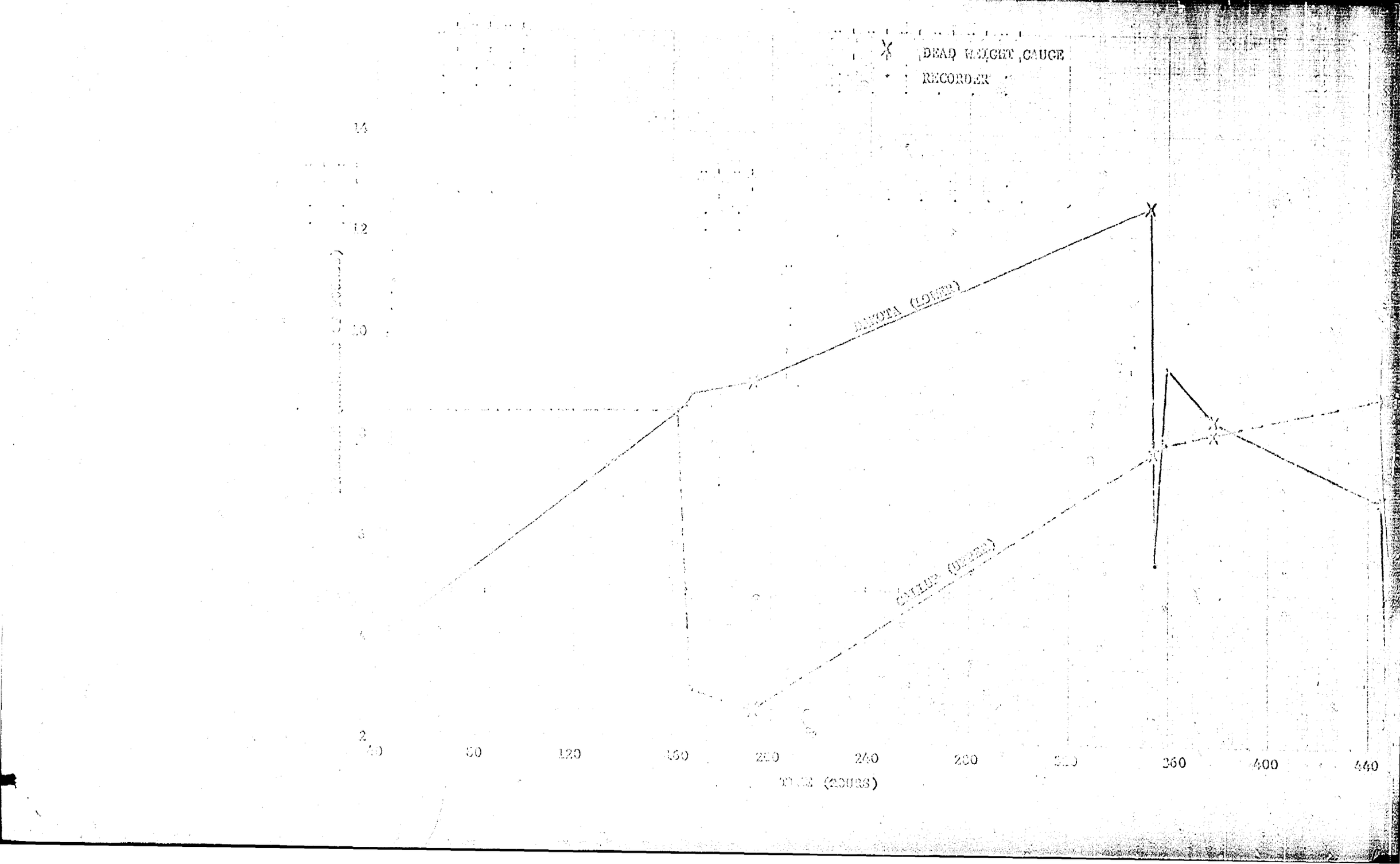
By

Title District Engineer

Date June 23, 1965

NMOCC(3) HDH JMG

EXHIBIT #3


DEAD WEIGHT GAUGE
RECORDER
14
12
10
8
6
4
2
80
120
160
200
240
280
320
360
400
440
DAKOTA (LOWER)
COTTER (UPPER)

JICARILLA 28 WELL NO. 1
COMBINED PRODUCTION PERFORMANCE - 1963-1964
GALLUP (PUMP) - DAKOTA (PLUNGER LIFT)

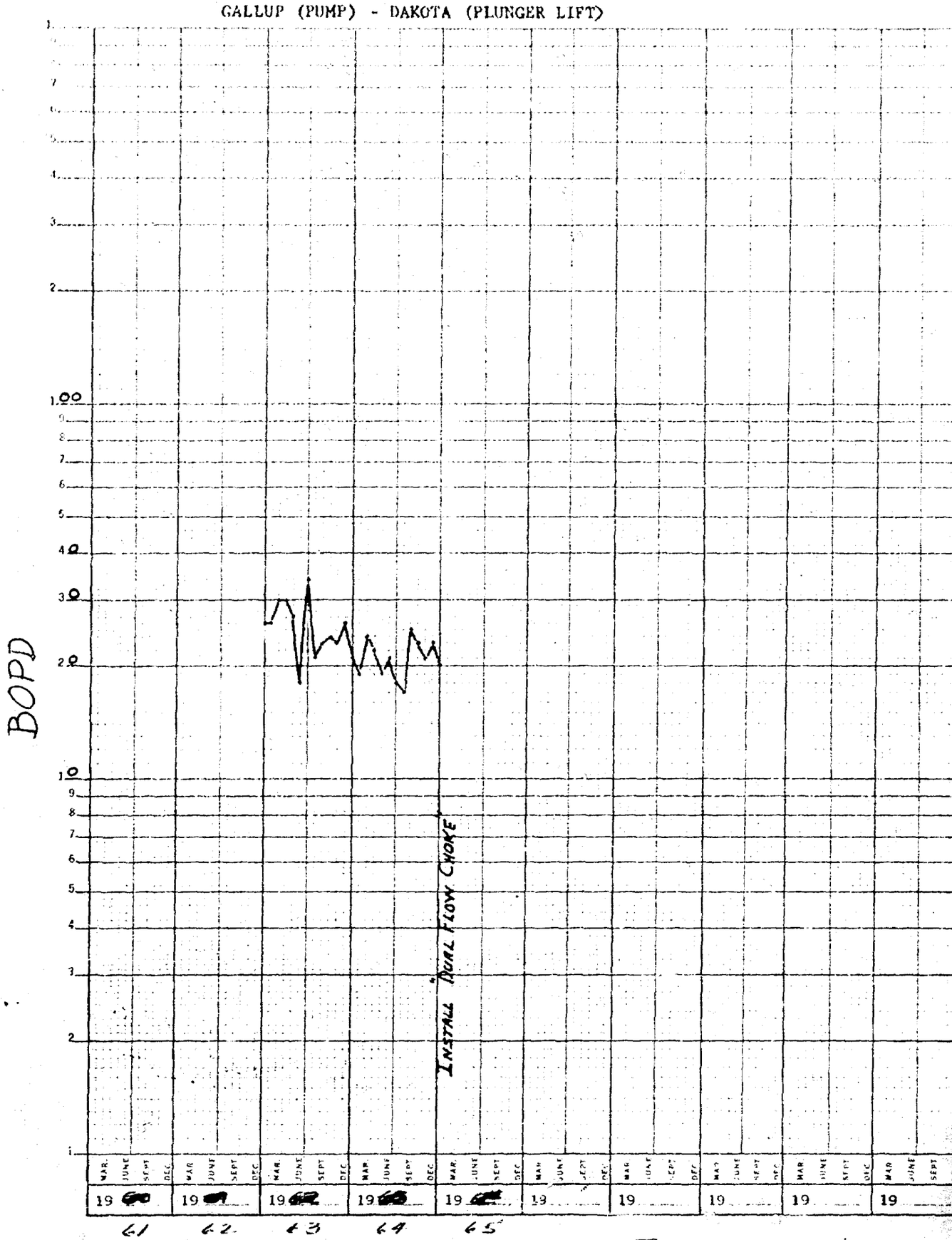


EXHIBIT No. 6

BEFORE EXAMINER NUTTER
OIL CONSERVATION COMMISSION
EXHIBIT NO. 6
CASE NO. 3113

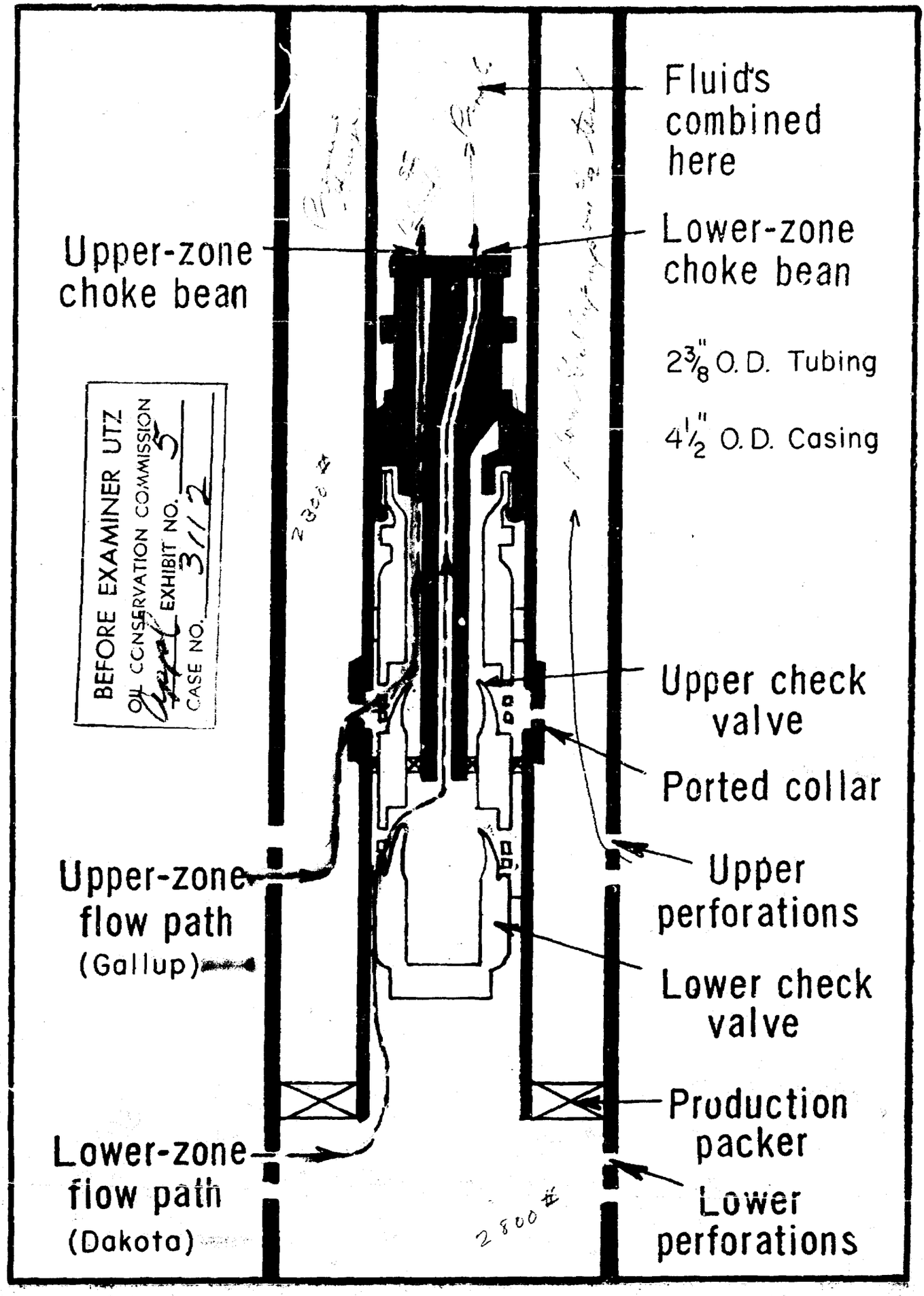


FIGURE NO. 7

Schematic diagram showing installation of Otis "Dual flow choke assembly" for dual zone downhole commingling.

4-65 PC

AVAILABLE COPY

DATE 7-29-65

TO Denny Watts -

FROM George Brown - Continental Oil Co.

Attached is my summary which followed my recommendations to the Commission.

A copy of the Recommendations is being forwarded to you by Mr. C.R. Roberts, the attorney.

If you need any additional information or clarification on any items, please let me know or call 24-7-2580 in Durango, Colorado. Code 303.

Summary

In my opinion
It is ~~believed~~ the data presented conclusively shows that the Dual Flow downhole choke assembly can be effectively used to produce commingled hydrocarbons from two separate reservoirs simultaneously through a single tubing string without communicating between the two zones. The tests show that leakage does not occur through the check assembly, and that annual production allocation tests and packer leakage tests can be satisfactorily performed in accordance with NMOCC requirements for commingling of marginal zone wells.

The tests show that excess energy from the lower Dakota zone can be effectively utilized to lift production from the weaker Gallup zone which previously required artificial lift by pumping.

By minimizing test requirements, operating costs over conventional dual completion methods can be greatly reduced and current income from a marginal well such as 28 well No. 1 can be increased.

By use of ~~this tool~~ the Dual Flow Choke, future well costs for the Jicarilla Apache West Lindrith leases can be greatly reduced and further development of the Gallup and Dakota reservoirs ~~may become~~ would be economically feasible. Use of the tool in this area will also prolong the economic limit of both zones and result in an increase in ultimate recovery from both reservoirs thus preventing unnecessary waste, and recovery of considerable oil reserves that would otherwise not be recovered

August 2, 1965

Mr. D. S. Nutter, Chief Engineer
New Mexico Oil Conservation Commission
P. O. Box 871
Santa Fe, New Mexico

RE: Case 3112, Hearing of July 28, 1965, in regard to Order No. R-2824 authorizing Gallup-Dakota commingling in the wellbore of Jicarilla 28 Well No. 1, Rio Arriba County, New Mexico

Dear Mr. Nutter:

In response to your request at the above captioned hearing, I am providing you the recommendations of Continental Oil Company as stated by Mr. George Brown at the close of direct examination of him by me. The following is the verbatum response of Mr. Brown.

"Initially we request and recommend that Continental Oil Company be permitted here today to continue producing the Jicarilla 28 Well No. 1 with the dualflow choke installed in it until such time as the Commission announces its ruling with respect to the hearing today.

We recommend that the Commission grant Continental Oil Company approval to install such a dualflow choke in the Jicarilla 28 Well No. 1 and to install such a dualflow choke in any existing Gallup-Dakota marginal oil wells located on its acreage in the West Lindrith Field and in any Gallup-Dakota marginal oil wells which may be drilled on its acreage in the West Lindrith Field,

the acreage being shown on Exhibit 1 of the hearing of September 30, 1964 and specifically that:

(1) The Commission make provision for administrative approval of future downhole commingling installations by use of the dualflow choke in existing Gallup-Dakota marginal oil wells and any Gallup-Dakota marginal oil wells which may be drilled within the Continental Oil Company's West Lindrith acreage which consists of four Jicarilla apache leases covering Sections 15 through 22 and 27 through 34, T 25 N, R 4 W, Rio Arriba County, New Mexico;

(2) Application for such administrative approval be filed in triplicate with the Commission and such applications contain detailed data as to gravity, value and volume of the liquid hydrocarbons from each pool, expected gravity and value of the commingled liquid-hydrocarbon production, a schematic diagram of the proposed installation, a plat showing the location of all wells on applicant's lease and the pool from which each well is producing, and whether the actual commercial value of the commingled production will be less than the sum of the values of the production from each common source of supply and if so how much less;

(3) Allocation of production to the Gallup and Dakota zones be by the subtraction method based on annual production tests of the commingled Gallup-Dakota and the Dakota at stabilized production rates;

(4) Continental conduct a packer leakage test and a seal leakage test upon installation of the dualflow choke;

(5) Continental conduct a production test of the commingled Gallup-Dakota and of the Dakota upon installation of the dualflow choke and annually thereafter;

(6) Continental conduct an annual packer leakage test with respect to each well so equipped;

(7) Continental be granted an exception to Rule 303A and any other applicable Rules for the permanent installation of the dualflow choke in the Jicarilla 28 Well No. 1 and in any existing

Gallup-Dakota marginal oil wells or Gallup-Dakota marginal oil wells which may be drilled on Continental Oil Company's West Lindrith acreage, the location of which I have already described."

If we can provide you additional information, please do not hesitate to call on us.

Best Personal Regards,

Original Signed
CHARLES R. ROBERTS

Charles R. Roberts
Attorney

CRR:kn

cc: Mr. J. M. Durrett, Jr.
Mr. George Brown

bcc: Mr. Denny Watts

EXHIBIT NO. 7

7800' - 7" Casing	$ 23,400
11500' - 2 3/8" Tubing (Est)	11,100
Casing fishing head, valves, other miscellaneous casing & tubing equipment (6)	5,500
1-7/8" engine (6)	7,500
6500' cable (6)	4,300
Lufkin Jack pump (6)	600
Intangible Drilling Costs	65,900
Contract Labor	4,000
Production Equipment	3,000
Surface Commingling Equip.	2,000
Sales Taxes	1,800
Miscellaneous	7,000
	$136,100

7800' - 4 1/2" Casing	$11,700
11500' - 2 7/8" Tubing	5,500
Csg. fishing head, valves, etc.	2,500
Wellhead equipment and Permian Flow Choke	4,500
"	"
"	"
Intangible Drilling Costs	63,400
Contract Labor	2,000
Production Equipment	4,000
"	"
Sales Taxes	600
Miscellaneous	500
	$93,100

Difference - $43,000

BEFORE EXAMINER NUTTER
OIL CONSERVATION COMMISSION
EXHIBIT NO. 7
CASE NO. 3112

OIL ALLOCATION

Dakota = $\frac{\text{Dakota bbls.}}{25 \text{ bbls.}}$ X Gross Commingled Production

Gallup = Gross commingled production - Dakota allocated production

Example:
Total commingled production = 750 bbls.

Dakota allocation = $\frac{2}{25}$ X 750 bbls. = 278 bbls.

Gallup allocation = 750 bbls. - 278 bbls. = 472 bbls.

GAS ALLOCATION

Commingled GOR = 6599 : 1
Dakota GOR = 9216 : 1

Example

Theoretical Total Gas Production = 6599 (750 bbls.)	=	4949 MCF
Theoretical Dakota Gas Prod. = 9216 (278 bbls.)	=	2562 MCF
Theoretical Gallup Gas Production (Difference)	=	2387 MCF

Actual Gas Sales = 4635 MCF
Lease Use = 450 MCF
Actual Total Gas = 5085 MCF

Dakota Gas Allocation = 5085 X $\frac{2562}{4949}$ = 2629 MCF

Gallup Gas Allocation (Difference) = 5085 - 2629 = 2456 MCF

Dakota GOR = $\frac{2629}{278}$ MCF = 9457

Gallup GOR = $\frac{2456}{472}$ MCF = 5203

BEFORE EXAMINER NUTTER
OIL CONSERVATION COMMISSION
EXHIBIT NO. 5
CASE NO. 3112

#5

PRODUCTION PERFORMANCE
JICARILLA 28 WELL NO. 1
"DUAL FLOW CHOKE TEST INSTALLATION"

EXHIBIT #

Date	Zone Producing Gallup-Dakota		BOPD	Remarks
1-12-65	SI			Pulling dual tubing strings to install "Dual
13	SI			Flow Choke".
14	SI			Installed tool with Dakota check valve
15	SI			removed for purpose of packer-leakage
16	X	X		test. Produced well from 1-16 to
17	X	X		1-23-65 to clean well up and
18	X	X		recover load oil used to kill well.
19	X	X		
20	X	X		
21	X	X		
22	X	X		
23	SI			SI for packer-leakage - No blanks in tool
24	SI			to test upper check valve.
25	SI			
26	SI			
27	SI			BHP-Gallup-Fluid level survey - 721 psi
28	SI			after 96 hours shut-in.
29	SI			
30	X		0	Flow period No. 1-Gallup up annulus.
31	SI			No oil produced. Made 180 MCF gas. No
2-1-65	SI			blank in Gallup side to prove upper zone
2	SI			check valve. Check valve not leaking.
3	SI			
4	SI			Blanked off Gallup orifice.
5	SI			Dakota BHP-Bomb Survey -1525 psi after
6	SI			320 hrs. SI. BHT -167° F.
7		X	21	Flow period #2-Dakota up tubing. GOR 9906.
8		X	15	Pulled complete tool. Installed Dakota check valve - Gallup blanked. Ran 180 hr. pressure bomb on hanger above tool and below plunger.
9		X	23	Started #1 Production distribution test
10		X	10	at 150 psig back pressure.
11		X	23	Intermitter valve failed - well loaded - bled pressure down.
12		X	15	24 hrs. @ 50 psig back pressure.
13		X	8	24 hrs. @ 50 psig back pressure.
14		X	22	Tried both pressure control & time control
15		X	10	to stabilize producing rates. Unable to
16		X	12	get stabilized rates in seven-day period.
17		X	7	Pulled bomb and orifice assembly. Discovered clock in bomb had not operated. Distribution test data not obtained. Long stabilization period required and wire line costs prohibit distribution type allocation test. Will conduct subtraction test.
18		X	5	Ran orifice assembly with both zones open. Production Commingled.

PRODUCTION PERFORMANCE
JICARILLA 26 WELL NO. 1
"DUAL FLOW CHOKE TEST INSTALLATION"

EXHIBIT
Page 2

Date	Zone Producing Gal.	Dak.	BOPD	MCF	GOR	Remarks
2-19-65	X	X	7	*		*Gas to pit intermittently.
20	X	X	12	*		Plunger on tubing pressure control.
21	X	X	18	*		
22	X	X	-	-		Gas to pit 2-22 to 3-3 attempting
23	X	X	15	*		to draw Dakota down. Gallup zone
24	X	X	12	*		not entering tubing
25	X	X	20	*		
26	X	X	30	*		Gallup now entering tubing. Gas
27	X	X	28	*		continued to pit. FTP 100#.
28	X	X	33	*		Plunger on time cycle control.
3-1-65	X	X	30	*		
2	X	X	33	*		
3	X	X	37	*		
4	X	X	20			Gas to 250# sales system.
5	X	X	23			Plunger 12 trips daily.
6	X	X	27			
7	X	X	25	8-Day	8-Day	
8	X	X	25	Total	Avg.	
9	X	X	25	1117 MCF	5788	
10	X	X	28			
11	X	X	20			8-day Avg. - 24 BOPD, GOR 5788.
12	X	X	22			250# gas sales system.
13	X	X	23			
14	X	X	22	8-Day	8-Day	
15	X	X	23	Total	Avg.	
16	X	X	26	1394 MCF	7337	*Plunger 16 trips daily.
17	X	X	24			
18	X	X	25			
19	X	X	25			8-day Avg. - 24 BOPD, GOR 7337.
20	X	X	27			21-day Avg. (3-3 to 3-24)
21	X	X	25	5-Day	5-Day	BOPD = 24.3
22	X	X	23	Total	Avg.	MCFD = 157.8
				802 MCF	6416	GOR = 6496 : 1
23	X	X	25			*Final 9-day Avg. (3-16 to 3-25)
24	X	X	27			BOPD = 25
						GOR = 6599 : 1
3-25-65			0			Pulled orifice assembly to blank Gallup zone. Pressured up on check assembly. Discovered Dakota check had not been installed. Installed Dakota check.
26			0			Installed blank in Gallup choke.
27			0			Waiting on parts.
28		X	33			Gallup zone blanked off.
29		X	28			FTP - 220#.
30		X	13			
31		X	40			
4-1-65		X	30			
2		X	30			
3		X	22			
4		X	20			
5	?	X	25			Suspect Gallup blank is not holding
6	?	X	22			and both zones producing.
7	?	X	22	8-Day	8-Day	
8	?	X	25	Total	Avg.	
9	?	X	17	1101 MCF	6713	
10	?	X	15			
11	?	X	5			Gas line freeze.
12	?	X	33			

PRODUCTION PERFORMANCE
JICARILLA 28 WELL NO. 1
"DUAL FLOW CHOKE TEST INSTALLATION"

EXHIBIT
Page 3

Date	Zone Producing Gal.	Dak.	BOPD	MCF	GOR	Remarks
4-13-65	?	X	25			
14	?	X	22			
15	?	X	23	8-Day	8-Day	
16	?	X	20	Total	Avg.	
17	?	X	22	1179 MCF	6624	
18	?	X	17			
19	?	X	22			
20	?	X	27			
21	?	X	23	157	6841	
22	X	X	47			Gas to pit. Casing pressure decreased
23	X	X	5			from 575# to 475# indicating Gallup
24	X	X	40			zone blanked off.
25	X	X	57			
26	X	X	52			
27			0			Pulled orifice assembly. Found it
28			0			had not seated in check assembly.
29			0			Ordered another orifice assembly.
30			0			Pulled check assembly to inspect.
5-1-65			0			Reran check. Could not get orifice assembly to seat in check assembly. Unable to retrieve check assembly. Pulled tubing to install tool
2		X	17*			Ran tubing and assembly with Gallup
3		X	8*			blanked off. Dakota producing load
4		X	12*			oil up tubing.
5		X	12*			
6		X	15*			
7		X	15*			
8		X	7*			
9		X	8*			
			* Load oil being recovered.			
10		X	5*			Plunger sticking.
11		X	7*			
12		X	15*			
13		X	5*			
14			0			Plunger stuck - surfaced to inspect.
15			0			Sand on top. SI to blow out sand.
16		X	18*			Gas to pit.
17		X	15*			
18		X	5*			Plunger stuck - changed plungers.
19		X	3*			Gas to pit.
20		X	10*			Gas to pit.
21		X	7*			Gas to pit.
22		X	8*			Gas to sales - FTP 250#.
23		X	10	92	9200	Load oil recovered - started
24		X	10	88	8800	stabilized Dakota producing rate
25		X	10	88	8800	for subtraction method production
26		X	8	78	9750	allocation.
27		X	8	76	9500	
28		X	10	84	8400	
29		X	8	90	11250	
30		X	10	90	9000	
31		X	10	88	8800	
6-1-65		X	8	78	9750	API Gravity - 48.3.
2		X	10	88	8800	11-day Avg. (Dakota) = 9.3 BOPD, GOR 9216.

PRODUCTION PERFORMANCE
JICARILLA 28 WELL NO. 1
"DUAL FLOW CHOKE TEST INSTALLATION"

EXHIBIT
Page 4

Date	Zone Producing Gal.-Dak.	BOPD	MCF	GOR	Remarks
6-3-65	SI	0			Pressure tested check valves to 1500#.
4	SI	0			No leak through check assembly.
5	SI	0			Knocked out bottom plug in check
6	SI	0			assembly making lower zone check
7	SI	0			inoperative. SI for test end packer-
8	SI	0			leakage test.
9	SI	0			
10	X	0	97		Flow period No. 1, Gallup zone up
11	SI	0			annulus.
12	SI	0			
13	SI	0			
14	SI	0			
15	SI	0			
16	SI	0			
17	SI	0			
18	X	26	194		Flow period No. 2 - Dakota up tubing.
19	X	22			
20	X	20			
21	X	13			
22	X X	43			Pull complete tool. Install bottom
23	X X	35			plug in check assembly. Ran check
24					assembly. Zones commingled. Produce until 7-28-65.

Revised 11-1-58

Operator _____ Well No. _____

Location of Well: Unit _____ Sec. _____ Twp. _____ Rge. _____ County _____

Name of Prod. Zone	Type Prod. (Oil or Gas)	Method of Prod. (Flow or Art. Lift)	Prod. Medium (Tbg. or Csg.)
Upper Comp.			
Lower Comp.			

PRE-TEST SHUT-IN PRESSURE DATA

	Hour, date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)
Upper Compl.				
Lower Compl.				

FLOW TEST NO. 1

Commenced at (hour, date)* _____ Zone producing (Upper): _____

Time (hour, date)	Lapsed time since*	Pressure Upper Compl.	Pressure Lower Compl.	Prod. Zone Temp.	Remarks

Production rate during test
Oil: _____ BOPD based on _____ Bbls. in _____ Hrs. _____ Grav. _____ GOR _____
Gas: _____ MCFPD; Tested thru (Orifice or Meter): _____

MID-TEST SHUT-IN PRESSURE DATA

	Hour, date Shut-in	Length of time shut-in	SI press. psig	Stabilized? (Yes or No)
Upper Compl.				
Lower Compl.				

FLOW TEST NO. 2

Commenced at (hour, date)** _____ Zone producing (Lower): _____

Time (hour, date)	Lapsed time since **	Pressure Upper Compl.	Pressure Lower Compl.	Prod. Zone Temp.	Remarks

Production rate during test
Oil: 15 BOPD based on 15 Bbls. in 1 Hrs. 24 Grav. 42 GOR 10,000
Gas: 150 MCFPD; Tested thru (Orifice or Meter): 1 Hour

REMARKS: Unable temporarily flare in during flow period.

I hereby certify that the information herein contained is true and complete to the best of my knowledge.

Approved: 1-20 1961
New Mexico Oil Conservation Commission

By _____

Title _____

Operator Continental Oil Company

By FRED VAN MAIRE

Title District Engineer

Date January 18, 1965

JAN 20 1965
OIL CON. COM.
DIST. 3

Docket No. 21-65

DOCKET: EXAMINER HEARING - WEDNESDAY - JULY 28, 1965

9 A.M. - OIL CONSERVATION COMMISSION CONFERENCE ROOM, STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

The following cases will be heard before Daniel S. Nutter, Examiner, or Elvis A. Utz, Alternate Examiner:

CASE 3277: In the matter of the hearing called by the Oil Conservation Commission on its own motion to consider the creation of a new pool for Ellenburger production in Sections 4 and 5, Township 24 South, Range 38 East, Lea County, New Mexico, said pool to be designated the Stateline-Ellenburger Pool; further to consider the establishment of a procedure whereby allowables for wells in said pool may be assigned on an equitable basis with allowables assigned to wells in the same common source of supply in the State of Texas.

CASE 3278: Application of Standard Oil Company of Texas for special rules for the Stateline-Ellenburger Pool, Lea County, New Mexico. Applicant, in the above-styled cause, seeks the promulgation of special pool rules for the Stateline-Ellenburger Pool in Sections 4 and 5, Township 24 South, Range 38 East, Lea County, New Mexico, including a provision for 80-acre proration units.

CASE 3279: Application of Standard Oil Company of Texas for a non-standard unit and an unorthodox location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks the approval of a 688-acre non-standard gas proration unit comprising all of the partial Sections 34 and 35, Township 20½ South, Range 23 East, Indian Basin-Upper Pennsylvanian Gas Pool, Eddy County, New Mexico, said unit to be dedicated to a well to be drilled at an unorthodox location 990 feet from the South and East lines of said Section 34.

CASE 3280: Application of Bolack-Greer, Inc. for an unorthodox location, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks approval of an unorthodox oil well location 850 feet from the North line and 1030 feet from the East line of Section 16, Township 25 North, Range 1 West, Puerto Chiquito-Gallup Oil Pool, Rio Arriba County, New Mexico.

CASE 3281: Application of Samuel G. Dunn for a two-well proration unit and an unorthodox location, Rio Arriba County, New Mexico. Applicant, in the above-styled cause, seeks authority to drill and produce the second well on the 160-acre oil proration unit comprising the SW/4 of Section 26, Township 26 North, Range 1 East, Puerto Chiquito-Gallup Oil Pool, Rio Arriba County, New Mexico, the 160-acre allowable to be produced from either well in any proportion. Said second well would be drilled at an unorthodox location 1720 feet from the South line and 460 feet from the West line of said Section 26. (The SW/4 of Section 26 is currently dedicated to a well in Unit M of said section). In the alternative, applicant seeks the creation of two non-standard 80-acre proration units comprising the N/2 SW/4 and S/2 SW/4 of said Section 26 to be dedicated to the proposed well and the existing well, respectively.

CASE 3282: Application of Continental Oil Company for a special allowable, Lea County, New Mexico. Applicant, in the above-styled cause, seeks the assignment of a special allowable to wells on its Eaves "B" Lease in Section 31, Township 26 South, Range 37 East, Jalmat Pool, Lea County, New Mexico, which allowable would permit equalized per-acre withdrawal rates from applicant's wells (on 40-acre spacing) to the per-acre withdrawal rates from 20 acre wells located immediately south of said Eaves "B" Lease in the Scarborough Pool, Winkler County, Texas. In the alternative, applicant seeks the designation of a separate new pool for Yates production for said Section 31, and the establishment of a procedure whereby special pool allowables would be assigned to effect such equalized per-acre withdrawals.

CASE 3073 (Reopened):

In the matter of Case No. 3073 being reopened pursuant to the provisions of Order No. R-2758, which order, as amended by Orders Nos. R-2758-A and R-2758-B, established 160-acre oil well spacing and 320-acre gas well spacing for the Tocito Dome-Pennsylvanian "D" Oil Pool, San Juan County, New Mexico, for a period of one year. All interested parties may appear and show cause why said pool should not be developed on 40-acre oil well spacing and 160-acre gas well spacing, or such other spacing as may seem proper.

CASE 3112 (Reopened): Continued from the June 30th Examiner Hearing

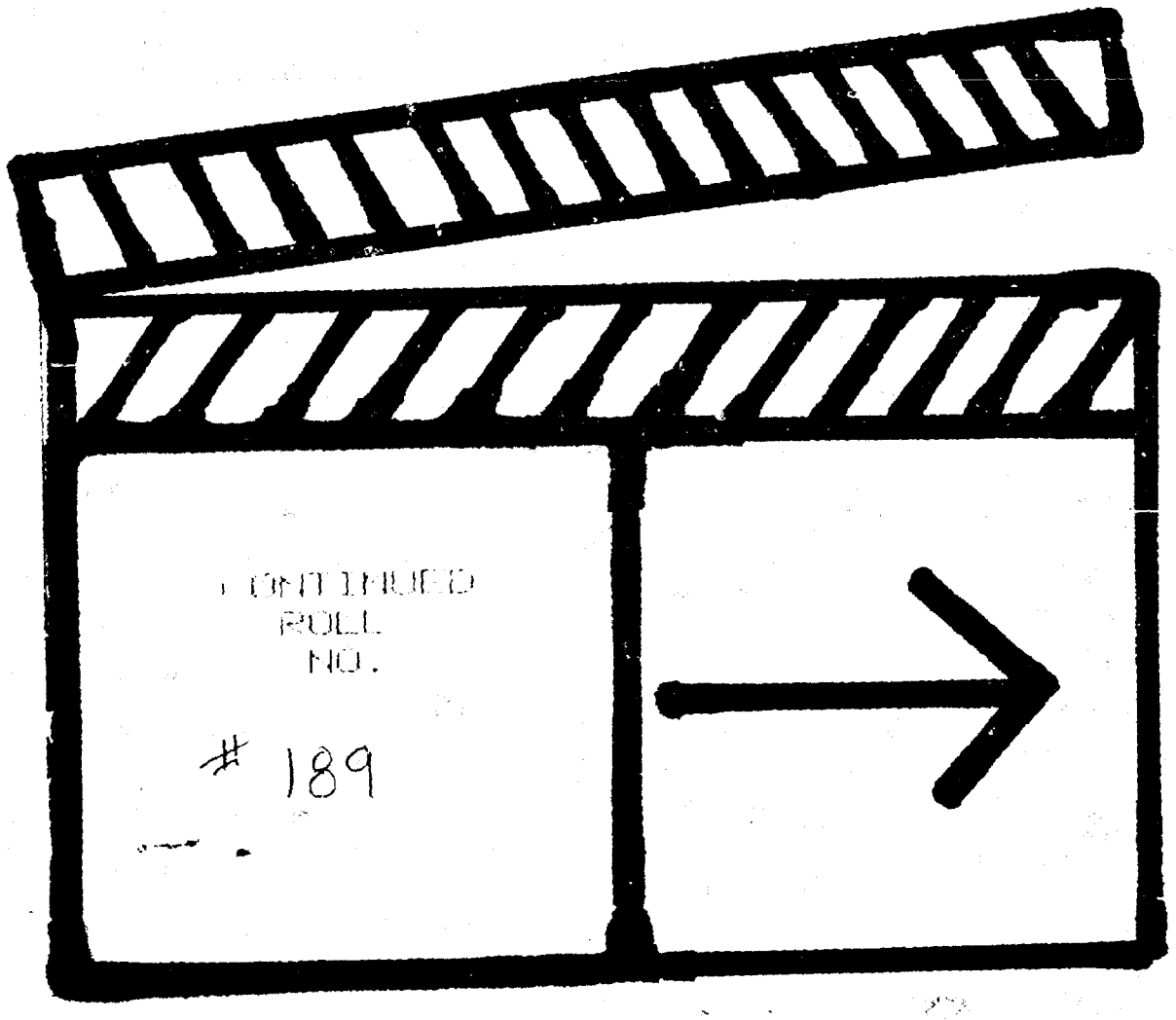
In the matter of Case 3112 being reopened pursuant to the provisions of Order No. R-2824, which order authorized Gallup-Dakota commingling in the wellbore by means of a dual-flow downhole choke assembly in its Jicarilla 28 Well No. 1 located in Unit J of Section 28, Township 25 North, Range 4 West, Rio Arriba County, New Mexico. All interested parties may appear and show cause why the authority granted under this order should not be terminated.

CASE 5122: Appli. of CONTINENTAL OIL CO. for downhole commingling, Rio Arriba County, New Mexico.

THIS IS A CONTINUED ROLL

SEE ROLL NUMBER: # 190





C.I. MICROGRAPHICS W.N.M.C.F.

P.O. DRAWER 250

GRANTS, NEW MEXICO 87020

MICROFILM RECORDS ADDITIONS

ROLL NUMBER #189

By virtue of their content and their relation to other microfilmed records on this roll, the following listed records are added to this roll as supplementary material due to a malfunction.

FIG. 6, 8 & 10 in Journal of Petroleum Technology Pamphlet

I hereby certify that the following microfilm images are true copies of the original records listed above.

Jaime R. Howell
CAMERA OPERATOR

11-16-87
DATE

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.

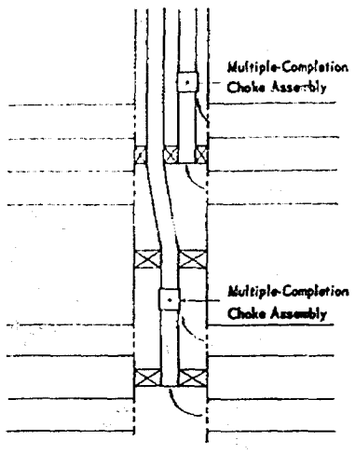


Fig. 5—Two-string quadruple completion.

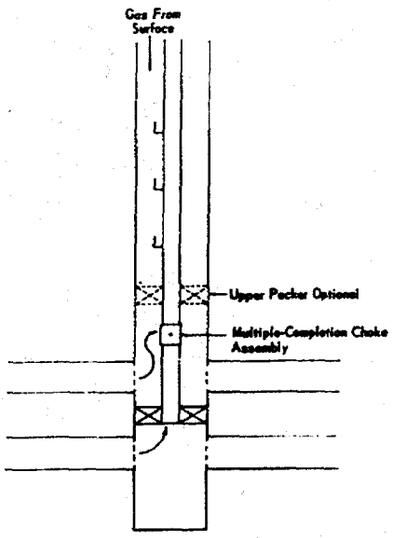


Fig. 6—Gas-lifting two zones with one string of flow valves.

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.

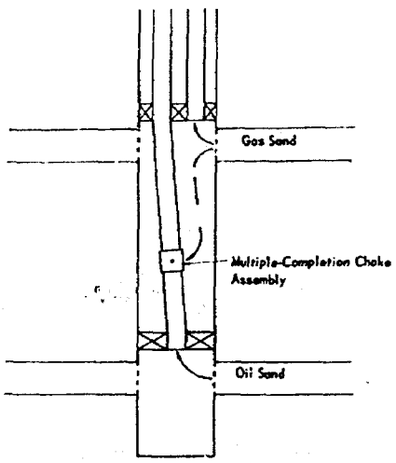


Fig. 7—High-pressure gas to sales line and lifting deep, low-pressure oil zone. Side-door choke is run in landing nipple until multiple-completion choke assembly is needed.

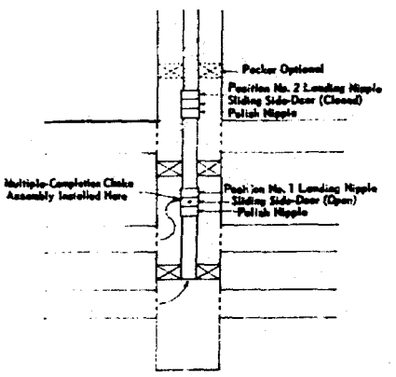


Fig. 8—Selective completion using multiple-completion choke assembly. Two of the zones are produced simultaneously. When either is depleted, it is replaced with the third zone.

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.

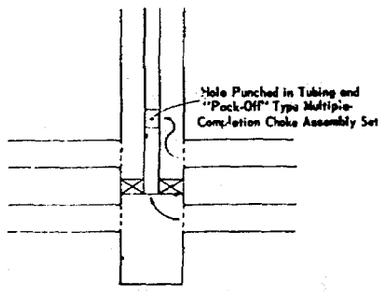


Fig. 9—Method of installing multiple-completion choke assembly in well not originally equipped with side-door choke landing nipple.

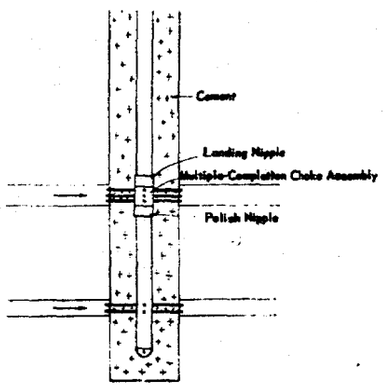


Fig. 10—One-string dual tubingless completion.