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

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?

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 each zone tested separately; and the well had an I. P. of 117 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 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?

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 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.

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 commingling 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 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.

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 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 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 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 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 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.

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 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?

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 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 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.

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 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 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

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?

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

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.

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.

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 [illegible] your check valve assembly?

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 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 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 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 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, 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 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?

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 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 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 pump them, 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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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.

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.

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 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?

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.

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.

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 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 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 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 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 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 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

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 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?

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 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 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.

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.

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 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 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 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 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 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 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 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 oould 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 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 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.

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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.

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.

........, Examiner
New Mexico Oil Conservation Commission