STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING)
CALLED BY THE OIL CONSERVATION)
DIVISION FOR THE PURPOSE OF)
CONSIDERING:) CASE NO. 11,212
)
APPLICATION OF CONOCO, INC.)

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

March 2nd, 1995

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Division on Thursday, March 2nd, 1995, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

March 2nd, 1995
Examiner Hearing
CASE NO. 11,212

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E X H I B I T S

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A P P E A R A N C E S

FOR THE DIVISION:

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FOR THE APPLICANT:

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By: W. THOMAS KELLAHIN

* * *

WHEREUPON, the following proceedings were had at 11:00 a.m.:

EXAMINER CATANACH: All right, we'll call the hearing back to order and call Case 11,212.

MR. RAND CARROLL: Application of Conoco, Inc., for downhole commingling and for an exception to the gas-oil ratio limitation factor established by Division Order Number R-8909, Lea County, New Mexico.

EXAMINER CATANACH: Are there appearances in this case?

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of the Applicant, and I have two witnesses to be sworn.

EXAMINER CATANACH: Any other appearances?

Will the two witnesses please stand and be sworn in?

(Thereupon, the witnesses were sworn.)

MR. KELLAHIN: Mr. Examiner, my two witnesses today, David Nelson is a petroleum geologist, Damian Barrett is a petroleum engineer.

Mr. Nelson and Mr. Barrett testified before you as a Hearing Examiner back in January of 1994 concerning this Conoco Warren Blinebry-Tubb waterflood project.

As a result of that hearing, you established the procedures for a second expansion area for the project. And I'm going to give you a copy of Exhibit 1 from that January hearing and a copy of the order that was issued by the Division based upon that case. The case is 10,897; the order issued from that case is Order Number R-10,068.

And I'm going to begin this morning with having Mr. Nelson give us a quick summary of what justified that order and what Conoco has done since, and then bring you into the issue that we're here to address this morning.

So with your permission, I'm going to give you a copy of Exhibit 1 that will -- from the prior case that will outline for you the well configuration, as well as a copy of the prior order.

DAVID E. NELSON,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Nelson, for the record would you please state your name and occupation?

A. My name is David Nelson. I'm a geological advisor employed with Conoco in Midland, Texas.

Q. On prior occasions, Mr. Nelson, have you testified and qualified as an expert before this agency in the field of petroleum geology?

A. Yes, I have.

Q. Your last technical presentation to this Division was when, sir?

A. We came in December of 1994, 1994, two months ago.

Q. All right. The presentation made to the Examiner back in January of 1994 with regards to the Warren Unit, was that a presentation you were involved in?

A. Yes, it was.

Q. Since then, have you continued to be involved in the geology with regards to what we've identified as the Warren Unit?

A. Yes, I have.

Q. And based upon that participation, do you have further geologic conclusions and opinions that are relevant to the Application today?

A. Yes.

MR. KELLAHIN: We tender Mr. Nelson as an expert petroleum geologist.

EXAMINER CATANACH: Mr. Nelson is so qualified.

Q. (By Mr. Kellahin) Mr. Nelson, let's start, sir, if you will, with the Exhibit 1 from the prior hearing that was conducted before the Examiner. It was in Case 10,897.

And before we get into the details, help us refresh our recollections about the various stages within the Warren Unit boundary.

A. The map which you have in front of you from that prior hearing was Exhibit 1, presented in that hearing, and it shows a map of the Warren Unit boundary, a thick bold line surrounding several sections.

At that time we were providing information about a proposed waterflood operation within the Warren Unit, focusing on the Blinebry and Tubb formations.

In 1991, Conoco came before the Commission seeking to expand the Blinebry waterflood from a pilot project that had been conducted several years earlier, and we call that the first expansion.

Q. How would that first expansion area be identified on the Exhibit 1 the Examiner is looking at?

A. That's right, on this exhibit the first expansion is shown as the Warren Blinebry-Tubb Oil and Gas Pool in the waterflood area, a label on that map, and that first expansion covered Sections 26 and 27 within Township 20 South and Range 38 East.

Q. Was the waterflood project conducted within the first expansion area, if you will?

A. Yes.

Q. And was that successful?

A. The -- May I ask, are you referring to the pilot?

Q. The pilot project area, if you will.

A. Yes, in the pilot project, only the Blinebry was flooded. This began several years ago, and it occurs in Sections 33 and 34, on the south side, and that could be characterized as a successful waterflood project.

And as a result of that success, we wanted to expand the operations in Sections 26 and 27, and we also wanted to include at that time the Tubb with the Blinebry.

Q. As a result of the January 20th, 1994, hearing in Case 10,897 and the Division's approval then of that accepted expansion, what did that order provide you the opportunity to do?

A. Well, the order which was issued in 1994 allowed Conoco to expand for a second time the Blinebry and Tubb operations into Section 28 and 29. We have since drilled several wells in Section 28 to complete the development of primary production within Section 28.

I might add that in addition to the Blinebry-Tubb, we have found that the Drinkard is also a productive reservoir within Section 28.

Q. Before you initiated the additional activity that was authorized by the Order from January of 1994, if you'll look at this Exhibit 1, we're still -- have before us, describe for us in Section 28 why no further activity had been undertaken up to that point.

A. At that time there were separate pool rules established for the Blinebry, for the Tubb and for the Drinkard within Section 28, and the characteristics of the reservoir and the pool rules under which we were operating limited the development within Section 28.

Q. Give us a quick characterization of the rule differences between the Blinebry and the Tubb that made it so difficult, then, to have previously developed those two formations.

A. Well, the Tubb pool rules were different from the Blinebry in that the Tubb had, for example, a gas well which would be -- determine whether -- on the basis of the oil gravity. Above 45 degrees gravity in the Tubb would specify that well is a gas well rather than an oil well. It was not based on GOR. And we would have to dedicate 160 acres to any gas well within the Tubb.

The Blinebry was operating under a different set of pool rules, and so we just could not develop this reservoir for the same formations in the same manner.

Q. What did this Examiner do for you in the prior order that resolved that operational limitation, if you will, that discouraged further development?

A. What we presented at that time was a plan for waterflood operations, and those waterflood operations would be conducted in both the Blinebry and in the Tubb.

We asked that we change the designation of the

Blinebry and the Tubb pools by contracting those pools and assigning them to a combined Blinebry-Tubb pool, which was then designated the Warren Blinebry-Tubb Oil and Gas Pool as a result of Order R-10,068.

Q. As a result of those changes, then, let's look at the Exhibit 1 for today's hearing and have you help us understand what additional activity has taken place.

A. Well, as a result of obtaining the Order R-10,068, Conoco went ahead and did work associated with the expansion -- a second expansion of the Warren Blinebry-Tubb Pool.

We drilled several other wells within Section 28, and we completed the development, or planned to complete the development within Section 28 on a 40-acre spacing.

Q. How many additional wells were drilled?

A. Ten additional wells have been drilled.

Q. Okay.

A. Four other wells are planned in the section.

We also have found that the Drinkard is productive within that section, and the Drinkard is dually completed with the Blinebry-Tubb in some of the wells within Section 28.

Q. Had the Division not authorized the second expansion into the Blinebry and Tubb activity, then you would not have realized this new potential in the Drinkard?

A. That's right, because further drilling would not have been conducted in the section.

Q. When we look in Section 28 now and look at Exhibit 1, which is the Exhibit 1 for today's hearing, it's got some color codes.

A. Yes, sir.

Q. Let me have you take that exhibit, and let's describe for the Examiner the color codes.

A. Okay. Exhibit 1 for this hearing focuses on the Warren Unit again. The Warren Unit boundaries are outlined in bold blue lines.

The color coding within Section 28 and parts of Section 27 show an area in orange where we are proposing that we downhole commingle the Blinebry-Tubb with the Drinkard production.

The area in yellow is an area where the wells are dually completed. And we propose to continue to dually complete wells in the Blinebry, Tubb and Drinkard in that area.

MR. KELLAHIN: Mr. Examiner, in our prehearing statement we've taken the opportunity to specifically identify and describe and then categorize the group of wells shown for which we would like some relief, and they fall into three groups.

There is going to be a group of six wells that are either shut in or temporarily abandoned in the Drinkard. We would seek approval to commingle production in those wellbores so that the Blinebry, Tubb and Drinkard intervals are all commingled.

In addition, there will be a group of four wells on the prehearing statement that are currently dual-completed and still producing, and we're seeking permission, then, on those four wells as identified to remove the dual configuration and to further produce them in the future as downhole-commingled wells.

And then there will be four new wells, not yet drilled, for which we seek to drill and produce them initially as commingled wells.

Q. (By Mr. Kellahin) Mr. Nelson, when we look at the results of the dual-completion effort, what are you seeking to do with those wells that are in the area identified by the gold shading?

A. Okay --

Q. Tell me what that means.

A. -- yeah, the wells that are in the gold or the yellow shading -- or the orange shading -- are wells which at this time are subeconomic for commercial -- for production from the Drinkard when operated as dual wellbores.

Q. Within the yellow area those wells are what, sir?

A. Within the yellow area, those wells are presently economic to produce as dual wellbores with the Drinkard on one side and the Blinebry-Tubb on the other.

Q. Is there a geologic explanation as to why we are seeing wells in the Drinkard in this outer circle, if you will, that are subeconomic in the Drinkard?

A. Yes, there's a geological explanation as to why these wells are subeconomic.

Q. Okay. Let's turn to that geologic explanation. If you'll direct your attention to what is marked Exhibit Number 2, identify that exhibit for the Examiner.

A. Okay, Exhibit Number 2 is a Drinkard structure map. It focuses on the Warren unit again, and this is a structure map drawn on the top of the Drinkard formation. The scale of the map is one inch to 2000 feet. The structural contours are drawn at a contour interval of 25 feet.

It clearly shows a four-way closed anticline that's contained entirely within the Warren Unit, and that anticline encloses the Drinkard Pool, or the Warren-Drinkard Pool.

Q. On Exhibit 2, you have a dotted red line that represents what, sir?

A. The dotted red line is cross-section A to A'. It trends northwest to southeast across the structure, and --

Q. If you'll keep Exhibit 2 in front of you, and let's turn, then, to that cross-section and have you unfold that cross-section which is marked Exhibit 3.

Before we discuss your conclusions, I would like to have you take some care in explaining to us where we're going to find the base of the Blinebry, then the top of the Tubb, the base of the Tubb, and then the top of the Drinkard, so we get these formations in the correct sequence on one of these logs.

A. Okay, this cross-section shows a part of the Blinebry formation. It shows the Tubb formation, the Drinkard and a part of the Abo formation.

Q. Let's look, if you will, at the first well on the left. It's the Warren Unit 116 well. Starting at the top of the log, take us down and show us what the meaning is every time you change a color.

A. Sure. The Blinebry formation has been subdivided by us into four or five different porosity intervals, and we refer to these porosity intervals 1 through 5, starting at the top, and I am showing you just the lower portions of these porosity intervals in the Blinebry, and they are labeled on this cross-section as B3, B4, B5.

The intervals are colored in green, and the white bands on the cross-section between those intervals are the nonporous intervals, the tight intervals separating the porosity intervals of the Blinebry.

Q. When we get down to the base of the lowest green interval and the corresponding top of the purple interval, there's an identification off to the left of the log that says "Tubb Marker". What are we seeing at that point?

A. The Tubb marker shows the contact between the overlying Blinebry formation and the underlying Tubb formation. The Tubb marker is a geologically mappable marker across the Lea County area that designates the top of the Tubb formation.

Q. If you go down to the base, then, of the purple area, what's the next marker point identified on the log?

A. That's the top of the Drinkard formation, and the Drinkard formation is not color-highlighted across the section. Between the Drinkard and the top of the Abo you'll see I've not placed color, at least in the Warren Unit 116.

Q. All right, just below, if you continue on the log, there's going to be a line that's -- a black line running horizontal across the entire length of the cross-section. What does that represent?

A. That represents the structural datum for this cross-section. That is drawn at an elevation of minus 3250 feet subsea vertical depth, and it represents an established oil-water contact within the Drinkard reservoir. We'll also refer to that as a water transition zone.

Q. If you go with me to the next log to the right, it's the Warren Unit 94 well?

A. Yes, sir.

Q. Go down to the datum point, which is the base of the lowest green-shaded area, and what does that show in that well?

A. Well, now, in the Warren Unit 94 I'm introducing another green pattern to the cross section, and I'm beginning to show you the development of the main pay within the Drinkard formation.

To help you see that, I've shown log curves on the cross-section. The log curves which have yellow highlighting to them show porosity development. The main pay of the Drinkard is where we have porosity that exceeds six percent, and that main Drinkard pay, where it occurs above the datum of 3250 subsea, is our hydrocarbon reservoir.

Q. Below the datum point, that porosity indication on this log is in the water portion or at least in that portion of the reservoir that has significant water cut to it?

A. That's correct. Below 3250 subsea vertical depth, we enter the water transition zone, and we have done tests within the reservoir where we have isolated perforations below that zone, and we get high water cuts.

Q. When we look, later on, to see the wells for which you're seeking approval for downhole commingling, will that group of wells include the Warren Unit 94 well that we're looking at now?

A. That's right.

Q. And why geologically, then, would the 94 well fall within the group of wells for which downhole commingling is justified?

A. The Warren Unit 94 well is one which is beginning to drop off the structure, and we move into a thinner development of the pay column, such that our oil rates, oil and gas rates, are much lower as we move offstructure, and that net pay development of the Drinkard is thinner.

Q. Okay, let's continue to the right, then, and contrast the 94 well with the 108, which is a well in the inner portion of the structural high and is to continue to be produced as a dually completed well.

A. That's correct, the Warren Unit 108, we move upstructure onto the anticline. It's located near the culmination of the anticline. The pay column is well developed at that location.

These wells can be dually completed with the Blinebry and Tubb, and we can conduct those operations economically.

I would add that the 95, adjacent to it, is similar in that aspect.

Q. All right. Now, let's continue after the 95 to the 97 and look at a well, 97 --

A. Okay.

Q. -- which falls back into the category of a group of wells for which you're seeking to obtain downhole commingling approval.

A. The Warren Unit 97 is now moving off onto the southeast flank of the four-way closed anticline. The development of the main pay in the Drinkard is now thinner, and the well tests which I've written below the Warren Unit 97 well show that we had low oil rates and high water cuts. It shows initial production, pumping six barrels of oil a day, 23 MCF of gas, and 194 barrels of water.

You can see also that we have some of our perforations into that water transition in the Warren Unit 97, and that may account for some of the high water.

The main point is that as we move off the structure, that main pay development is thinner and doesn't support the economic production when it's dually completed with the Blinebry and Tubb.

And it's important to emphasize that the Drinkard is a reservoir that's of less importance to the total reserve picture on the lease than the Blinebry and Tubb, which we have a long-term plan for waterflood operations.

Q. When you look at the log porosity on the 97 well, the highest point of porosity values in the Drinkard are falling below that oil transition -- that oil-water transition interval, are they not?

A. That's right.

Q. Let me have you turn to the next display, Exhibit 4, and have you put all this together for us.

A. Exhibit 4 combines the map which I presented to you as Exhibit 1, showing the areas that we would like to commingle production, along with the structure contours from Exhibit 2, and the trend of the cross-section A-A', which is Exhibit 3.

You can now see that the wells which lie in the orange-colored area are in structurally low positions where the pay is thin, it's not as well developed as it is higher on the structure.

The area that is shown as yellow highlighting is the crest of the anticline, and those wells have a sufficient pay column to support economic production as dual-completed wells.

Structure is not entirely the story; there is some variation in the quality of pay in terms of its porosity and its permeability. But generally there's a good correlation between structure and the pay development from this reservoir.

Q. Let's look at the timing of how you recover the available hydrocarbons out of the Drinkard in relation to the sequencing of how you're exploiting the Blinebry-Tubb, which is your principal hydrocarbon-recovery reservoir in the unit area.

A. Well, the Blinebry-Tubb is our principal reservoir. It is presently under primary production with a long-term plan for waterflood operations in that pool.

Right now, these wells are being drilled primarily to access the Blinebry and Tubb, to recover the primary production from that, and then moved into the secondary recovery in the future. We are presently estimating that that conversion will begin in about the year 2007.

So between this point in time and the point in time in the future that we convert to waterflood operations, we have the opportunity to recover the Drinkard reserves.

Q. Why do you lose the opportunity to recover the Drinkard reserves after the year 2007?

A. Well, at that time the wells will be converted to inject -- on an injector and producer basis. We'll lose the opportunity to recover the reserves in those wells that we convert.

Also, there will be continual production from the crestal area, and that possibly will draw down the reservoir pressure.

So we'll leave a significant amount of reserves behind in these fringe wells if we do not at this time commingle the production with the Blinebry and the Tubb.

Q. What's the forecasted or projected total life of the waterflood operation in the Blinebry and Tubb?

A. Well, I am not familiar with how far into the future that will go, but if I could defer that question to Mr. Barrett, I think he will best answer that.

Q. Summarize for us, then, geologically why we're seeing this group of -- I guess it's ten existing wells, and the locations for the four new wells --

A. Uh-huh.

Q. -- within this circle, to not be able to sustain themselves as dually completed wells.

A. Okay. Well, the ten existing wells -- Would you like me to identify those on the map for the Examiner?

Q. Yes, sir, I think that would be helpful.

A. The ten existing wells, if I were to start in Unit A of Section 28, Warren Unit 98; and moving to Unit B, Warren Unit 10, Warren Unit 114; move to Unit E, Warren Unit 115, Warren Unit 94; skipping down to unit -- O, is it? in Warren Unit 113.

Also there -- in Section 27, Warren Unit 9 is in Unit E; and Warren Unit 26, I believe that's Unit M; in Section 34, Unit D is Warren Unit 97; and Section 33, Unit A, Warren Unit 99.

I believe that's the ten wells which lie in the fringe area. Those are the existing wells. Four of these wells are presently dual completions.

Q. If it doesn't have a black line through the well symbol, then it is still a current producer?

A. That's correct.

Q. All right. Identify for us, then, the four locations.

A. Okay, the four locations that are presently in a dual configuration are the Warren Unit 114 in Unit C of Section 28, Warren Unit 94, Warren Unit 115 -- that's in Unit E -- and Warren Unit 113 in Unit O.

Now, those wells are presently dually completed, and our practice had been to try and dual-complete these with the Blinebry and Tubb, but we have learned from our testing throughout the year that these are not going to be economic in the Drinkard.

MR. KELLAHIN: Mr. Examiner, that concludes my examination of Mr. Nelson.

We move the introduction of his Exhibits 1 through 4.

EXAMINER CATANACH: Exhibits 1 through 4 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Let me see if I get this straight, Mr. Nelson. Ten wells in the orange- or gold-colored area, existing wells, four of those are currently dually completed, the remaining six are currently just Blinebry-Tubb producers?

A. Yeah, they are at least shut in, in the Drinkard.

Q. Were they dual completions?

A. We attempted some dual completions in some of those wells at one time and then had to plug those out.

Mr. Barrett will have an exhibit that shows when those wells were shut -- were plugged out of the Drinkard, or shut in temporarily.

Q. With this Application you're seeking approval to downhole commingle all ten of those wells in the Blinebry, Tubb and Drinkard?

MR. KELLAHIN: Plus approval to drill four new ones.

EXAMINER CATANACH: I'm getting to that.

MR. KELLAHIN: Right.

Q. (By Examiner Catanach) Where are your four new wells going to be?

A. Okay, the four new wells, I have open circles on those wells. The four new wells are Warren Unit 116 in Letter Unit D.

Q. D of what section?

A. Section 28.

Q. Okay.

A. Warren Unit 117.

Q. And where is that it at?

A. Unit L, Section 28.

Q. Okay.

A. Warren Unit 118 unit M.

Q. Got it.

A. And Warren Unit 119, Unit N.

Q. What is that one in Unit D? Is that 113?

A. That is 116.

Q. 116. Okay, so that's basically it. You're looking at 14 wells.

The area within -- The area that's colored yellow, those are current dual completions; you're not seeking any kind of relief in that area?

A. That's right.

Q. Okay. Within Section 27, your Warren Units 9 and 26, is that area currently under waterflood operation?

A. Yes, that area is part of our first expansion, and that is under waterflood.

Q. And you want to -- You're seeking approval to commingle Drinkard with the waterflooded Blinebry and Tubb formations?

A. Yes, in the two wells, in Warren Unit 9 and in Warren Unit 26, in that section, 27.

Q. Does that same hold true for the wells in Sections 33 and 34?

A. Yes, it does.

Q. Within the colored area on your map, the yellow and the gold, that's going to be the only area that the Drinkard is going to be developed in this unit?

A. Within the colored area, the gold-colored area, that is the present area that we at this time envision developing the Drinkard.

We -- You know, we've learned that as you move offstructure, the Drinkard becomes a poor reservoir. That's information we probably did not know at the time of the first hearing, at the hearing that we had in January, 1994. And at that time we were addressing just the Blinebry and Tubb, so the Drinkard was not part of the plan at that time.

Q. Okay. Now, within Section 28, we're still talking about -- Are the Blinebry and Tubb still separated in that section?

A. No, they have been combined into one pool, and that was the effect of the hearing and the order coming from the hearing of January, 1994.

Q. Okay. So the Warren Blinebry-Tubb Pool does extend into Section 28?

A. Yes.

Q. Okay, and it also covers 33, 34 and 27?

A. That's right.

Q. Okay. My understanding that this -- this is still -- in Section 28, this is all under primary production and will be until approximately the year 2007?

A. That's correct. The year 2007 is an estimate which Mr. Barrett will provide some testimony related to that projection.

Q. Okay. Does this also -- this area of primary development, this also includes Sections 21 and 20 and 29? Is that kind of one and the same?

A. As you move into Section 27 you move off to the north end of the structure, and it goes into a deep structural low.

There are wells in Section 21, in the Blinebry and Tubb, but not in the Drinkard.

And there are wells also in Section 20 and in 29, producing from the Blinebry and Tubb.

Q. Were all of these wells kind of drilled at the same time, the wells in 28, 29 and 20?

A. There's been a phased approach to drilling in this area, so they've not all been drilled at the same time.

EXAMINER CATANACH: I think I have nothing further at this time.

MR. KELLAHIN: Mr. Nelson may be excused?

Then we'll call our reservoir engineer, Damian Barrett. Mr. Barrett spells his last name with two r's and two t's.

<u>DAMIAN G. BARRETT</u>,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Barrett, for the record would you please state your name and occupation?

A. My name is Damian Barrett. I'm a reservoir engineer with Conoco.

Q. Mr. Barrett, on prior occasions have you testified in that capacity before this Division and been qualified as an expert in that area?

A. Yes, I have.

Q. Have you continued with your reservoir engineering duties concerning the Warren Unit?

A. Yes, I have.

Q. And based upon those duties, you now have opinions and conclusions about how to optimize the remaining recoverable production out of the Drinkard pool within the area described in this Application?

A. Yes, I do.

MR. KELLAHIN: We tender Mr. Barrett as an expert reservoir engineer.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Before we talk about the specifics, let me have you help us identify the issues.

From the engineering aspect, are you familiar with the Division's administrative rules for downhole commingling?

A. Yes, I am.

Q. Identify for us the issues within that administrative procedures that preclude this Application from being processed administratively.

A. Okay, this -- For this depth bracket allowable that we're talking here, the downhole commingling rules are 40 barrels a day of oil, the lower of the two pools' GOR, and 80 barrels of water per day. And right now --

Q. When we look at the commingled oil production, are there combinations of commingled production that would exceed 40 barrels a day?

A. Yes, there are.

Q. All right, and you've addressed that issue in looking at the engineering aspects?

A. Yes, I have.

Q. When we look at the water volume, your maximum water volume is 80 barrels of water a day?

A. Correct.

Q. And you have perhaps one example that exceeds that?

A. Correct.

Q. And in terms of a gas-oil ratio, your maximum gas-oil ratio is 8000 to 1?

A. For the Drinkard Pool, that's right.

Q. For the Drinkard, and that would translate and be the limit on the commingled stream unless the Examiner waives that limit?

A. That's correct.

Q. All right. Having examined all three of those issues, do you have any engineering concerns about accepting each of these wells from any of those three limits?

A. No, I don't.

Q. In addition, the fourth one is that while you're in a unit area, you will have federal unit participating areas that at least conceptually may have different percentages or interests that would preclude this from being commingled because of different ownership?

A. That's correct.

Q. All right. As part of the presentation today, have you gone through the effort of providing the Examiner with all the specific details on completion histories, production curves, proposed allocation formulas, the C-116s for all these wells?

A. Yes, I have.

Q. Let's look, then, at Exhibit Number 5.

A. Okay.

Q. When we look at Exhibit 5, help us understand how you have organized the information.

A. All right, Exhibit 5 is current productivity tests from the separate Drinkard formation, as well as the Blinebry-Tubb formation. Those are highlighted in green at the top, with Drinkard being on the left-hand side, Blinebry-Tubb being on the right-hand side.

On the far left the first column is the well number, all these wells that we are discussing about downhole commingling.

The next column is oil in barrels of oil per day.

The next column, gas in MCF per day.

The next, GOR.

The next, water in barrels of water per day.

And then for the Drinkard alone we have shut-in dates for the six wells that have been abandoned because of their uneconomic viability in the Drinkard as a dual.

Then moving -- continuing to move right, the next column is oil for the Blinebry-Tubb in barrels of oil per day, gas in MCF per day, GOR and water in barrels of water per day.

Q. When we divide your exhibit and look only at the Blinebry-Tubb, we are then looking at production that is continuing to be economic production?

A. That's correct.

Q. In terms of commingling, then, the portion of the commingling Application that deals with the uneconomic reservoir is the Drinkard side?

A. That's correct.

A. Is there anything that you can do from an operational aspect to add additional productivity to any of the wells within the Drinkard column?

A. We have done whatever we could so far.

Q. So when we look at the various individual well test rates, we're looking at production on a daily basis?

A. Correct.

Q. And this represents the capacity of these wells to produce hydrocarbons out of the Drinkard?

A. That's correct.

Q. On the Examiner's display, there are some corrections made with a pasteover?

A. Correct.

Q. Why was the change made?

A. The change was made because these wells that we currently have on line in the Drinkard as a dual are steadily dropping. And we had two wells in particular, the 113 and 115. These are our newer wells, they've been on line just a short period of time, and their decline is a little steeper than the other wells, and therefore their rate has dropped --

Q. All right.

A. -- since this was reported.

Q. Well 113 and Well 115, those reported rates represent what point in time? Is that a February, 1995, date?

A. One is January. The 113 is January, and the 115 is February.

Q. All right. For those wells that now have a shut-in date, what does that represent?

A. That shut-in date on those wells is when we had them in a dual situation before, but at that point in time -- and there's a variety of dates there -- it was no longer economic to produce that well at that dual rate because of the operational costs that were incurred.

Q. So the production levels for the shut-in wells correspond to the shut-in date?

A. That's correct.

Q. And if there is not a shut-in date, that test information is of what period?

A. January of 1995.

Q. Okay. Based upon your studies of the Drinkard reservoir, what kind of reservoir are we dealing with?

A. We're dealing with a solution gas drive reservoir, much the same as the Blinebry-Tubb.

Q. Do you see any evidence or indication that you can improve total hydrocarbon withdrawals from the Drinkard by reducing the rate?

A. Restate that for me.

Q. Yes, sir. My question is whether the Drinkard is rate-sensitive?

A. No, it's not.

Q. So if we reduce the rate of withdrawal to keep within a gas-oil ratio, whatever that number is, it's not going to add total reservoir recovery from that pool?

A. No, it's not.

Q. All right. Do you concur with Mr. Nelson's timing argument about now's the time to get the remaining Drinkard, because if we don't do it now, by the year 2007 we've lost the chance?

A. That's correct.

Q. And you've quantified that for us later on, have you not?

A. Yes, I have.

Q. When we look at Exhibit Number 5, are each and every one of these wells uneconomic to continue as dual wells?

A. That's correct.

Q. All right, sir. Let's turn now to Exhibit Number 6. Identify that display for us.

A. This display is economics run on just the Drinkard wells, with the different configurations that we currently have, or would move to.

Under the first situation with "Dual" written there, we have -- I used a rate of six barrels of oil per day, 240 MCF a day. It gives us a net present value, which is negative, of $13,000 and a zero-percent rate of return. So it's clear that that is not economic for us to continue with a well like that.

Then we move to the next one, downhole commingling a new well. This is again at a rate of six barrels of oil per day, 240 MCF a day. This is the worst-case downhole commingling rate that we would have, and it is a positive net present value of $51,000 and a 90-percent rate of return. So it is economic for us to downhole commingle even the worst Drinkard production.

Then the next one is shut-in well, and by that I'm meaning shut-in, bringing it back on as a downhole-commingle candidate. Its rate, its, again, worst-case rate of six barrels of oil per day and 28 MCF a day gives us a positive net present value of $15,000 and an 86 percent rate of return.

Q. When we look at the economics, what capital cost are you attributing to the profitability under this example?

A. For the dual well, the capital cost, which primarily involves just additional equipment, is $236,000.

Q. Describe for us the kind of equipment involved, then, between the dual and the downhole commingling.

A. Right. With the dual you need an extra pumping unit, you need a vent string for the gas, you need extra string of tubing, you need an extra string of rods, you need an extra pump, an extra flow line and a different wellhead. We also need bigger casing. And then there's labor associated with all that as well.

Q. In addition to those capital costs, what on an annual basis are the operating costs in excess of what you would have to operate a downhole-commingled well?

A. The extra operating costs are approximately $40,000 a year. A single downhole commingle -- or a single-well or a downhole-commingle well is basically $5000 a year.

The dual well is $45,000 a year, an incremental of $40,000 a year, and that's because of all the operational problems we have with communication problems between the packers, having to pull both wells, extra workover time and associated items there.

Q. Let's look at your best-case economics and go back to Exhibit 5 and look at the varying rates of remaining productivity for your wells on the Drinkard side of the production.

Do each and every one of the proposed commingled wells fall below the point at which they are continuing to be profitable as dually completed wells?

A. Yes, they do.

Q. You've got two variables: You've got an oil and a gas variable. But can you give us a sort of a benchmark to say, once I get my oil and gas rates below a certain benchmark, then it is no longer profitable for us to continue to produce it as a dual well?

A. Yes, I can. Basically break-even economics, we're at 22 barrels of oil per day and 123 MCF a day. That basically gave us almost zero net present value, and a rate of return of nine percent, which is not economic to do. That's a break-even point.

And with that, the oil is valued much higher than the gas, and so therefore there's nothing that's even close to that 22 barrels of oil per day.

Q. Let's turn to another issue. If you'll turn to Exhibit 7, have you been able to quantify the additional reserves that you would not otherwise recover in the absence of the downhole commingling?

A. Yes, I have.

Q. And that's what we're seeing on Exhibit 7?

A. That's correct.

Q. Identify the display for us and describe for us what you've done.

A. Okay, these are additional reserves beyond the economic limit through downhole commingling.

Starting with the Drinkard on the left-hand side -- I gave the Blinebry-Tubb on the right-hand side -- these are -- on the Drinkard reserves I've got the well number on the far left, oil in MBO, gas in MMCF.

With these, I chose a point best in time that would allow us to recover the Drinkard reserves, plus that which does not hamper the start date of our waterflood, and that -- my best estimate right now is the year 2007.

With this, I ran decline curves on both oil and gas for each well, here, and that's where these reserves came from.

Q. What's your cumulative total of additional reserves added to your recovery, if this Application is approved?

A. If this is approved, we will add an additional 231 MBO and 2.8 BCF of gas, just from the Drinkard alone.

Q. And in the absence of approval, the Drinkard will have to be abandoned, and these are recoverable reserves that would not be produced now or in the future?

A. That's correct.

Q. Okay. Let's go to Exhibit Number 8, if you will, and let's address another topic.

One of the issues for the Examiner to authorize your request to exceed the gas-oil ratio limitation that's built into the Drinkard rule of 8000 to 1, and you described for me earlier your conclusion that the Drinkard was a solution gas drive reservoir.

What is the purpose of Exhibit Number 8?

A. Exhibit Number 8 is an offsetting well, Britt B 10. It's in the Tubb formation. And what this is -- Overall, this is an example of a typical solution gas drive reservoir.

Q. All right, we're seeing this pulled out of the Monument-Tubb?

A. Correct.

Q. And how far away is that?

A. That's about two miles to the west.

Q. What is the relevance of looking at the characteristics of production out of the Britt B 10 well from a different pool?

A. The relevance here is, there was a lot of data taken on this Britt B 10 Number well that helps prove the solution gas drive dropping below the bubble point and how that affects the reservoir.

It's a -- There was a lot of data taken here that we have a record of, that we can show this case, and it's similar to ours.

Q. All right. If your challenge as a reservoir engineer, then, is to find a blueprint of what a classic solution gas drive reservoir well would do, is this it?

A. This is it.

Q. Describe for us without a great deal of detail the kinds of things that caused you to believe that this was significant data resulting in the classic signature of a solution gas drive reservoir.

A. Okay. In the top portion of the graph, you've got oil rate in black, gas rate in red. Those are daily rates of barrels and MCF.

The next one down, you've got a red curve showing gas-oil ratio.

And then at the bottom you have bottomhole pressure. With this, we actually took pressures at varying points in time right after this well was discovered, and those pressures went up and to the point where we also had PVT data that gave a bubble-point pressure of 2370 p.s.i.

The bottomhole pressures were taken up to that point. At that point where the arrow is, you see the GOR increase dramatically here. That's where we dropped the reservoir pressure to that point. At that time the GOR increased significantly there, giving testimony to the solution gas drive reservoir.

Q. As a reservoir engineer, can you conclude, then, in a solution gas drive reservoir that we can withdraw production from that reservoir without regard to the gas-oil ratio?

A. Yes, I can.

Q. All right. Show us, then, how you've made this comparison to what you've seen from the performance of a well within the Application area.

A. Okay. Moving to Exhibit Number 9, this is the Warren Unit Drinkard production, and it's again very similar, but I don't have the pressure data here to add to this exhibit.

But we are showing the -- There are three wells included in here that were the discovery wells. They start out in the early Fifties. The solution gas, the GOR, was very low at that point in time.

Once we reached the bubble-point pressure, the GOR took off, increasing just like it did in our Britt B 10 example.

Q. Do you see any indication of a gas-cap problem?

A. No, I don't.

Q. Any need to curtail gas withdrawals from this reservoir?

A. No.

Q. Okay. Turn now to Exhibit 10. Exhibit 10 again has some corrections due to the updated production data from wells 113 and 115?

A. That's correct.

Q. All right. Describe for us what's the purpose of Exhibit 10.

A. The purpose of Exhibit 10 is to just show the combined tests that we expect once we -- the current productivity tests that's just added the Blinebry Tubb and the Drinkard flow streams together.

Again, the well on the left, barrels of oil per day. Next, gas in MCF per day, barrels of water per day, and then the GOR.

Q. What's your maximum depth bracket oil allowable for this production?

A. In separate pools, the maximum -- well, separate just for the Drinkard is 142 barrels a day with an 8000

GOR.

For the Blinebry-Tubb at this point, since we're in the waterflood area, we have unlimited allowable.

Q. As we look at the spreadsheet and find the oil column, under the administrative commingling rules you'd be limited to a combined oil rate not in excess of 40 barrels of oil a day?

A. That's correct.

Q. And you're going to have a few of these wells that exceed that?

A. That's correct.

Q. Any reason to limit the approval to only those wells that don't exceed the 40-barrel-of-oil-a-day limit?

A. I don't see any reason for that.

Q. The gas column here, you've got perhaps one well that would exceed the limit of the 8000-to-1 GOR?

A. That's -- Currently, yes.

Q. And that would be the 114?

A. Correct.

Q. Any problem with letting this well exceed that GOR?

A. Not at all.

Q. Then the water column, the water limit is 80 barrels of water a day?

A. Correct.

Q. And you've got one well that exceeds that?

A. That's correct.

Q. Is there a water component attached to the 97 well that needs to be worried about?

A. That would be addressed if we get this -- whenever we go back in, even though that well is shut in, when we go back in on that well, we will attempt to squeeze off that water production.

Q. Okay. Let's have you identify for us Exhibit Number 11.

A. Exhibit Number 11 is basically just the reservoir pressures from a common datum of minus 2850 subsea depth, for the two reservoirs in question, and this is just to show that there's not a problem with one being 50 percent higher than the other.

Q. All right. You've stayed within that guideline of the commingling rule?

A. That's correct.

Q. All right, sir. Exhibit Number 12, identify and describe that.

A. This again is just the -- what the Application asks for on the gravity, mixing of the oil to assure that there is no value lost from the mixing of two gravities. These gravities are very similar anyway, and with the calculations here there's virtually no change.

Q. All right, sir. Turn now to Exhibit 13. Identify and describe that.
A. This is a water analysis compatibility test for the Blinebry-Tubb water on the left and the Drinkard water on the right. And again, the waters are fairly similar.
And then down below there's a mixed water analysis telling you, you know, different proportions that you'd mixed these waters, and with that there is not any significant problems with mixing these waters.
Q. Do you know, Mr. Barrett, whether or not we're dealing with a project area that's totally within a federal unit?
A. Yes.
Q. Have you or other representatives of Conoco informed the Bureau of Land Management about this proposed commingling Application?
A. Yes, we have.
Q. And what if any information or correspondence have you received from the Bureau of Land Management in response to your Application?
A. We've received the letter which is labeled Exhibit Number 14, showing that they have -- the BLM has no objection to our proposal to downhole commingle these wells.
Q. All right, sir. If the Examiner agrees with your

engineering conclusions about the feasibility and the appropriateness of commingling, do you have an allocation formula --

A. Yes, I do.

Q. -- to propose?

A. Yes, I do.

Q. Is the allocation formula you're about to propose consistent for all the wells in terms of method?

A. Yes, it is.

Q. Let's look at Exhibit 15 through 24 and have you tell me what those represent.

A. Okay. The 15 Exhibit would be an example that all of them are based on. This is the Warren Unit Number 9.

Q. 15 through 24 are individual formulas for each of the wells?

A. Correct.

Q. And they're all done the same way?

A. Correct.

Q. Let's take 15, then, as the example to discuss and have you describe for me your method.

A. Okay. On the Warren Unit Number 9, here, you have again the year column on the left, Blinebry-Tubb production in barrels of oil per day in the next column, Drinkard production in barrels of oil per day in the next column.

Then you have the combined total in the next column of the Blinebry-Tubb and the Drinkard. And then next, you've got percent Blinebry-Tubb and percent Drinkard for those respective years.

This information was based upon decline-curve analysis for the gas and the oil. What we just looked at in the top portion of this page was the oil, down below is the gas portion. And they were both done the same for all of these wells.

Q. If you were to share personally in receiving production, would you be satisfied with receiving production based upon an allocation formula like this?

A. Yes, I would.

Q. Do you believe it's a fair and accurate means by way of apportioning commingled production so that the owners in each participating area receive their fair and appropriate share of that production?

A. Yes, I would.

Q. Identify for us what is contained in Exhibit 25.

A. Exhibit 25 are the C-116s for all of these wells, showing the gas-oil ratio tests, and it's basically using the same numbers that we've shown on our previous exhibit with the current productivity tests.

Q. All right, sir, and Exhibit 26, identify 26 for us.

A. Exhibit Number 26 are the Blinebry-Tubb oil and gas production curves that I discussed earlier that were used to come up with the allocation formulas.

Q. All right, sir, and Exhibit 27 is what?

A. Exhibit 27 are the same oil and gas production curves that were used to come up with the Drinkard allocation formula, portion of the formula.

Q. All right. We've got some new information for production information for Wells 113 and 115. Has that information been incorporated into the allocation sheets for those wells?

A. Yes, it has.

Q. On the allocation formulas?

A. Yes.

Q. Have we amended the --

MR. HOOVER: No.

Q. (By Mr. Kellahin) We haven't yet?

A. Oh, no, I'm sorry --

Q. All right.

A. -- I'm sorry, I didn't understand your question. No, they haven't.

Q. All right. For Well 115, if we look at Exhibit 24, this allocation formula needs to be changed, right?

A. That's correct.

Q. Because you've got new test data --

A. That's correct.

Q. -- that's going to change the allocation?

A. That's correct.

MR. KELLAHIN: All right. Mr. Examiner, we will submit to you, sir, following the hearing, with your permission, the new allocation formulas as substitute exhibits for Exhibit 24, and then for Exhibit 22.

And with those corrections, then, the allocation formulas will be consistent with the latest available production information prior to commingling.

Q. (By Mr. Kellahin) Exhibit 25 is what, sir? It's a C-116, that's our --

A. Yeah, we just went over that.

Q. All right. I think we're ready for Exhibit 28, then.

A. Correct.

Q. Identify for the record what Exhibit 28 is.

A. Exhibit 28 is the completion histories and wellbore diagrams for the recent completions on the 113, 114 and 115.

Q. All that information is information that would otherwise be required for an administrative application?

A. That's correct.

Q. And you've simply tabulated it and spent the effort to provide it for the Examiner for his review?

A. That's correct.

Q. The final exhibit, would you identify that for us?

A. Yeah, this is the Warren Unit interest owners, a list of the interest owners and their interests, and it also includes the registered mail receipts that -- showing that they were sent to all of these working interest owners.

Q. So any working interest owner, whether it's in the Drinkard or an interest ownership in the Blinebry-Tubb, would be on this notification list?

A. That's correct.

Q. In addition, if you'll turn to page 3 of the list, there is an offset operator, apparently only one, Exxon?

A. That's correct.

Q. And they received notification because they're an offset operator?

A. That's correct.

Q. Are you aware of any of the interest owners or the offset operator registering any objection to approval of the Application?

A. No, I'm not.

MR. KELLAHIN: That concludes my examination of

Mr. Barrett.

We move the introduction of his Exhibits, which are Exhibits 5 through 29.

EXAMINER CATANACH: Exhibits 5 through 29 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Barrett, to your knowledge are there any overriding royalty interest owners in this unit?

A. Yes, there are.

Q. Did you notify the overriding royalty interest owners?

MR. KELLAHIN: Yes, sir --

THE WITNESS: Yes.

MR. KELLAHIN: -- if you'll look at the first page of 29, there will be a caption that will tell you the type.

Q. (By Examiner Catanach) Okay, and it's all federal royalty, it's all federal lands within the unit?

A. Yes.

Q. Okay. Do you in fact know that the participating areas within this unit are not the same?

A. Yeah, that's correct.

Q. Okay, so there could be some difference in ownership between some of these zones?

A. That's right.

Q. Mr. Barrett, your proposed allocation formulas with respect to the wells that are in Sections 27, 33 and 34, those being the waterflood wells, did you address those in a special manner?

A. No, I addressed those in the same manner that I did all of the others. And part of the reason for that is, right now we see no reason to do otherwise, currently.

Q. Have you -- In those wells have you seen a response to waterflood operations?

A. No, we haven't.

Q. Do you expect to?

A. Yes.

Q. So the production volumes should change in those wells?

A. Yes.

Q. Did you take that into account when doing the allocation formula?

A. No, I didn't.

One thing to add with that, though, for -- In Section 27, our expansion has not -- We haven't completed our expansion there, so there will be a delay in that response, meaning we have not taken all of our injectors all the way over to Section 28.

Q. Mr. Barrett, do you know where the -- Let me ask you this: Is this the Warren-Drinkard Pool we're dealing with in Section 28?

A. That's correct.

Q. Does it extend beyond Section 28?

A. Yes, it does. It extends down in Section 33, just like we have marked in gold or orange, whichever, and also the 40-acre unit letter D in Section 34.

Q. As far as you know, there is no Drinkard production from this pool outside of the Warren unit?

A. There was earlier on, there as a Mobil well, and I think it discontinued production in the late Fifties.

Q. Do you know or do you have an opinion as to whether there's any potential for Drinkard production outside the unit from the Warren-Drinkard Pool?

A. Not from what we've seen. With that oil-water contact at minus 3250, you run out of productive interval very quickly.

Q. So basically if you're allowed to produce at a higher GOR in Section 28, you're not really having an effect on the correlative rights of any other operator at the present time?

A. That's correct.

Q. And you don't think that that will be an issue?

A. No, I don't.

Q. Mr. Barrett, I believe you -- You stated an opinion that production at a higher GOR in Section 28 is not going to reduce the ultimate oil recovery from the reservoir?

A. That's correct.

Q. What do you base that on?

A. Based on reservoir analysis of solution gas drive reservoirs, it just -- From just the way they operate, it's not a gas cap or a gas drive with that, and therefore withdrawing it any quicker does not hurt the recovery of that reservoir.

Q. You didn't run any kind of simulations, or have you had any experience with running any kind of simulations on these type of reservoirs?

A. Not on this particular reservoir. I have done it on another one that we've got under waterflood.

Q. And what did that show you?

A. It showed me there shouldn't be any problem.

Q. You're not going to get reduced oil recovery?

A. That's right.

Q. I missed -- I believe you said that you were going to try and shut off some water on one of these wells?

A. Yes, it was Well Number 97. That was one where we perforated below that oil-water contact, and it makes 102 barrels of water per day -- or it did, its last test did in early 1994.

And with that, if we did get approval to downhole commingle that, once we went back in there we would attempt to squeeze off that extra water production.

Q. Do you have any idea what kind of producing rates you will encounter in the four wells that you will drill?

A. Yes, I do. I feel that as Mr. Nelson stated earlier, that structure is significant. And from what we've seen, based on our lower-structure wells, I think they'll be very similar. I think the -- as I proposed in the economics, the six barrels a day and a couple hundred MCF are going to be very typical rates.

Q. That's combined rates?

A. No, I'm sorry, not combined. That would be just from the Drinkard alone.

Q. From the Drinkard.

A. Yes.

Q. What kind of rates do you anticipate from the Blinebry-Tubb?

A. Blinebry Tubb has been real good with these newer wells. There is the potential of right at the start 50 to 70 barrels a day and 500 to 700 MCF, and these are just rough numbers.

I feel that they probably would be above an administrative downhole commingled rate.

Q. But these would still be uneconomic as far as dual completions would be concerned?

A. That's correct.

Q. Mr. Barrett, what would be the -- at the time when waterflood operations are commenced in Section 28, what would be Conoco's plan to deal with the Drinkard? Would that just be abandoned at that time?

A. Yes, it would.

EXAMINER CATANACH: I think that's all I have.

MR. KELLAHIN: That concludes our presentation.

EXAMINER CATANACH: Okay, you're going to supplement the record, Mr. Kellahin, with some additional --

MR. KELLAHIN: Yes, sir, there's two allocation formulas that need to be replaced, and with your permission we'll do that.

EXAMINER CATANACH: Okay.

MR. KELLAHIN: I am not aware of anything else we would submit. If there's things that you would like us to do, we would certainly be happy to do it.

EXAMINER CATANACH: Yes, there is, Mr. Kellahin.

MR. KELLAHIN: Yes, sir, well, give us your list.

EXAMINER CATANACH: Since we are on such severe time constraints on these orders, I would appreciate a rough draft --

MR. KELLAHIN: Smooth rough or rough rough?

EXAMINER CATANACH: -- within ten days. We'll put time constraints on you guys too.

MR. KELLAHIN: Would you like rough rough or do you want smooth rough?

EXAMINER CATANACH: Smooth rough.

MR. KELLAHIN: Smooth rough. We can do that.

EXAMINER CATANACH: Okay. There being nothing further in this case, Case 10,897 will be taken under advisement.

(Thereupon, these proceedings were concluded at 12:18 p.m.)

* * *

CERTIFICATE OF REPORTER

STATE OF NEW MEXICO)
) ss.
COUNTY OF SANTA FE)

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL March 6th, 1995.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11212, heard by me on March 2 1995.

David R. Catanach, Examiner
Oil Conservation Division