STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

RECEIVED

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

APPLICATION OF YATES PETROLEUM CORPORATION FOR AMENDMENT OF THE SPECIAL POOL RULES AND REGULATIONS FOR THE NORTH DAGGER DRAW-UPPER PENNSYLVANIAN POOL AND FOR THE CANCELLATION OF OVERPRODUCTION, EDDY COUNTY, NEW MEXICO — CASE NOS. 11,525

APPLICATION OF YATES PETROLEUM CORPORATION FOR AMENDMENT OF THE SPECIAL POOL RULES AND REGULATIONS FOR THE SOUTH DAGGER DRAW-UPPER PENNSYLVANIAN POOL AND FOR THE CANCELLATION OF OVERPRODUCTION, EDDY COUNTY, NEW MEXICO — and 11,526

(Consolidated)

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS
EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

May 3rd, 1996
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MICHAEL E. STOGNER, Hearing Examiner, on Friday, May 3rd, 1996, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

May 3rd, 1996
Examiner Hearing
CASE NOS. 11,525 and 11,526 (Consolidated)

* * *

E X H I B I T S

Applicant's - Case Nos. 11,525 and 11,526 (Consolidated)

	Identified	Admitted
Exhibit 1	12	16
Exhibit 2	14	16
Exhibit 3	15	16
Exhibit 4	26	56
Exhibit 5	28	56
Exhibit 6	32	56
Exhibit 7	34	56
Exhibit 8	38	56
Exhibit 9	40	56
Exhibit 10	43	56
Exhibit 11	46	56
Exhibit 12 (does not exist)		
Exhibit 13	49	56
Exhibit 14	53	56

* * *

Conoco - Case No. 11,525

	Identified	Admitted
Exhibit 1	134	146
Exhibit 2	137	146
Exhibit 3	141	146
Exhibit 4	144	146
Exhibit 5	158	169
Exhibit 6	158, 162	169
Exhibit 7	162	169
Exhibit 8	162	169
Exhibit 9	162, 163	169

(Continued...)

E X H I B I T S (Continued)

Conoco - Case No. 11,525

	Identified	Admitted
Exhibit 10	162	169
Exhibit 11	162	169
Exhibit 12	162, 164	169
Exhibit 13	162	169
Exhibit 14	162	169
Exhibit 15	162	169
Exhibit 16	162	169
Exhibit 17	162	169
Exhibit 18	162	169
Exhibit 19	165	169
Exhibit 20	165	169

Conoco - Case No. 11,526

	Identified	Admitted
Exhibit 1	181	187
Exhibit 2	181	-
Exhibit 3	181	-
Exhibit 4	181	-
Exhibit 5	181	-
Exhibit 6	181	-
Exhibit 7	181	187
Exhibit 8	181	187
Exhibit 9	181	187
Exhibit 10	181	187
Exhibit 11	181	187
Exhibit 12	181	187
Exhibit 13	181	187
Exhibit 14	181	187
Exhibit 15	181	187

(Continued...)

EXHIBITS (Continued)

Conoco - Case No. 11,526

	Identified	Admitted
Exhibit 16	181	187
Exhibit 17	181	187
Exhibit 18	181	187
Exhibit 19	181	187
Exhibit 20	181	187
Exhibit 21	181	187

* * *

APPEARANCES

FOR THE DIVISION:

RAND L. CARROLL
Attorney at Law
Legal Counsel to the Division
2040 South Pacheco
Santa Fe, New Mexico 87505

FOR THE APPLICANT and NEARBURG EXPLORATION COMPANY:

CAMPBELL, CARR, BERGE and SHERIDAN, P.A.
Suite 1 - 110 N. Guadalupe
P.O. Box 2208
Santa Fe, New Mexico 87504-2208
By: WILLIAM F. CARR

(Continued...)

A P P E A R A N C E S (Continued)

FOR CONOCO, INC.:

KELLAHIN & KELLAHIN
117 N. Guadalupe
P.O. Box 2265
Santa Fe, New Mexico 87504-2265
By: W. THOMAS KELLAHIN

FOR JAMES T. CHAVEZ:

PADILLA LAW FIRM, P.A.
1512 South St. Francis Drive
P.O. Box 2523
Santa Fe, New Mexico 87504-2523
By: ERNEST L. PADILLA

FOR MARATHON OIL COMPANY (Case No. 11,526 only):

MONTGOMERY & ANDREWS, P.A.
325 Paseo de Peralta
P.O. Box 2307
Santa Fe, New Mexico 87504-2307
By: EDMUND H. KENDRICK

FOR MEWBOURNE OIL COMPANY:

HINKLE, COX, EATON, COFFIELD & HENSLEY
218 Montezuma
P.O. Box 2068
Santa Fe, New Mexico 87504-2068
By: JAMES G. BRUCE

* * *

WHEREUPON, the following proceedings were had at 8:00 a.m.:

EXAMINER STOGNER: This hearing will come to order. Welcome to the continuation of Docket Number 13-96.

At this time I'm going to consolidate and call both Cases 11,525 and 11,526.

MR. CARROLL: Application of Yates Petroleum Corporation for amendment of the special pool rules and regulations for the North Dagger Draw-Upper Pennsylvanian Pool and for the cancellation of overproduction, Eddy County, New Mexico.

And the Application of Yates Petroleum Corporation for amendment of the special pool rules and regulations for the South Dagger Draw-Upper Pennsylvanian Pool and for the cancellation of overproduction, Eddy County, New Mexico.

EXAMINER STOGNER: At this time I'll call for appearances.

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe law firm Campbell, Carr, Berge and Sheridan.

We represent Yates Petroleum Corporation in this matter, and I have two witnesses.

And I would also like to enter my appearance for Nearburg Exploration Company.

EXAMINER STOGNER: Other appearances?

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin.

I'm appearing today on behalf of Conoco, Inc., and I have two witnesses to be sworn.

MR. PADILLA: Mr. Examiner, I'm Ernest L. Padilla, Santa Fe, New Mexico, for James T. Chavez.

MR. KENDRICK: Mr. Hearing Examiner, I'm Ned Kendrick with the Montgomery and Andrews law firm in Santa Fe, representing the Marathon Oil company in the second of those two Applications, the South Dagger Draw Application.

No witnesses.

MR. BRUCE: Mr. Examiner, Jim Bruce from the Hinkle law firm in Santa Fe, representing Mewbourne Oil Company.

I do not have any witnesses.

MR. PADILLA: Mr. Examiner, I don't have any witnesses.

EXAMINER STOGNER: Mr. Kellahin --

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: -- how many witnesses do you have?

MR. KELLAHIN: Two.

EXAMINER STOGNER: And Mr. Carr?

MR. CARR: Two witnesses.

EXAMINER STOGNER: Mr. Carroll, do you know if the Division -- or do you have any plans of calling a witness for the Division?

MR. CARROLL: Mr. Examiner, the Division may call a witness.

EXAMINER STOGNER: Okay. At this time, why don't we swear in all witnesses or all possible witnesses? We'll have everybody stand.

(Thereupon, the witnesses were sworn.)

EXAMINER STOGNER: Gentlemen, proceedings in this matter? Do we need to just start right in, or is there any need for opening remarks?

MR. CARR: I'm ready to go.

MR. KELLAHIN: Let's put on some witnesses.

EXAMINER STOGNER: Okay.

MR. CARR: At this time we'd call Mr. Brent May.

BRENT MAY,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?

A. Brent May.

Q. Mr. May, where do you reside?

A. In Artesia, New Mexico.
Q. By whom are you employed?
A. Yates Petroleum.
Q. What is your current position with Yates?
A. I'm a geologist.
Q. Have you previously testified before this Division?
A. Yes, I have.
Q. At the time of that testimony, were your credentials as an expert in petroleum geology accepted and made a matter of record?
A. Yes, they were.
Q. Are you familiar with the Application filed in each of these cases on behalf of Yates Petroleum Corporation?
A. Yes, I am.
Q. Are you familiar with the status of the ownership in these pools?
A. Yes, I am.
Q. Mr. May, have you made a geological study of the Canyon or upper Pennsylvanian formation in this area?
A. Yes, I have.
MR. CARR: Are the witness's qualifications acceptable?
EXAMINER STOGNER: Any objection?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: They are.

Q. (By Mr. Carr) Could you briefly state what Yates Petroleum Corporation seeks in these cases?

A. In Case 11,525, the North Dagger Draw Pool, we're asking for a special depth bracket allowable of 4000 barrels of oil per day for each 160-acre proration unit. We're also asking for the cancellation of all overproduction in the pool on the date that the requested depth bracket allowable become effective.

In Case 11,526, which is South Dagger, we're asking for a special depth bracket allowable of 8000 barrels of oil per day for each 320-acre proration unit, and also, again, the cancellation of all overproduction in the pool on the date the requested depth bracket allowable becomes effective.

Q. Could you just initially summarize the important provisions of the rules which currently govern development in each of these two pools?

A. Currently in North Dagger the spacing is 160 acres, the depth bracket allowable is currently 700 barrels of oil per day, and the GOR is 10,000 to 1.

In South Dagger the spacing is 320 acres, and the depth bracket allowable is 1400 barrels of oil per day, and the GOR is 7000 to 1.

Q. Have you prepared exhibits for presentation here today?

A. Yes, I have.

Q. Let's go to what has been marked for identification as Yates Exhibit Number 1. I'd ask you to identify this exhibit and then review the information thereon.

A. This is basically a computerized land map of North and South Dagger Draws, showing the different townships.

The different well spot locations have different colors. The black spots represent wells operated by Yates Petroleum, the blue well spots represent wells operated by Conoco, the purple well spots represent wells operated by Nearburg. And in general the yellow well spots represent all others, but in the case of South Dagger, the majority of those operated by Marathon Oil.

The different proration units are shown in each pool. In North Dagger they're 160s and in South Dagger they're 320-acre proration units.

You might note that in one of the various corners of the different proration units are colored triangles. Those represent the two -- In the position of the corner -- in other words, if it's the upper right-hand, versus upper left-hand, versus lower left-hand -- determines who the operator of the proration unit is.

The color of the triangle actually denotes percentage ranges of that operator. And if we can look at the bottom of the map, at the legend, it will point that out. We might note, though, that there is an error on this legend. If you read through above the triangles, it says upper right for all. It should be --

Q. If we come down the left side of that block that has all the triangles in it, in the upper left-hand corner it says "upper right".

A. Right.

Q. Is that correct?

A. Only in the top case.

Q. Okay. If we go directly below that to the blue triangle where it says upper right, what should that say?

A. It should say upper left-hand corner of proration unit -- Conoco-operator percentage. And on the bottom one it should say lower -- I believe it is lower left-hand proration unit, Nearburg is the operator.

Q. Okay. And other than that, it's correct; is that right?

A. Yes, and as I stated before, the different colors show percentage ranges of the operator's percentage, blue zero to 25 percent, green 26 to 50 percent, and yellow 51 to 75 percent and the red 76 to 100 percent.

Also, for each proration unit out of the major operators in the different corners, the rough percentages are shown, even if they are -- the different company is not the operator. So you can look at three different corners and show the percentage that Yates has, the percentage Conoco has and the percentage Nearburg has.

Q. This is actually the in-house map that Yates uses to keep track of the operators and spacing units in this pool; is that not correct?

A. That's true. There's a lot of information on here, and it's kind of busy. But once you get a hang of it, it's a very good map that has a lot of information that you can go to quickly with one glance.

Q. And this plat shows all wells and well locations within the two pools?

A. Yes, it is.

Also note that the dark black line is roughly the outline of the Canyon dolomite or upper Penn dolomite here.

Also note that down in South Dagger, in Sections 14 and 23 of 20 South, 24 East, it also shows the Sawbuck pilot waterflood project.

Q. All right, Mr. May, let's go to Yates Exhibit Number 2. Will you identify and review that?

A. This is a net dolomite isopach of the Canyon or upper Penn dolomite, throughout South and North Dagger

Draw.

The red dots represent the various wells within the different pools within the colored area. The contour intervals are 50-foot contour intervals, but we have different colors which denote 100-foot contour intervals. And you can note from the light blue to darker blues into the green that goes from the edge to thin dolomite to thicker dolomite, the green being the thickest.

The main thing I want to show with this exhibit is that North and South Dagger Draw are in the same continuous geologic body, the same -- the Canyon dolomite, and that's one of the reasons why we have asked for both South and North Dagger Draw to be -- the changes we have -- we will ask for. That's why we've asked for both of them, because it's in the same geologic unit.

And I do want to point out that even though it's the same geologic body, there are variations within this body as far as reservoir qualities go, but it is one continuous dolomite body. In fact, this dolomite body even continues down into Indian Basin, in that area, and I think that's been pointed out in several hearings in the past.

Q. Mr. May, is Exhibit Number 3 an affidavit confirming that notice of this Application has been provided in accordance with Division rules?

A. Yes, it is.

Q. And attached to that, do we have an exhibit identifying those individuals and a copy of the notice letter?

A. Yes.

Q. To whom was notice provided?

A. It was provided to all the operators in the pools, all unleased mineral owners in the pools, and operators in the upper Penn formation within a mile of the pool boundaries.

Q. Is Yates going to also call an engineering witness to review those portions of these Applications?

A. Yes, we will.

Q. Were Exhibits 1 through 3 either prepared by you or compiled at your direction?

A. Yes, they were.

Q. Can you testify as to the accuracy of Exhibits 1 through 3?

A. Yes.

MR. CARR: At this time we would move the admission into evidence of Yates Exhibits 1 through 3.

EXAMINER STOGNER: Any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Exhibits 1 through 3 will be admitted into evidence.

MR. CARR: That concludes my direct examination of Mr. May.

EXAMINER STOGNER: Thank you, Mr. Carr. Mr. Kellahin, your witness.

MR. KELLAHIN: No questions.

EXAMINER STOGNER: Mr. Padilla?

MR. PADILLA: I don't have any.

EXAMINER STOGNER: Mr. Kendrick?

MR. KENDRICK: No questions.

EXAMINER STOGNER: All right, Mr. Bruce has left the room.

MR. CARR: I'm glad that's on the record.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. May, in -- Points of procedure. In Exhibit Number 1, up in the North Dagger Draw, you have solid well symbols and hollow well symbols, and then you've got some gas-well symbols. Could you maybe go into a little more detail about what each depicts?

A. Sure, the solid well symbols are the upper Penn producers. The open well symbols are locations, proposed locations. And the gas-well symbols, most of those gas wells, I believe, are producing out of the Morrow formation. So they are not out of the Upper Penn, the gas-well symbols.

Q. Like take, for instance, in Section 20 of 19-25, you look down in the southwest corner, and in the northeast quarter of the southwest quarter there is a solid gas-well symbol.

A. Okay, I should explain that. Probably what -- If I remember correctly, that well may have originally been an old Morrow well and then was later recompleted to the Upper Penn. The way the computer takes the data, a lot of times, it doesn't wipe out the old data, so it overprints on the older data.

Q. Would it be fairly easy to say that if it's solid, then that means it's a producing oil well in that pool?

A. That is correct.

Q. Okay. In Exhibit Number 2, you're showing the continuity or the continuation of this trend that takes in North Dagger Draw and the South Dagger Draw.

If you extend that on down, doesn't that take in another pool?

A. It takes in Indian Basin Pool, and also the Indian Basin Associated Pool.

EXAMINER STOGNER: I feel it's necessary to take administrative order at this time, Mr. Kellahin on -- I'm sorry, Mr. Carr and Mr. Kellahin -- previous orders.

MR. CARR: Yes, sir.

EXAMINER STOGNER: If I remember right, the development of this pool, at least setting the allowables, has fairly well gone hand in hand.

I can't remember the order numbers now, or even the case numbers, but --

MR. CARR: We can provide you with a list of those.

And we have certainly no objection to your taking administrative notice of any of the previous cases --

EXAMINER STOGNER: Would you please? And I believe there is a pending order or a pending case to step the allowable in the Indian Basin Associated Pool --

MR. CARR: Yes, sir.

EXAMINER STOGNER: -- to make that in line with the current pool rules?

MR. CARR: Mr. Stogner, if it's all right, we'll prepare a list of those cases, and I'll review it with the other attorneys in the case, and with their concurrence, we'll submit it to you and try to have as complete a listing as possible.

EXAMINER STOGNER: Okay. With that, I have no other questions of Mr. May.

MR. CARR: And at this time, then, that concludes our geologic presentation, and we would call Mr. Robert Fant.

EXAMINER STOGNER: Mr. Carr?

ROBERT S. FANT,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?

A. Robert Fant.

Q. Where do you reside?

A. Artesia, New Mexico.

Q. By whom are you employed?

A. Yates Petroleum Corporation.

Q. Mr. Fant what is your current position with Yates Petroleum Corporation?

A. I'm a petroleum engineer.

Q. Have you previously testified before this Division?

A. Yes, I have.

Q. At the time of that testimony, were your credentials as an expert witness in petroleum engineering accepted and made a matter of record?

A. Yes, sir, they were.

Q. Are you familiar with the Applications filed in each of these cases on behalf of Yates Petroleum Corporation?

A. Yes, sir, I am.

Q. Are you familiar with the engineering aspects of the development of both of these pools?

A. Yes, sir.

Q. Are you the engineer responsible for Yates -- for the engineering aspects of the development of the Dagger Draw pools?

A. Yes, sir.

MR. CARR: Are the witness's qualifications acceptable?

EXAMINER STOGNER: Any objections?

MR. KELLAHIN: No objection.

Q. (By Mr. Carr) Mr. Fant, initially could you summarize the events which have resulted in these cases being before Examiner Stogner on this date?

A. Well, you know, to look back on some of the history, we've known and it's been known that wells within these pools at times are capable of producing at high rates immediately after completion.

The norm in history was that they would decline very rapidly and usually within the first month they would be below allowable, and so there was no conflict with allowables.

But some of the recently drilled wells have not experienced the rapid decline rates that were present in some of the earlier rates. You know, this was -- this began shortly before I took on the responsibilities of the reservoir engineering in Dagger Draw. We completed some of these wells that were of this type.

And last summer (1995) I went to the OCD and discussed the potential of running some tests, because I had some concerns about restricting wells and whether or not that was good for ultimate oil recovery. And we knew at the time that the wells were producing at rates above allowable. We discussed it with the OCD. The parameters needed to run the tests were not -- we were not able to put those together at the time, and so the tests basically were never run.

And you know, everybody was kind of expecting these wells to pretty soon fall on their face and just go on decline pretty rapidly. So, you know, there was knowledge that the wells were in an overproduced status. The extent was not really known.

Recently, the ONGARD system kicked it out, and Mr. Gum came and met with representatives of Yates Petroleum, Mr. Collins, our new operations manager, to -- you know, brought it to Brian's attention.

We formulated a plan at that point, and basically that's brought us to this --

Q. What was the actual result of that meeting between representatives of the Artesia Office of the OCD and representatives of Yates?

A. Well, the first thing we did was, we filed these Applications. That was one of the first things we had -- you know, I had been somewhat aware of this -- my concerns about how to produce the wells in Dagger Draw, for a while now, and so we immediately took this -- you know, filed these applications.

And upon meeting with Mr. Gum we curtailed the production within these overproduced proration units to the 700-barrel-a-day allowable or, in some cases, they were curtailed -- they were not curtailed, in some cases they were below, already below the 700-barrel-a-day allowable. The ones that were still above that 700-barrel-a-day, we curtailed to allowable so as to not increase the effects of overproduction or the magnitude of the overproduction, pending the results of this hearing.

Q. Was it your understanding that Mr. Gum was also visiting with other operators in the pool who had wells that were overproduced?

A. Yes, it was our understanding.

Q. What can an operator do when they find themselves in this situation with wells that are substantially overproduced?

A. Really, they have two options: They can curtail production, or they can seek special relief from the

Division. And basically we had taken both of those steps already.

Q. Have you prepared exhibits for presentation here today?

A. Yes, sir, I have.

Q. And as you present this data this morning, are you presenting new information about these pools, talking about things that were not known before?

A. The basics of what I'm talking about has been known for many years in Dagger Draw on an empirical basis. It's been some basic tenets that people have talked about since the early days of one of the first operators. You know, we call them the Roger Hanks days. He was one of the first operators in the pool and had a lot to do with some of the early orders within the pool.

Q. When did the real production in this pool take off?

A. Well, you know, it was discovered around 1972, but it was the mid- to late-1980s before production techniques and knowledge of the pool increased enough to where significant development and, you know, massive production rates were seen in this pool.

Q. And what was causing this delay in developing this significant production?

A. Well, really, early in the life of the pool, operators seemed to show a hesitancy to move large volumes of fluid. You -- And as a result, they were seeing very, very high water cuts within -- for their production in relation to -- many of them did not have the saltwater disposal capacity, the pump technology. They were -- The pump technology used at the time was not the same as the technology we're using these days.

And consequently, they were simply not moving the volumes of fluid necessary to get attractive oil cuts within the wells and to get attractive economics for the wells, and we finally moved into the stage of doing that.

Q. You're going to be presenting evidence this morning about the higher oil cuts that result from the increased production, right?

A. Yes, sir.

Q. Was that something that was understood back in the early days of this pool?

A. I believe there was some understanding of it, but I don't feel that the operators were willing to go out at the time and, either through technology or through capacity of their disposal systems, to actually move the fluids.

Q. Let's go to Yates Exhibit Number 4.

A. Okay.

Q. Would you identify this exhibit for Mr. Stogner and review the information on the exhibit?

A. Okay, Exhibit Number 4 is a plot entitled Swabbing Oil Cut Versus Second Month Producing Oil Cut for 58 Wells in Dagger Draw.

I reviewed the drilling reports and determined basically what was the oil cut during -- immediately after completion, when we were swabbing on the well, and that oil cut is represented on the X axis. And the oil cut is simply just the percentage of the -- It's just oil volume divided by oil-plus-water volume, and it's represented as a percentage here.

And basically when you're swabbing or flowing these wells, we were generally producing at a rate of about 500 barrels of fluid a day, which represents a small drawdown for production in the Dagger Draw reservoir. In general, that's a small drawdown. 500 barrels of fluid a day is a small amount of fluid for these wells to produce. That is the X axis.

When you look at the Y axis, that is the producing oil cut reported for the second month of production, and that represents high drawdowns and high fluid rates.

Q. Why did you use the second-month production?

A. I used the second month because there's a tendency for the first month, in terms of oil cuts, to be somewhat inaccurate. When you're completing the well in these wells, you often -- you may recover 200 or 300 barrels of oil. You may swab them for a while, or they may flow well.

The water that's produced during the completion phase, before the well is actually IP'd, is seldom reported. And so you can get -- But the oil is reported as first -- when the first month of production. So you can actually -- If you use the first month of production, you can get inaccurate numbers for what the oil cut for the well actually is.

So that's why I've gone to the second month. I wanted to look at a time period where depletion hasn't become a major factor in the well, but -- And I didn't want to use that first month, because I consider it inaccurate at times.

Q. Okay. Now, comparing those two things, what does this exhibit show you?

A. Basically what this exhibit shows is that the oil cuts you see when you're swabbing, you almost always see a significantly higher oil cut when the well is put on production.

You know, for example, you might have a 10-percent oil cut on -- when you're swabbing the well, but the oil cut, you know, there's -- if you go up this 10-percent line, there's a well that's producing at over 66-

percent oil cut when placed on production.

You know, there's no direct correlation. I can't say that if you have a 5-percent oil cut on swab, you'll get a specific oil cut on production. But you get that oil cut, essentially, or higher.

There's a couple or three or four wells that fall in the other direction, but they're -- I mean, really, there's only two that fall significantly below that, you know, and that would put it in the 90-plus percentile range on this particular thing, for -- over 90 percent of the time, you see this effect.

Q. What we've got here is production figures early in the life of each of these wells, right?

A. Yes.

Q. And when you compare low producing rates on swabbing or early flowing to high producing rates during the first reliable month of production, you're seeing that -- high production rates, you're also getting high oil cuts; isn't that correct?

A. Yes, sir.

Q. Okay. Let's go to Exhibit Number 5. Would you explain what that is?

A. Exhibit Number 5 is a collection of plots for -- and basically what I'm plotting here is the oil cut on the Y axis as a function of the oil rate, producing oil rate, on the X axis. And this is a well that at one point produced well above allowable.

Q. You're talking about the first well in this exhibit?

A. Yes, sir, the --

Q. We've got 17 here; is that right?

A. There's 17 wells in this exhibit, and I'm basically going to talk about them in generic terms, but I'm providing the 17 wells as multiple examples of the same effect.

What I was trying to look at here is, we saw in this -- in Exhibit Number 4 that there appears to be a relationship between drawdown and oil cut. When you have the higher drawdown you have a higher oil cut, or when you have a higher producing rate you have a higher oil cut.

On these graphs -- We know that throughout time in these wells, that as decline continues we have a smaller amount of drawdown available to us. As reservoir pressure decreases, the differential pressure between the reservoir and the wellbore goes down, fluid rates go down.

So if this particular phenomenon that we saw in Exhibit 4 continued throughout the reservoir, then if we plot the oil rate -- I mean, if we plot oil cut versus oil rate for these wells throughout their time, there should be a relationship between oil cut and oil rate. In other words, as oil rate goes down, oil cut should go down. And that's -- You know, that's what I've looked at here.

These particular wells are some of the best wells in the pool. They -- Basically, you know, my criterion for primarily looking at these was to look at wells that had produced at or near or above the allowable at some point and to see if this relationship maintains itself throughout time. And if the relationship we saw in Exhibit 4 holds true, then the slope of these points, of a regression through these points, should have a positive slope. And in all 17 of these cases, it does. You know, the magnitude of it changes a little bit.

In fact, there's an equation on here of the regression through these -- linear regression, it's just a statistical regression through them, and the equation is plotted on there, and in all cases that I've shown you here, it has a positive slope.

Q. Are most of these wells in the recently developed portions of these pools?

A. Absolutely, these are within like the last two years, primarily.

Q. We've got 17 wells here, but how many proration units are actually overproduced that you operate at this time?

A. There are 10 proration units that at this time are overproduced. When it was brought to our attention there were 11, but one of those has been corrected.

Q. When we look at these 17 wells, are these all in North or South Dagger, or do you have wells that are actually in each of these pools?

A. I believe this particular set of examples are in North Dagger Draw. I just want to look through them here. These particular wells that -- No, there's one in South Dagger Draw, so this does incorporate both of them.

Q. Have you actually plotted the data, not just on these 17 wells, but on all wells in these two pools?

A. Yes, sir, I have -- There's approximately three hundred and six or seven wells for which I have data in this pool, enough data to construct this type of plot, and I have looked at the plot for every well in Dagger Draw. I did not want to submit 300 examples; it might get a little cumbersome.

Q. We will pursue that in a minute. But when you have plotted these curves --

A. Uh-huh.

Q. -- on each of these wells, what are you looking for? A positive or a negative slope?

A. In this instance, I'm looking to see if there is a positive slope.

Q. And if you have a positive slope, does that confirm that at high rate you have a high oil cut?

A. For that well, yes, sir, that confirms it.

Q. And why is that important? Why is it important to have a higher oil cut?

A. Well, it's a conservation of reservoir energy. And it's been presented many times. We want to produce the maximum amount of liquid hydrocarbon oil for the minimum amount of reservoir energy taken out of the reservoir. In other words, we want to minimize the water production per barrel of oil, or we want to maximize the oil cut.

Q. Now, Mr. Fant, each of these 17 plots has a positive oil-cut slope, does it not?

A. Yes, sir.

Q. Does your next exhibit, Exhibit 6, indicate whether or not you've been able to achieve a positive or negative slope on each of the wells in the pool?

A. Yes.

Q. Let's go to that exhibit, and I'd ask you to review it for the Examiner.

A. Okay.

MR. KELLAHIN: What's the exhibit number?

MR. CARR: Exhibit Number 6.

THE WITNESS: Exhibit Number 6 is the table of wells, and it's six pages long. It's a table for each one of the -- allowing for each one of the wells that I have evaluated in Dagger Draw. They're listed alphabetically. There may be some wells that are in the pools that are not included here. That would simply be because I don't have enough data to construct one of these plots.

And on this, when you look at this exhibit, we have, going from left to right, we have well name, who the operator is, its location by unit, section, township and range.

And then we have a column that I have called the oil-cut slope, okay? And that is the slope of the line, as you see -- the line similar to what we saw on Exhibit 5. You know, each one of these plots has a slope to that line, and that slope has been calculated for every well in Dagger Draw and presented in this column.

The biggest thing I want to point out here is that 95 percent of the time, that number is positive, greater than zero. 95 percent of the time we have this positive slope, like we saw over here in the Exhibit Number 5. 95 -- And actually it's a little over 95 percent. But that much of the time, this relationship holds true in both pools. These wells are both North and South Dagger Draw, these that are presented here in Exhibit 6.

Q. (By Mr. Carr) Exhibit 4 was an example of a positive slope early in the life of these wells. That is, when you produce them at high rates early, you have higher oil cut; is that --

A. Absolutely.

Q. And Exhibit Number 6 is, in fact, confirmation of that over a longer producing period; is that right?

A. Yes, this says that when you look at the effects of depletion, when depletion is causing the lower rates, that phenomenon holds true.

Q. Are you comfortable with saying that, in your opinion, during the life of this reservoir if you produce at higher rates, you have a higher oil cut?

A. Yes, sir.

Q. Is that a more efficient way to produce the oil in each of these pools?

A. Absolutely.

Q. Let's go to what has been marked Yates Exhibit Number 7. Can you identify that, please?

A. Okay, Yates Exhibit Number 7 is very similar to the plots presented in Exhibit Number 5. We have the same oil rate on the X axis and oil cut on the Y axis.

However, in this particular instance, the data points plotted here are daily oil rates. They were -- You know, Exhibit 5, the data points were for the month, they were a monthly average. This is data specifically for the daily -- early life of the well.

Q. Now, Mr. Fant, you've got two wells --

A. Yes.

Q. -- in this exhibit?

Q. How are these wells different from the wells you've been talking about previously?

A. Basically, the wells we talked about previously, the changes in production rate were due primarily to natural decline, you know, what we were talking about in Exhibits 5 and 6. The lower producing rates were due to decline.

There's another way that lower oil rates can be achieved. We can manually reduce the production rates, you know, ourselves, and that --

Q. Has that occurred with these wells?

A. Absolutely.

Q. Why is the Diamond AKI restricted?

A. The Diamond AKI was drilled at an unorthodox location. Under order of the OCD, there is a 30-percent penalty off of the initial potential of that well. The well is only allowed to produce at 70 percent of whatever its initial potential was.

Q. Is this well actually restricted because of that penalty?

A. Absolutely, that's what it was doing. When we completed the well, we placed a sub pump in it, and that sub pump was producing around 800 barrels of oil per day.

And when you look at this, you look at 800 barrels of oil a day, there's a cluster of points around that that are ranging from, say, 27 to just over 30-percent oil cut, and there appears to be a relationship there.

We went into this well, we had a very high producing bottomhole pressure at the time, and we installed a variable-speed drive unit, basically to spin the pump faster and to cause the pump to produce more fluid. We did that, and we increased production rates into the 1100-barrel-a-day range, and we were up at the 32-percent-oil-cut range.

We continued to increase the produced fluid volume to slightly in excess of 1330 barrels a day. Okay, that's produced oil.

At 1330 barrels of oil per day, we were at about 35-percent oil cut. The well was IP'd at 1330 barrels a day. The IP is approximately -- I mean, with the penalty and considering everything, the allowable for the well is around 800 barrels a day. So we took this same variable-speed drive unit, slowed the pump down, and watched what happened as we slowed it down. We slowed it down to around 900 barrels a day, a little over 900 barrels a day, and we were around 30-percent oil cut.

So what happened in this well was, we took it from low rates to much higher rates, back to the middle, and this relationship held almost perfectly throughout this period. It's --

Q. And that relationship is: high producing rates, high oil cut?

A. Absolutely. That's, you know, what I'm here to show today.

Q. What about the Aparejo APA Number 5 well, the second page?

A. This particular instance, instead of installing a variable-speed drive unit, we installed a different size pump. That's another option that you can do. We went from a series 1750 sub pump, which is -- the oil rate's around 50 barrels of oil per day -- to a series 3000 pump, and then we had the regression through there.

And you can see this same type of relationship holds true; at the higher fluid rates, we produce at a higher oil cut. And that's something that's been known in Dagger Draw empirically for many, many years, this is just the data presentation to show what we've known for a while.

Q. Do you have any doubt in this pool that you've produced the wells more efficiently and have higher oil cut if you produce at higher rates?

A. No, sir, I do not have any doubt.

Q. All right. We've talked about oil production. What is the impact of high producing rates on gas production? And you may want to at this time refer to your Exhibit Number 8.

A. Well, you know, I was concerned that maybe at the high rates we would get high GORs. But I refer back to the Diamond Number 1 and --

Q. The same well as in the previous Exhibit, that has a 30-percent penalty?

A. Yes, sir, this is the same well. In fact, Exhibit Number 8 refers to the same two wells that were referred to in Exhibit Number 7. However, Exhibit Number 8 is oil rate on the X axis versus GOR on the Y axis. We were concerned that, you know, the GOR might increase with the increased rates.

However, the opposite is actually what happens here. You can see that around the 800-barrel-a-day rate, except for one data point, we're around the, you know, upper 5000 to 6000 SEF per barrel of oil. When we increased to the 1300 barrels a day, we were in the -- we were below 5000 on our GOR. And we backed it down to 900, and we were back up in the 5000 to 6000 range.

So this particular well shows the relationship that as you increase the drawdown or increase the producing rates, you decrease the GOR, and you again conserve energy in the reservoir.

Q. Mr. Fant, when we look At Exhibit Number 8, you're showing basically fairly recent data; is that not correct?

A. Yeah, this is data -- This again is daily oil rates. You know, each one of these represents one day's of production for that well.

Q. Is this information consistent with the historical data on the pool?

A. Yes, sir, if you refer back to Exhibit -- I want to say 6 --

Q. It's Exhibit 6.

A. -- the right-hand column on this particular exhibit is entitled "GOR Slope". And when you look at the GOR slope, what we're seeing for -- the relationship we're looking for in this case, that's shown by the Diamond, is a negative slope. And when you look at the data here, in excess of 75 percent of the time we see this negative slope.

So again, it's a strong relationship over time, as shown in Exhibit 6, and on an instantaneous basis as shown in Exhibit 8.

Q. In this pool, is it fair to say that in most instances, higher producing rates result in lower GOR?

A. Yes, sir.

Q. Have you studied interference data on the pool to attempt to determine the appropriate number of wells for each proration unit?

A. Yes, sir, I have done an extensive study on interference throughout Dagger Draw.

Q. Both pools?

A. Both pools.

Q. Let's go to Yates Exhibit Number 9. Can you identify that and review it for Mr. Stogner?

A. Yates Exhibit 9 is a set of four plots, there are four plots, that basically I'm trying to familiarize with my methodology for looking for interference between wells. This is an example of interference between two wells, and this is -- you know, that's what -- I'm showing you an example of what I saw.

Q. And your work is not based on pressure tests or interference tests; is that right?

A. No, there isn't enough pressure data to do it. I'm basing my analysis on decline rates, fluid rates and analyzing the decline curves of the wells. And, you know, there is -- I want to say right here, there is some interference between some wells, and that's not necessarily a bad thing. I mean, you -- In order to efficiently develop the field, you must reach some point of minor interference. That must be reached.

But what we're looking at here, the first plot is a plot of oil production for the two wells in concern. The bottom line with the squares is the oil production for the Warren ANW Federal Number 1, and the diamond-shaped ones are for the Thomas AJJ Number 6, and then there's a line that goes up above that with circles on it, and that's the combination of the two.

So it's important to look at what are the wells individually doing, plus what is the sum of the two wells?

Q. Are these wells offsetting each other?

A. These wells are direct 40-acre offsets to each other.

Q. All right. What do these plots show?

A. Well, when you look at the first page, you see that the Warren ANW Number 1 was basically producing along at a moderate decline, at about 110 to 120 barrels a day, in early 1995.

Then in June of 1995, the Thomas 6 was completed, and you can see that the total oil rate for the -- combined jumps way up. The Thomas 6 came in at over 500 barrels of oil per day, and you see that in July of 1996 the slope of this plot, of the Warren's oil production curve, seems to change, almost immediate. That's what we find in Dagger Draw, is that interference is -- If it's going to occur, boy it's almost immediate. And the Thomas 6 has somewhat interfered with the Warren 1. The Warren 1 goes on a new decline rate, and the Thomas 6 establishes its own decline rate.

Now, what's important to note about this is that based upon these declines, we can estimate how much of the reserves in the Thomas 6 are new reserves. And in this particular instance 71 percent of the oil produced from the Thomas 6 would not have been recovered by the Warren 1.

So yes, there is some interference, but it's not totally redundancy. And it's important to note that if the Thomas 6 had not been drilled, that the Warren 1 -- then the Thomas 6 would not have been able to recover that 71 percent of that oil. That would have been wasted.

Q. Now, in comparing the effect of the Thomas well on the Warren well --

A. Uh-huh.

Q. -- did you do that just for the purpose of this hearing today?

A. Oh, no, this was a study that I did back in January and February of this year, at the request of our management. We had a concern --

Q. And how many wells did you study when you did this?

A. Every well, basically, in Dagger Draw, was included in this study, that I could -- that I had data for.

Q. Let's go to Yates Exhibit Number 10. Could you identify and review that, please?

A. Okay, Exhibit Number 10 is -- Basically what we're looking at here is Sections 8, 9, 16, 20, 21, 28 and 29. This is the area -- the primary area of new development.

Q. Is this where the proration units are that are overproduced, most of them?

A. Oh, yes, sir. Our over- -- The proration units that are overproduced for Yates Petroleum are located in Sections 21, 28 and 29. The only other overproduced proration unit in North Dagger Draw would be in Section 27, immediately to the east of Section 28.

Q. What does this exhibit show?

A. Basically, what I'm illustrating here is, in my study, when you look at this area -- and this is the area where the new development is going on -- each one of these lines represents a place where I found some interference between wells.

There are five solid lines on this page, and one dashed line. That one dashed line represents one that we don't -- I don't have enough data to confirm that there's interference, but that's one that I suspect that there is. So I wanted to, you know, be up front and go ahead and put that one in here.

Q. All right. You have six examples of

interference?

A. Six cases where I have found it, yes.

Q. And you have analyzed the potential for interference between really all of the wells shown on this plot, as well as elsewhere in the pool?

A. Yes, every well -- Basically we looked at every well and its direct offset, and if you evaluate this thing, how many 40-acre offsets there are -- You know, how many potential lines could there be on this page?

Q. And how many could there be?

A. There could be 137.

Q. And you --

A. That's how many cases I evaluated just on this piece of paper, and there's only six out of 137.

Q. So what percent of the cases in this area are you finding signs of some interference?

A. Less than five percent, less than five percent of the time does there appear to be -- in this area of new development, does there appear to be any interference between a well and its offset wells.

Q. When you look at these, are you able to calculate the extent of the interference?

A. Yes, that's what I was speaking of earlier with regards to Exhibit Number 9. In that case, only 29 percent of the reserves were affected.

It's very important to note that the average throughout -- in these six -- well, actually, basically the average in this area, when interference was seen, is around 20 percent. So what I'm saying there is that when interference does occur, only about 20 percent of the reserves are affected.

And when you look at the fact that interference only occurs five percent of the time or less, and when it does occur, you're only looking at about 20 percent, you have to multiply those two together to look at the statistical effect of interference in this area, and it's less than one percent. The effect of interference in this area is less than one percent of the reserves.

Q. If we look at the Thomas well, 71 percent of the production was new production?

A. Absolutely.

Q. If we look at the other wells where there was interference, do they remain economic on an incremental basis?

A. Yes, the 40-acre locations in this area are economic, they are tremendous money-making opportunities on an incremental basis.

In fact, it's important -- One of the things I wanted to bring back about Exhibit Number 9 is that there's been statements people make that when you drill the 40-acre wells after drilling the 80-acre wells, when you infill on 40s, that those wells aren't any good.

The Thomas 6 was a 40-acre infill location, basically, and it's better than any of its offsets. It's the best well in the area, and it was one of the last wells drilled. You know, that -- Again, that just supports that 40 acres is the way they need to be developed.

Q. And that's what you're recommending for both the North and South Dagger Draw Pools?

A. Yes, sir.

Q. Let's go to Exhibit Number 11, and I would ask you to refer to this exhibit and explain why it is Yates is seeking a 4000-barrel-of-oil-per-day depth bracket allowable in North Dagger Draw.

A. Exhibit Number 11 is an oil- and gas-rate plot for one well, the State K Number 3.

In setting this for hearing and to determine what we felt should be asked for in terms of allowables, it was my intention to tie it back to something reality, something relating to the field. I didn't want to just pull a number out of the air; I wanted to get a number that related to the field.

And in the case of the State K Number 3, this well has produced approximately -- it's been above, it's been below, but 900 to 1000 barrels of oil per day for 17 months. Nobody -- You know, if we had come in in early 1995, nobody would have believed us that this well would have produced this long -- this much oil, for this length of time.

Q. If you had four wells on the 160, as you could --

A. Yes, sir.

Q. -- on 40-acre spacing, what allowable would you need to effectively produce that 160 spacing unit in North Dagger Draw?

A. I believe we would need, based upon this, 4000 barrels a day.

Q. And that's the basis for the request?

A. That is the basis for the request.

Q. What about South Dagger Draw?

A. South Dagger Draw, basically the proration units are not 160s, they're 320s; you could have eight wells on a proration unit.

We've already seen in the Diamond Number 1 that there are wells capable of in excess of 1000 barrels a day. That's where that basically came up, to keep the two pools on a par with each other in the oil production, which I believe has been a historical goal that would require that South Dagger Draw be 8000 barrels a day; that's the basis for the numbers in the Application.

Q. Is the State K Number 3 overproduced?

A. Yes, sir.

Q. If we take a well like the State K Number 3 and we try and get it back in line under current allowable limits, could Yates not just shut the well in for a period of time and then put it back on production and then shut it in again, so you could maintain high rates when producing, and yet reduce the ultimate withdrawal or the total withdrawal from that well?

A. That is something that was proposed to us at some of our meetings with the OCD, that we could simply shut it in for a day and produce it for a day, or shut it in for a couple of days and produce it for a couple of days. And that's a valid thing that needed to be looked at, and so basically I went back and studied it.

It was a concern of mine that the first time you go through that cycle, you get the effects of producing at the high rates. But I was concerned that the second, third, fourth, fifth, sixth, seventh and eighth time through this cycle, that the effects of doing that might become diminished.

And in fact, when we met with Conoco, I voiced these concerns. We met with several of the operators in the pool to discuss this option, and --

Q. Why don't we go to your Exhibit 13 --

A. Okay.

Q. -- and take a look at the effects of cyclic versus continuous production of these wells?

A. When you look at this, what I did was, I said --

MR. CARR: There's no 12. There is no Exhibit 12 --

MR. KELLAHIN: All right.

MR. CARR: -- so we go to Exhibit 13.

MR. KELLAHIN: All right, I'm with you.

MR. CARR: Okay.

THE WITNESS: When we're looking at this and -- What I did, if you have a well that's capable of 1000 barrels a day and you only produce it for half the time, then your effective rate is 500 barrels of oil per day. And so, you know, that's kind of using the State K 3 as an example.

So what I looked at here, what I wanted to look at was, what are the effects in the reservoir of using this production method? And Exhibit 13 is two sets of plots, and on the X axis we have time on production. And on the Y axis is something I call cyclic production drawdown, and what that is is, I'm comparing the drawdown with this cyclic production method, versus the drawdown at just putting it at half the rate. In other words, when I'm producing in the cyclic method, when the well's on, it's on at 1000 barrels a day. The standard 100 percent -- a line through the 100 percent would be the 500-barrel-a-day rate. Okay?

And what it shows is -- And I'm showing this for three depths in the reservoir. The small dashes are 50 feet in the reservoir, the solid line is what's happening 100 feet in the reservoir, and the longer dash is 150 feet in the reservoir.

And basically what it shows is, this top plot is the well producing for a day and being shut in for a day, producing for a day, shut in for a day, and that's what creates these cycles.

The first time through the cycle, zero to one, we see we're at 200 percent of what the 500-barrel-a-day, which is what it should be. We're producing at 1000 barrels a day that first day. The reservoir doesn't know we're going to shut it in. We're producing at 1000 barrels a day, which is twice the drawdown you would see at 500 barrels a day.

But each one of these cycles, what you have to look at is what happens to the peak as we go through the cycle. And when you go to the -- what the peak drawdown is through the second cycle -- It's this peak right here at the end of -- right here at three days. And what you see is, you're a little less than 50-percent incremental from going to this method. After five days you're under 40 percent. And you get out here to nine days, you're under 30 percent for the 50 feet in the reservoir.

Now, 50 feet in the reservoir is not even off the well pad in most instances. We're not talking -- at 50 feet in the reservoir, you're talking less than one percent of the reservoir.

When you get -- You know, you can see that when you're looking at 100 feet in the reservoir, after you go through a few cycles, you're down below -- you know, at the end we're down around just over 10 percent incremental effect. And at 150 feet into the reservoir, after a few cycles, we're down below 10 percent.

Basically over time, using this method of turning it on, turning it off, turning it on, turning it off, you would -- the effects would wear off, and fairly rapidly. We're talking about 10 days here, and we essentially have no more effects of it.

So what this says is that if we use this production method, initially there should be really no change in the oil cut. But as time goes on, it should go down.

Q. (By Mr. Carr) And that's because the peak in the drawdown is less during each subsequent cycle?

A. Absolutely.

Q. And is that a less efficient way to recover the oil --

A. Yes, sir.

Q. -- from this reservoir?

A. Yes, sir.

Q. Is it actually a wasteful process, compared to simply producing the well on a continuous basis at a higher rate?

A. Yes, sir, it will waste oil in the life of the well.

The second plot is the same type of plot on a 12-hour cycle, 12 hours on and 12 hours off.

This is the production method we had to use to restrict our wells that are out in the field, because we don't have variable-speed drives for all of our wells. We had to go out -- Well, there's time clocks on these wells, and basically the time clocks, they're either on -- they're on for 12 hours, they're off for 12 hours. So basically what this second -- And that's an operational constraint of how we have to run the wells. And what you see on this second page is actually what was done, basically, to the wells. Now, it's not exactly 50-50, you know, 12 hours on and 12 hours off. It was -- The wells were adjusted to make the allowable properly.

Q. Let's go to your Exhibit Number 14. What is that?

A. Okay, well, if I may --

Q. Okay.

A. -- I just made a statement that using the production method we're using, we should see essentially no change for a while, and then a reduction in the oil cut.

And what you see on Exhibit 14 is a plot of the oil cut versus each -- versus time for these wells, since we've changed the production style, since we have started restricting them. And you could see that it kind of bounces around in the early time frames. But again, running a regression through the line, it basically went flat for a while, and then it started down here in the late time.

This data is basically saying, what we were anticipating from -- would happen based upon Exhibit 13, Exhibit 14 is saying that's actually happening in the reservoir, in the -- or in the field. This is what's happened. We are seeing -- you know, the oil cuts are beginning to come down. We were around 60-percent oil cut prior to changing it. Now we're down closer to 58-percent oil cut.

And I expect that to continue to go down.

Q. So basically, the -- this exhibit shows that the points were pretty much scattered to begin with, but they do pull into line as you get farther along in the --

A. And that --

Q. -- as you've carried it, and there is a definite decline in the oil cut?

A. Yes.

Q. Mr. Fant, what conclusions have you reached from your engineering work on this reservoir?

A. Basically all this -- you know, what I've presented here today is that the higher producing rates, i.e., higher drawdowns, give you a higher oil cut and a lower GOR, and both of those are -- help you prevent waste.

Q. Why is that?

A. Basically, we're only going to get a certain amount of fluid out of this reservoir, and if we're taking reservoir energy out in the form of water and gas and not getting the oil that we could, at the end of the life of the field, there will be oil left in the ground. It's an inefficient production method.

It's a standard principle of petroleum engineering that you want to leave as much of the gas and water in there for as long as you can. We'll get the gas later. But the oil will be left behind, there will be some oil left behind.

Q. Mr. Fant, what if the operators in the pool are required to make up current overproduction? What impact will that have on the waste issue?

A. Well, essentially, you know, some of the wells might have to be shut in. Basically, wells would have to be restricted or shut in, which would lower the ultimate recovery.

And it could really impact us if -- Any time you shut in a well, you run the risk of not getting it back. Any time you shut it in for a long period of time, you run a significant risk of that well not producing as well when you bring it back on line.

Q. In your opinion, would cancellation of overproduction in these pools impair correlative rights?

A. No, sir, basically the drainage data I was showing you, interference data, was to show that basically 40 acres, especially in this area, this area where we have the new development, where these rules will basically impact the reservoir, 40 acres is proper. There's essentially one percent or less interference between them. And so basically they're -- correlative rights is not an issue at this point. 40 acres is proper, and the wells are not affecting really more than 40 acres.

Q. Do you see any real advantage being gained by an operator on an offsetting property if they're able to produce at higher rates?

A. No.

Q. In your opinion, will approval of these

Applications be in the best interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes, sir.

Q. Were Exhibits 4 through 14, with the exception of 12, were they prepared by you?

A. Yes, sir, they were.

MR. CARR: Mr. Stogner, at this time we would move the admission into evidence of Yates Petroleum Corporation Exhibits 4 through 11, 13 and 14.

EXAMINER STOGNER: Exhibits 4 through 11, Exhibits 13 and 14, if there are no objections --

MR. KELLAHIN: No objection.

EXAMINER STOGNER: -- will be admitted into evidence.

MR. CARR: And that concludes my direct examination of Mr. Fant.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin, do you need a few minutes to prepare your cross-examination?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Okay, your witness.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Fant, who is the individual at Yates that is responsible for monitoring the production in North Dagger Draw?

A. I guess I'm not sure -- Monitoring production with regards to --

Q. -- determining how much that well has produced on a daily basis?

A. On a daily basis, that would be the pumper who goes out and determines what they produce.

Q. And who does he report to?

A. He would report to the production superintendent -- or no, excuse me, probably the production foreman, is who he would report to.

Q. Who's Mr. Brian Collins?

A. Mr. Brian Collins is the operations manager.

Q. All right. The operations manager, then, is ultimately going to be responsible in Yates for monitoring the production in both North Dagger Draw and South Dagger Draw; is that not true?

A. It would move to his office, yes, sir.

Q. All right. And he is the person in Yates that has the responsibility to tell the pumper or the field personnel to either produce the well more or restrict that production?

A. Yes, sir.

Q. Those would be his decisions?

A. I would be -- I would think that's a fair characterization; those are his decisions.

Q. All right. When did Mr. Brian Collins become responsible for the Yates production in both those pools?

A. Basically, that would have been the first week in March, the week that the OCD came and spoke with us.

Q. This is the first week of March of 1996?

A. 1996, this year, yes, sir.

Q. All right. Who was Mr. Collins' predecessor in that particular capacity?

A. That would have been Mike Slater.

Q. Mike Slater?

A. Yes, sir.

Q. Do you know how long Mr. Slater had that responsibility for Yates before he was replaced by Mr. Collins?

A. I don't know Mike's original time that he was in that position, no.

Q. Would Mr. Slater's responsibility for monitoring production in both of these pools have been for a period of time sufficient to cover the overproduction in North Dagger Draw before he was replaced by Mr. Collins?

A. Yes.

Q. All right. So those two individuals, then, would have monitored production?

A. Yes, basically, I believe so.

Q. Why was Mr. Slater replaced by Mr. Collins?

A. Mr. Slater retired.

Q. All right. And who do you report to, sir?

A. I report to Pinson McWhorter.

Q. All right. Would Mr. Slater and then Mr. Collins be the representatives at Yates who would be responsible for compliance with the production limitations in North Dagger Draw?

A. I don't know that -- You know, I guess I'm kind of confused on that. They are the operations managers. As to, you know, from a legal standpoint, whether they are not -- you know, I really don't know. But basically Brian Collins is now the operations manager, and Mike Slater was. They would have the ability to make those decisions, I would think.

Q. You described for us your knowledge of the production limitations that are currently established by Division rules for both North and South Dagger Draw.

A. Yes, sir.

Q. All right. Is it fair to assume that Mr. Slater and then Mr. Collins would know those production limitations as well?

A. Yes, sir.

Q. And did you and those individuals rely upon

ONGARD to give you production data for your wells?

A. I do not rely on it. I do not know what they rely on. I would think not.

Q. And in fact, Yates relies upon its own production information for those wells?

A. Yes, sir.

Q. And that's the information you get from your pumper and field personnel, reported to Mr. Collins and Mr. Slater?

A. Yes, sir.

Q. All right. Who in Yates made the decision to overproduce these particular wells in North Dagger Draw?

A. That would have been a decision made at a level other than mine, and I was not privy to that decision being consciously made by anybody.

Q. Do you know when that decision was made?

A. No, sir.

Q. All right. When is the first date of overproduction in North Dagger Draw for any of your wells or spacing units?

A. I know that there was a spacing unit back in the early 1990s that was overproduced for a while, and we brought that proration unit back into line. But now I can't -- I don't believe I can accurately assess that.

Q. You focused your attention on a portion of North

Dagger Draw that has an area where there is new wells of a vintage dating from after -- about March and April of 1995. Am I about correct on the time frame?

A. I would say it actually goes back to around August of 1994.

Q. All right, August of 1994, you start picking up some wells in this new area in North Dagger Draw that I think you characterized as being portions of Sections 21, the west half of 27, 28 and 29?

A. Yes.

Q. All right. The operators in that area are Yates and Nearburg, are they not?

A. And Conoco.

Q. Okay. Is there an explanation as to why the area of overproduction for those spacing units is concentrated within that geographic area?

A. I believe it relates to reservoir quality in the area. The reservoir quality is far superior to many other places in the reservoir.

Q. Did the initiation of overproduction in that area have anything to do with competition between Yates and other operators for withdrawal of oil from that area of the pool?

A. I don't believe so.

Q. When did you commence your study with regards to examining the phenomenon that you have seen where the early-time performance of these wells in this area exhibits an effect where at higher withdrawal rates you have a higher oil cut?

A. Well, that's really hard to say, because as I told the Commission earlier, this is a -- this is something that people have talked about for years, so I --

Q. I didn't make my question clear.

When did you first commence your formal investigation of the presentation you've just given us this morning?

A. Of this particular presentation --

Q. Yes, sir.

A. -- I began it a few -- before -- around the beginning -- I'd say around the beginning of March would be the time frame.

Q. All right. Do you know whether or not it was the Oil Conservation Division that brought to Yates's attention the overproduction that was occurring in this new development area of North Dagger Draw?

A. I know that the OCD brought it to our attention.

Q. All right. And in response to that, then, did you then commence your study that you've brought us today?

A. I would guess that's a fair characterization, yes.

Q. The area of overproduction within portions of these four sections --
A. Uh-huh.
Q. -- the first well within that area that exhibited this phenomenon where early-time performance shows at higher rates a higher oil cut occurred when, sir?
A. I guess I'm not exactly -- I never looked to say, okay, which well, when did this first occur? I didn't study it from that standpoint.
Q. All right. As we sit here this morning, do you have a number to tell us what the total cumulative overproduction Yates has accumulated in North Dagger Draw for its spacing units? Do you know what that number is?
A. I do not have a specific number, no.
Q. Do you have that number by spacing unit?
A. Not with me, no. And it would have to be calculated, because we have changed our practices, and some days the well -- many of these days since then, the wells have been under allowable.
Q. What is Yates's explanation for the overproduction of the allowable limitations in North Dagger Draw?
A. I am not in a position to offer an explanation for that.
Q. All right. Who would be the person responsible

at Yates that could provide us with that explanation?

A. Well, unfortunately I believe he retired from Yates.

Q. Who is the person at Yates responsible for deciding to request an oil allowable in North Dagger Draw of 4000 barrels a day?

A. I don't know that there would be a -- If you're specifically saying who recommended 4000 barrels a day, that would be myself --

Q. All right.

A. -- based upon the technical information.

Q. And the basis for the 8000 barrels of oil a day for a 320 spacing unit in South Dagger Draw is also your recommendation?

A. Yes, sir.

Q. The recommendation for South Dagger Draw is simply a multiplication of the allowable from North Dagger Draw; is that not true?

A. That was the basis for it, to keep the two on par with each other, yes.

Q. When we look at South Dagger Draw, do you have available to you now technical data that would support the 8000 barrels of oil a day on a 320 spacing unit in the South Dagger Draw Pool?

A. I've already stated that the Diamond is a well capable of in excess of 1000 barrels a day. So if you develop it on 40s, the Diamond, which is in South Dagger Draw, that well would be -- if you developed those proration units fully, then it would -- you would come to -- and if you produce those wells at 1000 barrels a day, that would be eight wells, 1000 barrels a day, 8000 barrels a day.

Q. All right, let me make sure I understand the assumption. When you look in Section 20 -- Township 20 South, Range 24 East, you're looking at Section 34, and you find down in Unit Letter M, I believe, the Diamond well, in the southeast of the southwest of 34, that's the one you're talking about?

EXAMINER STOGNER: Excuse me, where is that again?

MR. KELLAHIN: We're in South Dagger Draw. We're in 20 South, 24 East, Section 34.

THE WITNESS: Uh-huh.

Q. (By Mr. Kellahin) It is the section just above the irregular short township in there, or sections in there, and then we're looking at the southeast-southwest of 34, and that's the Diamond well, is it not, Mr. Fant?

A. Yes.

Q. All right. And that's the well that was the subject of a penalty presentation here before the Division, and that well resulted in having a penalty, a production penalty, of about 30 percent, if I remember right?

A. Absolutely.

Q. All right, that is the single example that you have in South Dagger Draw by which, then, you have calculated that if the Diamond well, at about 1000 barrels -- or plus, I think it's at 1300 a day?

A. Its maximum rate, yeah.

Q. Maximum rate was 1300 a day, and if you multiply that by -- what are you looking for? -- eight wells in a 320 spacing unit, then that would be your basis of your argument for an 8000-barrel-a-day oil allowable in that pool?

A. That is one of the examples; that's the only one I have presented specifically. There are other wells in South Dagger Draw that have produced well in excess of 1000 -- that have produced in excess of 1000 barrels a day.

Q. I understand that. I'm forecasting for future in terms of a rule change, whether there are any other wells in the pool that have the capacity for an existing spacing unit to produce more than 1400 current oil allowable.

A. There's currently wells overproduced in -- There are proration units currently overproduced in South Dagger. So obviously there is a capacity to do it, because there are proration units that are overproduced.

Q. If we increase the oil rate in South Dagger Draw to 8000 a day, and the gas-oil ratio stays at 7000, the GOR stays at 7000, we would have the gas allowable for that pool in a spacing unit of 56 million a day, 56 million MCF a day, right?

A. Well, 56 million standard cubic feet per day, yes.

Q. Yes. Do you have an opinion as to whether or not there is any spacing unit that has the capacity to reach that gas allowable in that pool?

A. Not at this point, no, sir, I don't.

Q. In your opinion, would that be an excess gas allowable in South Dagger Draw?

A. If the objective is the maximization of liquid hydrocarbon recovery, I would say no.

Q. Is it not reasonable to attempt to conserve the gas energy in the reservoir in South Dagger Draw, in order to have that drive mechanism available to maximize oil recovery?

A. Absolutely, and that's what we've presented here, that as you produce at the high rates, you have lower GORs, so you are maximizing energy when you do that.

Q. You haven't told me the gas effect, though, with regards to that test. My question is, do we have a spacing unit in South Dagger Draw at your optimum rate that needs the 56-million-MCF-a-day gas allowable?

A. I do not know that the 56 million would be needed.

Q. All right --

A. I'm simply saying, the oil rates are needed to maximize oil recovery.

Q. All right. What is your recommendation on the gas rate?

A. I am not presenting a recommendation on the gas rate.

Q. All right. When we look at North Dagger Draw and South Dagger Draw, there is no active water drive in either reservoir; is that not true?

A. I believe that the -- that water drive is not a significant -- any significant drive mechanism in these reservoirs.

Q. All right. We simply have a finite volume of fluids, then, that are going to be produced out of the reservoir?

A. I believe so.

Q. And it's going to be produced on some depletion -- gas-expansion depletion method; is that not right?

A. That is what the production history suggests.

Q. All right. Is it not true that in a reservoir of this type where that is the depletion mechanism, that the reservoir is not sensitive to the rate of withdrawal?

A. That is a basic theory promoted for homogeneous, single-porosity systems. I do not believe that can be held true for dual-porosity systems such as we have in Dagger Draw.

Q. All right, let's make sure that we set up the question so that you can tell me your opinion.

If you're looking at a homogeneous reservoir where the depletion mechanism is gas expansion, then it would not be rate-sensitive; is that not true?

A. I believe I've testified to that before the Commission before.

Q. All right. And so what you have by increasing the rate of withdrawal is not an increase in ultimate recovery of hydrocarbons; you simply accelerate the rate of withdrawal?

A. Are you speaking in the case of a homogeneous system?

Q. Yes, sir.

A. In the case of a homogeneous system, I would say that that is an accurate statement.

Q. All right. When we get into North Dagger Draw, you have a theory of a dual-porosity system, where you have oil stored in a matrix and then oil stored in a vuggy system or a larger-porosity system, you've got a dual-porosity system under your concept?

A. At least a dual-porosity system, I would say at this point.

Q. All right. And you're arguing that these new wells at the higher rate allow you to gain some advantage in terms of how you deplete the dual-porosity system?

A. That's what the data suggests.

Q. All right. When we look at the data that justifies, in your opinion, the increase, the data is concentrated within the area described as Sections 21, west half of 27, 28 and 29. That's the data pool that you've examined, is it not, sir?

A. No, sir, I believe if you look at Exhibit 6, I've examined every well in Dagger Draw.

Q. I understand. When you look at the 17 examples, if I remember right from the earlier exhibit, you're looking at the early-time performance of 17 wells, and those are concentrated within the area that I've described?

A. Well, those 17 particular wells, that's the lifetime performance of those wells thus far. It's not just early time; that's the lifetime, on those particular wells, that's monthly production data.

And those wells that I have -- Those are the wells that I have given examples of, but those are simply primarily intended to be examples to show you what I was analyzing in the numbers that are presented in Exhibit 6. And Exhibit 6 was intended to show that although those are some of the ones that I had presented individual plots on, I have studied all of the wells.

And that was my intention, to make it a fieldwide study, not just that area. The reason those wells -- One of the reasons those wells happened to come from that primary area is because that's an area that has some of the best wells in the field, basically.

Q. Let's look at Exhibit 4, then.

A. 4, okay, that's the first one I gave you.

Q. Yes, sir. Am I correct in understanding it was your testimony that the swabbing oil cuts that you obtained in these wells that you described are always going to be lower than the pumping oil cut?

A. I would not say the word "always", but almost always.

Q. Okay. When I look at Exhibit 4, then, I'm looking only at data that describes the swabbing oil cut in the second month of production with regards to the 58 wells shown on this summary. I'm reading the caption and trying to figure out if that's --

A. Swabbing oil cut versus second-month producing oil cut.

Q. Yes, sir. Did I say that right?

A. Well, I may have heard it wrong, I apologize.

Q. Let me do it again.

A. Okay.

Q. When I look at Exhibit 4, am I looking at, for the 58 wells, the swabbing oil cut in the second month of production for those wells?

A. No. The swabbing oil cut is the oil cut immediately after basically perforating and trying to do some stimulation and taking out the load water.

See, that's -- You know, we can't do it for all the wells; we can only do it for some of the wells. We have to be able to have load recovery.

Q. Well, when I look at the horizontal axis I've got a percentage here. It says Average Swabbing Oil Cut for the Well.

A. Yeah.

Q. Is that taken out of the second month?

A. No, you only swab the well when you're completing it --

Q. All right.

A. -- I mean, while the pulling unit -- while the completion unit is sitting over the well. I mean, that's basically the earliest production data we have for the well.

Q. All right. What is your argument for using the swabbing oil cut?

A. Quite simply, when you swab a well, you are very limited in how much rate you can achieve, in other words, how much average drawdown you can put on the reservoir.

When you're swabbing one of these wells, you're swabbing at a produced fluid rate of about 500 barrels a day. That's the key there, that's a minimal drawdown. Whereas -- You know, 500 barrels a day, of fluid a day -- We're not talking oil, we're talking fluid a day, that's oil and water. And when you're swabbing at those rates, that's a very minimal drawdown on Dagger Draw reservoir. 500 barrels of fluid a day may sound like a lot, but for wells in Dagger Draw, that's not a very significant -- that probably represents, in general, less than a 25-percent drawdown.

Q. Here's what I'm trying to understand. I'm trying to understand the fact that in the early few months of these wells, as I understand your testimony, they characterized wide fluctuations in performance, which I would equate to be an unstabilized wellbore condition.

A. Oh, I don't believe so. That would be another reason for using the second month. You have achieved -- Your wellbore conditions have stabilized in the second month. When you're moving fluids of this volume, your wellbore conditions stabilize very rapidly.

Q. All right. So your argument is that in the second month we now have a stabilized wellbore condition in these wells?

A. We have -- that is -- that is indicative of the early -- before -- hopefully before depletion sets in on the well.

Q. All right. In all these examples, then, in the second month, have these wells been fully drawn down where you're having the maximum capacity in the well to move reservoir fluids in that well?

A. These wells in the second month of production are producing at their -- at the maximum capacity of the pump. Sometimes the reservoir will put more fluid out than the pump can handle, and you're limited there by the pump capacity.

Q. All right, are those wells all pumped off, then, so that you do not have a limitation in the capacity of the reservoir to put fluids in the wellbore?

A. No, these -- most -- Many of these wells would not be absolutely pumped off --

Q. Okay.

A. -- and that just further supports my position.

Q. All right. I noticed you have plotted the data in a summary fashion. Do you have available for these wells the actual volumes of oil, gas and water on a daily basis?

A. Are you talking about Exhibit 4?

Q. Yes, sir, we're still on Exhibit Number 4.

A. The data certainly exists. It is -- the producing rates -- I have the data in a spreadsheet for the producing volumes, produced oil and produced water, and then the swabbing oil cut. Those were simply calculated.

Q. Yes, sir. I want to look at the raw data by which we generate this display. And my question for you, sir, is that data available in a public source so that my reservoir engineer can make his own calculation? Or is that something --

A. The second-month producing data is certainly available. I mean, that's just straight out of *Dwight's* or ONGARD or whatever.

Q. The data on all these spacing units that have wells that are overproduced, is all that data available in a fashion where my engineer can look at it in terms of volumes produced on a daily basis?

A. Absolutely. We gave him that data --

Q. All right, so it's --

A. -- that provided them with -- up through February. After our meeting last week they wanted to do a data exchange, and I gave them the data up through February, because I did not have the data for March as of that time.

Q. All right. Before we leave Exhibit 4, then, am I correct in understanding that you've excluded the first month's production because in that first month's production we've got some unreliable information because the well is not stabilized?

A. I wouldn't say it's because the well is not stabilized. I believe it's because when you're swabbing on a well, okay, you're going to produce oil into a tank, okay? You're going to sell that oil, and that oil is going to be reported to the State.

The water that goes into those tanks is going to be drawn off by a transport and taken to maybe a saltwater disposal system. But the water you produce on completion is not going -- may not be reported to the State. I mean, it's not huge volumes, but because of how that stuff is handled, that water production may not be reported.

So I was concerned -- And what that would have done was made -- that would have made this relationship look even stronger, and I wanted to look at what the real data said.

Q. All right. When we look at Exhibit 5 --

A. Okay.

Q. -- you're demonstrating an oil cut versus an oil rate for the wells shown on Exhibit 5, and each one is

tabulated individually?
A. Yes, sir.
Q. All right. When I look at the top one, so I understand your method, the Aparejo Com 3 --
A. Yes.
Q. -- when I start with the first data point, what is the time component that we're dealing with here?
A. Which data point are you speaking of?
Q. The first data point that's shown when we move along the horizontal curve at the oil rate, and I've got an oil rate of something -- oh, about 350 barrels a day, I guess. At the starting point of the curve.
A. Okay. My estimate, that would -- I cannot specifically state that for this well, but it is my estimate that that would be the most recent data.
Q. Yes, sir, and approximately what is the date?
A. Oh, this would be -- let me see, this would be -- That would have been February's data --
Q. All right.
A. -- because --
Q. The time frame is what I'm trying to establish, Mr. Fant. For these wells, I'm looking at a time frame of how much production?
A. Each one of these dots represents one month's worth of data.

Q. All right. And for example, this is probably what -- on this well is approximately what month?

A. Well, the most recent on these -- any of these plots would have been February's data, because that's what is in my database to generate these curves.

Q. All right. So when you look at the last data point on the far right of this plot, is that the February of 1995 date?

A. That would be -- I don't know why it would be February of 1995. It would most likely be the initial completion of the well.

Q. I'm confusing you and myself. I'm trying to understand, when I look at this plot, and I've got rate versus oil cut --

A. Uh-huh.

Q. -- what's the time frame in which this took place?

A. This is the life of the well.

Q. All right. So -- Is the data available in a public source that I can go and compare these data points, and I can know the actual volumes being produced on that day and have a time frame with which this is accomplished?

A. Absolutely, I've given them that data. I've given them the incremental data between what the public sources have and up to what I've used here, the October --

Q. All right.

A. -- it would basically be, I think, October-to-February data.

Q. And so we now have the data by which we can determine the actual volumes that are shown on your curve here, when we look at Exhibit 5?

A. Yes. In fact, that can be generated straight from the curves.

Q. All right. Explain to me in Exhibit 5 what causes you to conclude that this phenomenon is nothing more than simply rate acceleration. How is this going to get us more ultimate oil?

A. It's not just this exhibit.

Q. Okay.

A. It's the knowledge that occurs over time. This shows that it occurs over time, and it's the rest of the exhibits that show that it will occur on an instantaneous basis if we slow the well down.

And again, if we take excess water out of this reservoir, we're going to leave other fluids behind.

Q. You have a display that shows some known interference. I think it was Exhibit 10 that you presented to us. We were looking at an area that included the area of overproduction, and then north you looked at the Warren-Thomas relationship.

A. Yes.

Q. Do you have the data to show for Exhibit 10 what is occurring in the west half of Section 27, which are the two Nearburg spacing units that also have exceeded their oil-allowable limits?

A. I did not have enough data to present those. Those wells are actually quite far from our well -- from our wells. And so I do not -- I do not have that data prepared.

Q. You've observed interference effects in North Dagger Draw, and here's an illustration on Exhibit 10 of that interference effect.

Am I correct in understanding your argument that this is okay because you think 40 acres is the proper well density for North Dagger Draw?

A. What I'm saying in this instance is that if the Thomas 6 had not been drilled, 71 percent of the reserves that come out of that well would never have been recovered by any well. They would have been left in the ground.

Q. We're going to get to that point in a minute. My first question is, for you, when we look at the argument of interference, you're contending that the well density of 40 acres per well is an appropriate well density?

A. Yes.

Q. All right. If the proper well density is 80 acres, then is there still a basis for increasing the oil allowable?

A. Certainly.

Q. All right.

A. State K 3 obviously shows that wells are capable of in excess of 700 barrels a day, and if you -- and if 80 acres -- if it were, even if 80 acres were, but I don't believe it is, then you would need at minimum 2000 barrels a day to properly produce that spacing unit.

Q. If you look at Exhibit 10, then the State K 3 is in Section 28. It's the well in the northeast of the southwest of the Section 28?

A. Yes, sir.

Q. All right. And what's the rate on that well?

A. Well, right now that well is producing at just right around 700 barrels a day.

Q. If it's unrestricted, what is its capacity?

A. It's about 1000 barrels a day.

Q. All right. When you look at the area for which it's competing in the reservoir with other wells, it in fact has a substantial area where it has no direct competition?

A. In one direction. But in the other direction it has multiple wells that it would be in direct competition.

Q. I see no 40-acre offset to the west, to the south or to the southwest in regard to that.

A. That's right, but they are to the east, north, northwest and southwest.

Q. When that well was drilled, did it encounter original reservoir pressure; do you know?

A. It depends on what you define as original reservoir pressure. It was about -- a little over --

Q. Oh, give or take 13 -- 3100 --

A. No, it was about 2000 p.s.i.

Q. All right. Am I correct in remembering that the original reservoir pressure in North Dagger Draw is about 3100 pounds, give or take?

A. I've never seen it reported at 3100. I've seen some wells that have reported DSTs 2900.

Q. All right. What was the pressure on the State K 3?

A. It was about 2100, 2200 p.s.i.

Q. And what does that indicate to you?

A. That indicates that it was 2100, 2200 p.s.i., that --

Q. It's therefore partially depleted when it was initially produced?

A. I don't believe that can be absolutely drawn in this case.

Q. Well, how do you explain the pressure differential of 800 or 900 pounds?

A. I am not absolutely convinced that that other well and this well are hydraulically connected. In fact, the data suggests that they're not hydraulically connected.

Q. If we have a reservoir with limited volumes to produce out of that reservoir, and it's occurring by pressure depletion, and this well comes in at less than original reservoir pressure, what happened to the pressure?

A. We don't know what original pressure was right there. We don't have that measurement. My data has shown that that reservoir is compartmentalized, and therefore you can't absolutely make that statement.

Q. Do you have pressure data for the wells drilled in Sections 21, 28 and 29?

A. 21, 28 -- We would have some pressure data, yes.

Q. Have you examined that as a reservoir engineer to see if there's a pressure relationship with what are happening in these wells?

A. I've not examined it in relation to this study --

Q. Okay.

A. -- no.

Q. That has not yet been done?

A. No.

Q. All right. What kind of pressure data do you have?

A. Basically, if we have any pressure data, there's a little bit on DSTs, and that's about it.

We do have one monitor well in the field.

Q. A monitor well?

A. Yes.

Q. What do you mean by that, sir?

A. Old well -- Well, it was a poor well, went uneconomic. They wanted us to plug it, we wanted to keep it. So we temporarily abandoned it for purposes of monitoring.

Q. Do you monitor it for pressure?

A. Yes, sir.

Q. And where is that well located, sir?

A. I'd have to refer to -- go back to Exhibit 1 to make sure -- It's in Section 20, the Ross EG Federal Number 7.

Q. All right.

A. It would be the southeast of the northwest of 20.

Q. I don't want to mischaracterize your position on pressure, Mr. Fant. Is there a consequence and importance to this reservoir with regards to pressure and the decline of pressure?

A. I believe that the decline in pressure causes this phenomenon that we're seeing here, yes.

Q. What phenomenon?

A. The phenomenon that you -- as pressure declines, your drawdowns decline, your producing rates decline, and your oil cut goes down.

Q. All right, sir. When I look at that over the life of the production of the pool, where am I to achieve the best advantage for producing the greatest amount of oil? Is it going to be when the pressure in the reservoir is less, or early in the life of the reservoir, when the pressure is higher?

A. The only times where it's really going to have a major effect is in the early life of the wells, because in the early life of the wells, under the current rules, the wells have to be restricted.

When the pressure declines such that the wells go on decline and you're on decline, there's nothing you can do at it. You produce them at the highest drawdown. When the wells are below 700 barrels a day, there's nothing that can really be done about it; you produce the wells as fast as you can.

But what I'm talking about is what occurs above that point, the waste that we would cause by restricting wells capable of in excess of what the current allowables allow.

Q. Well, let's identify the waste issue. Have you established a production decline of any of these wells within the overproduction area? It's too early, isn't it?

A. No, some of the wells -- Some of the wells do have decline, because you've got to remember, some of these proration units, it's not necessarily a well that's overproduced but the proration unit that's overproduced. And so some of the wells in these areas are on decline, yes, sir.

Q. That's what I'm looking for, an individual well to establish, either by P over Z or some production rate, an ultimate recovery as forecast in a conventional engineering way for an individual well.

A. Well, P over Z would not be possible with the oil wells. But we could -- We can forecast ultimate recovery for the wells that are on decline.

But you've got to remember, if they're on decline that means they're below the 700-barrel-a-day allowable. It's too late to worry about it. Once you've gone to that point to establish it, you've already wasted the oil.

Q. On the new wells, have you established the decline so we can estimate their oil recovery?

A. Well, if you refer to Exhibit -- I want to get the right one. Let's see. This would be Exhibit 11. We can't establish a decline for this well. I mean, if you put a decline on that, the well would produce an infinite amount of oil --

Q. When we look at --

A. -- and we know that not to be true.

Q. All right, this is the State K 3?

A. Yes, sir.

Q. All right. When I look at the oil-a-day column, the 700 allowable is -- what? Three lines below the thousand, and this well has never been produced within the allowable range, even for the single well?

A. Yes.

Q. It's always exceeded the allowable?

A. Yes.

Q. Why did you do that?

A. I didn't do that.

Q. Have you taken your wells and conducted what I would characterize to be some kind of step rate production test where you produce it for a sufficient period of time to get a stabilized data point, then restricted it and produced it for long enough to see what consequence you have on the oil volumes recovered?

A. Well, that's -- This particular well, no, that's what I went and talked to Mr. Gum last summer, was running such tests. The conditions that needed to be met to run those were not able to be met.

Q. Why -- I'm sorry, who was setting the conditions for running an actual field test of these wells to see what happened?

A. Mr. Gum was.

Q. And you could not satisfy his conditions?

A. The conditions, we did not feel they could be met at that time, no.

Q. What were the conditions that you felt you could not meet?

A. We had to gain the approval to produce -- to continue to produce at excess rates, even higher than this, from all the operators in the area, and we did not feel at that time -- There were significant disputes and disagreements between the operators, and we did not feel that it would be possible to run such tests, to obtain agreement between everybody.

Q. Well, weren't these wells being produced at capacity anyway?

A. Capacity is not really what -- This well was being produced at pump capacity, not necessarily reservoir capacity.

Q. I'm having trouble understanding what it is that you wanted to do that you could not achieve.

A. We could not get agreement -- We did not feel we could get agreement between the operators.

Q. To produce them any higher than the rates that were being produced then?

A. Yeah, we could go in and physically put in a bigger pump.

Q. Did you ever ask the operators if they wanted to conduct a field test with your cooperation?

A. I did not at that time. I consulted other people within the company. That would not have been my -- my realm of work. I --

Q. All right, it didn't happen.

When we go down and look, could you have taken that current rate and then restricted it below that for a period of time to give us another data point to see the consequence?

A. That could have been done.

Q. And you did not do that?

A. No.

Q. All right.

A. But we did do it in other wells.

Q. All right. Identify for me the wells, so that we have a list of the ones that there was what I would characterize to be a step-rate performance test at different rates.

A. Well, the two best examples would be the two that I've presented, the Diamond AKI Number 1, and the Aparejo Number 5.

There is one other well, and it's very important.

If you go to the exhibit -- okay, here it is, Exhibit Number 5, and you go back five pages within that, and look at the Boyd X Number 5. This is an important one to understand. I probably should have brought it out earlier, but I appreciate -- The Boyd X Number 5, the type test you're talking about was run on this well, because when the well was drilled -- Well, there were two wells on that proration unit.

We did not -- We, Yates Petroleum, did not want to drill another well on that proration unit. That proration unit was above allowable, and we did not want to drill.

We were forced into drilling this well, based upon issues from our partners. They basically required -- They sent an AFE through, and your choices under the JOAs, you either drill it or --

Q. Is this the Boyd 5?

A. The Boyd X Number 5.

Q. Oh, this is the fight with Nearburg?

A. Yes, sir.

Q. All right.

A. They were concerned about this well.

Q. All right. So you've got what I'm asking for in terms of what we've characterized to be a step-rate test on the Boyd X 5.

A. The Boyd X 5 is one of those. These low-rate restrictions are manual restrictions. It's not a bunch of individual ones, but we have -- when the well was brought on, on the right side, for the first -- It had good production for an entire month, and then we have the two rates down here.

This well supports both the type tests you're talking about running, and it shows that the phenomenon exists, plus it furthermore supports my exhibit, the next-to-the-last exhibits, my Exhibit Number 13, because the phenomenon I talked about in Exhibit 13 is exhibited -- is illustrated on this plot.

Q. All right. The Boyd X 5 is on what exhibit you're looking at? What's that exhibit number?

A. Well, the Boyd X 5 data --

Q. Yes, sir.

A. -- is on Exhibit Number 5.

Q. Exhibit 5. What's the time frame Does the time frame show on that display?

A. Well, again, the most recent data is the February data.

Q. All right. I don't have the exhibit, but my question is -- what's the -- is the time frame shown on the display so my engineer can verify what you're showing? Is there --

A. Again, there's not a time frame, this is not necessarily time-frame data, but the most recent data. He's been presented with all the data that I used to construct this plot.

Q. That's my question, all right. So I've got the data?

A. Uh-huh.

Q. The Boyd X 5 is an example of a well we could examine to get a step-rate test on, if you will?

A. Roughly speaking, yes, because the well was produced at very high rates and then manually restricted to produce at very low rates, because we were overproduced -- we were forced into drilling this well --

Q. I understand the argument, Mr. Fant.

A. -- and we did not want to increase the overproduction problem any more.

Q. All right. And you've got some data that you argue would be an example for the Diamond well?

A. Yes --

Q. All right.

A. -- that data is --

Q. You already showed us that.

A. Yeah.

Q. And the raw data is available to my engineer?

A. That is daily production rates, and I don't think that raw data -- The raw data that constructed that plot is not public data, because that is -- that's daily production rates, and there's no forum for presenting daily production rates.

Q. All right. If my engineer needs that, there's no reason he could not have the actual production data?

A. I don't see why not, because the actual production data can be derived from the graph.

Q. All right, other than those two wells, give me another example of a well we can examine that will give us that kind of information. The Boyd X 5, the Diamond? Are there any others?

A. Well, you know, I presented you with the Aparejo 5, and it's the same kind of deal as the Diamond.

Q. All right, I've got the Aparejo 5, I've got three. Are you aware of any others?

A. To my knowledge, there -- I don't know of any others that we've specifically run these type of tests in. And again, the Boyd 5 was not -- we did not go out there with the intentions of running that test. It was simply, that's how -- that was the production life of the well.

Q. I understand. I don't care how it was done; it's there and we could utilize it?

A. Uh-huh.

Q. All right. I'm interested in your argument on cycling production --

A. Yes, sir.

Q. -- where you've taken the wells in the overproduction area, and in order to honor Mr. Gum's requirement, as I understand it, to at least not accrue additional overproduction, you have managed those wells in a spacing unit so that you're not now currently exceeding the 700 barrels a day?

A. Yes, sir.

Q. And the method for managing that is to take a well and cycle its production so that for a certain period of hours it's off production, and then it's back on production?

A. Yes, sir, that's the physical way that it's done.

Q. All right. Within a spacing unit that has a single well -- We don't have any in that area that there's a single well spacing unit?

A. Oh, yes, the State K Number 3.

Q. All right, let's do that one first, the State K Number 3. It's overproduced. In order to get it back to the 700 a day, you have restricted that well?

A. Yes, sir.

Q. And to stay within the 700 a day, the method is to cycle it on what time sequence or interval?

A. I don't have the specific clock numbers that are there, but it's approximately on 70 percent of the time and off 30 percent of the time. That was my recommendation to them, to -- you know, it's a starting point. Then you -- but you have to -- I mean, they have to adjust things to -- You know, they have a target rate, and then they adjust it to fit that.

Q. Here's what I'm trying to understand: Are you working with Mr. Collins, then, for the two of you to determine how that well is produced, or are those his decisions?

A. That decision is strictly Mr. Collins'. I made recommendations on how much they would need to be cut back to get them in, but that is an operational consideration as to physically how it's done.

Q. I'm not -- then I'm understanding what your recommendation is -- What recommendation did you make?

A. Well, the recommendation I made was simply that this well is a 1000-barrel-a-day well. 700 barrels a day is 70 percent of 1000. Consequently, you know, it needs to be cut back 30 percent what it's doing. How they achieve that is -- I mean, there's a lot of operational constraints that have to be taken into account.

Q. Have you tested any of these wells to determine whether or not it could be efficiently done by simply shutting the well in for a period of consecutive days and then producing it on at full capacity to meet the allowable on a monthly basis, if you will?

A. That's a good point, and that was -- that's again what Mr. Gum had proposed to us. There are distinct -- These wells are produced by electrical submersible pumps. That's the only mechanism we have to produce these fluid volumes.

Now, when you shut in an electrical submersible pump for a significant period of time -- now, what I'm talking about there is, say, a week -- You shut a pump in for a week, the probability of it turning back on goes way down.

Q. The pump can malfunction?

A. The pump can malfunction due to gas impregnation of the cable, scaling up of the pump, or paraffin and asphalting, you know, hydrocarbon-type deposits on the pump. It may not come back on.

This is stuff we have discussed with the ESP company that provides these things, this service to us, and it's not feasible to shut it in for extended periods of time.

That's why on these particular examples I looked at 12-hour cycling and one-day cycling. You can take it to two- and three-day cycling, but the effects wear off rapidly. You could go to two- or three-day cycling, but still your effects are going to wear off fairly rapidly.

Q. Do we have a test in the overproduction area to see what the consequences are of taking a well in a multiple-well spacing unit and simply shutting that well in, in order to achieve the allowable limit?

A. We don't have the test, but again, as I testified, anytime you shut in -- When we shut that well in, if we're talking about shutting in, we have to temporarily abandon that well. And anytime you temporarily abandon a well, you run the risk of never getting back into it. In other words, these wells can't simply just be shut in and then turned on a month later.

Q. Your examples of this phenomenon are all on new wells which are the vintage of mid-1994 on?

A. My Exhibit Number 6 is intended to illustrate that this phenomenon exists for 95 percent of the wells that have ever been drilled in Dagger Draw.

Q. All right.

A. So I would say, no, that this phenomenon -- I've studied every well in Dagger Draw.

Q. Okay, let me understand how you prepared Exhibit 6. You've got the wells by name, by operator, and then we have an oil cut and the GOR slope.

A. Uh-huh.

Q. What is the database that allowed you to prepare this summary and the calculation?

A. I have for Dagger Draw a database by well, monthly production, all historically available monthly production for those wells. Yates -- For the wells that are Yates, this database is up to date through February. For other operators, the database is up to date through October. And that -- The other operators, the database I use is *Dwight's*, public data.

Q. All right. So then we're going to have volumes of oil, gas and water from which my engineer can make his own calculation of an oil-cut slope and a GOR slope?

A. Certainly.

Q. All right.

A. It's the same data, and I've provided them with the incremental data for Yates Petroleum.

Q. All right. The time frame in which you selected to calculate the slope, was that for the full performance of the well?

A. For all of the performance for which I have data, which would be -- for Yates Petroleum wells it would be the beginning of the well, up through February. For wells operated by other operators it would have been the beginning of the well, up through October of last year.

And furthermore, I've tried to restrict it to one -- to wells in which I had at least three data points, because I was taught in school that two data points don't define a line.

Q. The Diamond AK 1 on Exhibit 7 is the only example I can find in -- what, South Dagger Draw? Is that your data point in South Dagger Draw, is the Diamond 1?

A. No. Well, if you also look at Exhibit Number 5 and look at the second well, the second page of Exhibit Number 5, which is the collection of -- the big collection of plots, this one here --

Q. All right.

A. -- then turn to the second page, Bone Flats 12 Federal Com Number 2 is a well in South Dagger Draw.

Q. Okay. So when we go through the information, we've got the Bone Flats 12 2 and the Diamond AK 1. These, in today's presentation, are the two examples out of South Dagger Draw?

A. Those are the ones that have been presented again in this table here.

Q. Exhibit 6?

A. Exhibit 6, yes, thank you. Again, wells in South Dagger Draw for which I have data are in this exhibit, and they are included in the 95 percent that have a positive slope.

Q. All right. Let me go to Exhibit 7, then, and see the method here on the Diamond AK 1 and see what's happened.

The data points, the diamonds that are shown on the plot --

A. Yes.

Q. -- those represent data points taken on what time interval?

A. These are daily producing rates. Each one of these represents the production for one day.

Q. This is a daily plot, then. Each diamond is a day?

A. Each diamond is a day.

Q. Okay.

A. They are not absolutely consecutive, I will say that --

Q. All right.

A. -- because there are time periods where we are hooking up the variable-speed drive and the well is not producing.

Q. When we look at the Diamond AK 1, which is down in South Dagger Draw --

A. Uh-huh.

Q. -- is it your position that early-time performance of that well is unstabilized? Do we have that condition occurring down in the Diamond area?

A. Well, I'm not real sure what you're meaning by the term "unstabilized".

Q. Well, let's talk about it so you and I are on the same page. In the first few weeks or months of the well --

A. Uh-huh.

Q. -- there are -- the wellbore is conditioning itself, if you will, and -- I'm a layman, you'll have to help me, but --

A. Yeah.

Q. -- I understand that early-time performance is suspect for you and other engineers because it hasn't stabilized, and you don't have reliable oil, gas and water rates?

A. Well, the problem with using that characterization in Dagger Draw is, Dagger Draw is a highly permeable reservoir, and what people are normally speaking of in that -- they're talking about the transient rate effects that occur.

There's two things you can talk about: transient effects in the reservoir, or you can talk about wellbore storage effects. Wellbore storage effects in Dagger Draw wear off in hours --

Q. Okay.

A. -- because we produce those fluid volumes that that wellbore can contain in minutes at these production rates. Dagger Draw, the wellbore storage is not a significant time component.

But the interesting thing here is, yes, you can change -- you change the rate, but again that same effect of wellbore storage and transient effect is still going on in the reservoir.

So, you know, the important thing is, if you're going to use daily rates, use all daily rates. If you're going to use monthly rates, use all monthly rates. That's the important thing, is to compare apples and apples, daily rates to daily rates, monthly rates to monthly rates. And that's why I presented these as two separate exhibits. Exhibit 5 is monthly data, Exhibit 7 is daily data.

Q. And that's what I'm just trying to clarify for myself, is that Exhibit 7 has got daily rates on it. Your argument for using that is the transient effects that we might see in a reservoir are not an issue of concern for you when you examine the performance of the Diamond well?

A. Well, my basic issue for using these is to show that basically -- using the daily rates, is to show that an instantaneous change in producing rate in daily, day-to-day in the life of these wells, is essentially an instantaneous change.

And instantaneously changing the producing rates, this phenomenon exists. It exists on an instantaneous change, and then Exhibit 5 shows -- 5 and 6 show that those changes occur over time also.

So that -- It's just showing that if this -- Every time we look for this phenomenon, it shows up. You know, that's the reason for presenting those two sets of data.

Q. When I look at Exhibit Number 13, we're looking at the 24 cycle?

A. Yes.

Q. And then the second page is a 12-hour cycle?

A. Yes, sir.

Q. Is there anything I see on this exhibit that supports your theory that producing the wells in a restricted fashion is going to reduce ultimate recovery? That's not apparent in this exhibit, is it?

A. Which type of restricted production are you talking about in that particular statement?

Q. I'm talking about taking all the wells back to 700 barrels a day and keeping them there and denying your request.

A. How are we going to take them back?

Q. How are you going to take what back?

A. How are we going to restrict the wells?

Q. That's up to you, managing your production, to abide by the 700 barrels a day.

A. Okay.

Q. And my question for you, if you do that, what is your argument that you're not -- that you're reducing ultimate oil recovery in the pool?

A. Again, this exhibit, just to tie it --

Q. Yeah.

A. -- just to answer your question, this exhibit is not -- is intended to show that the cyclic production method is essentially, over time, going to be equivalent to slowing the well down. Just, you know, putting a continuous restriction -- In other words, if we had a variable-speed drive, just slowing the well down. Just like we did on the Diamond AKI Number 1, slowed it down, the oil cut went down.

Therefore, if the oil cut goes down and also the GOR goes up, which the data suggests it will, those two things, producing any reservoir in a state where you are increasing your water cut and increasing your GOR is a wasteful process in a depletion system, because it will lower your ultimate recovery.

We're only going to get a certain amount of fluid out of this reservoir. If we're taking out excess gas and excess water now, then at the end of the life of the well, that's oil, gas and water that we will not recover. I don't care about not recovering the water at the end of the life of the well, but it's oil that we will not recover at the end of the life of the well.

Q. All right. And you make that argument based upon -- Your contention is, by looking at that oil cut and finding that at higher rates you get a higher oil cut --

A. Yes, sir.

Q. -- you contend that that is going to increase ultimate oil recovery from the pool?

A. Yes, sir.

Q. All right. If the Commission accepts that contention and provides for an increased oil allowable in North Dagger Draw, your recommendation is 4000 barrels a day?

A. That is my recommendation, based upon the data.

Q. And based upon -- What data demonstrates the need of the 4000 barrels a day in a 160-acre spacing unit?

A. First of all, the data suggests that 40 acres is the proper spacing.

Q. All right.

A. Secondly -- Well, I've got to find the right --

Q. Let me see if I can summarize it for you, and you tell me if I've done it right.

If we're assuming that the newer wells with this capacity is on average about 1000 barrels a day --

A. Uh-huh.

Q. -- is that what you're saying?

And then in 160 acres we might have four of these wells that would do that, you simply multiplied it and got the 4000; that's what's --

A. That's where the number came from, yes, sir.

Q. If they accept that and then everybody in the pool has an equal opportunity to test your theory and see if they can in fact enjoy that privilege, what is your argument as to why the Division should cancel all the overproduction for you and whatever other operators that have exceeded that limit? Why should we cancel the overproduction?

A. Basically, first of all, 40-acre drainage is what these wells are affecting, 40 acres is what --

Q. All right, let me interrupt --

A. This my argument.

Q. All right.

A. 40-acre drainage, that's what the wells are draining. If they're only draining 40 acres --

Q. -- you ain't hurting anybody?

A. -- you ain't hurting anybody.

Q. All right.

A. Furthermore, the wells have been produced thus far at the efficient method, thus far they have been produced at the efficient method.

Furthermore, restricting them to get -- to do that, would cause waste. So correlative rights are not an issue, and waste is at issue. That's why we believe that the overproduction should be canceled.

Q. All right. If your theory is that you're only affecting 40 acres and therefore the overproduction is going to be production you would have already gotten over time, and you're not draining it from anybody else -- right?

A. The production -- The overproduction is simply oil that's from the 40 acres for that well.

Q. Okay. In order to balance with the pool, though, what's wrong with simply shutting that well in, making up the overproduction, and restoring the well back to production later, at whatever you want to take it to, to stay within the new limit of 4000 a day? Why can't you postpone the time in which you commence producing this well at the higher rate, sir?

A. Because you can't -- It's not a good practice to just shut in oil wells for extended periods of time.

Q. Would it have anything to do with the fact that if that well is shut in because of pressure depletion in the reservoir, that oil production which you might otherwise get would have gone to another offsetting well?

A. I do not believe so.

Q. Okay. So the only reason not to shut it in is that you think there may be some operational problems in restoring it to production, and because you conclude that that production has been drained from only a 40-acre tract?

A. I want to make sure I heard that correctly.

That -- well, I mean, forgive me --

Q. I'll do it again. The reason for not shutting the well in is that there's an operational concern about what may happen in the field with the ability to restore that well to production, because you said there was operational problems, if you will --

A. Uh-huh.

Q. -- as opposed to reservoir conditions that might preclude that well from returning to its level of capacity prior to shut-in. Is that a correct statement?

A. I don't believe that's the only thing. There are historical precedences that shutting in oil wells, regardless of what's going on from the offset wells, but shutting in oil wells is not a good idea to do it for an extended period of time.

Q. Define "extended" for me, sir.

A. A month or more.

Q. All right.

A. You know, in this particular reservoir you're looking at "extended" being -- from an operational standpoint, you're looking at "extended" being like over a week, because if we're talking about over a week, it would require going in, pulling the sub pump, and temporarily abandoning the well.

Q. Yes, sir.

A. And then you might -- you might get back into that well, you might not. There would be tremendous expenses associated with it, for no benefit.

Now, from the reservoir standpoint, I consider extended shut-ins to be on the -- in general, on the one-month basis, that's just -- you know, that' something that the OCD and people -- you know, a month is a magic time frame in the oil and gas industry, because that's the period over which we report production.

But shutting them in -- I mean, there's leasehold problems, you've got to make sure that you don't lose these leases for some -- for that reason. There is the operational problems of, we cannot just shut these wells in and come back a month later and turn them on. The odds are, they will not turn on. And then, you know, require the abandonment.

And so yes, there are reservoir conditions, there are land conditions, and the basic premise of it is, it doesn't affect anything. We're talking 40-acre drainage in this area.

Q. All right. When you look at 40-acre drainage, have you and Mr. May attempted to calculate drainage areas in a conventional way, using a ϕh map or a net pay isopach and trying to take an estimated ultimate recovery and backing it into a drainage calculation?

A. That's an interesting point. One of the first things I was concerned about when I started working Dagger Draw was, how did we get this much fluid out of this rock? And so I began a study with Schlumberger. Some points were actually pointed out to me by Nearburg.

But basically what we're finding is, we can't characterize at this point the ϕh of reservoir, because we can't characterize the porosity, probably. And if you can't do that, then you can't do the other.

So trying to do that right now with the tools that are available would be grossly in error, I believe, and that's why I have not done it.

Q. All right. When you look at trying to estimate drainage, then, you have examined some interference data that's on one of these exhibits, and you have some examples where you contend that there are relatively few, in which we had the Thomas and the Warren as an example?

A. Yes, that was presented to show methodology.

Q. Yeah, and the methodology was, one, to show an effect of rate so that -- The older well, I think, was the Warren well?

A. Yes, sir.

Q. You bring the Thomas well on later, and we see the Warren well's rate of oil production decline at a steeper angle?

A. Change, definitely.

Q. Its changed to a steeper -- All right.

Did you also examine the issue of interference from a pressure standpoint?

A. The data is not there to -- you know, as I presented in my direct, no, that's not there.

Q. Okay. So your argument on drainage is that the only useful way to get to the drainage conclusion is to look at the offsets and see if the performance of the newer well has changed the slope of the oil production rate on the offsetting wells?

A. Yeah, absolutely. If it doesn't change them, then there's no interference.

Q. So -- And that would be the basis, then, for your conclusion that you have only 40-acre drainage areas in the North Dagger Draw?

A. That's my conclusion, yes, that 40 acres is the proper drainage, the proper spacing for this area of North Dagger Draw, yes, sir.

Q. That's how you went about it?

A. Uh-huh.

Q. When we get to South Dagger Draw, did you apply that same method?

A. Yes, the wells are not spaced out quite as closely, but where I was able to, yes, I applied that method.

Q. And do we have an exhibit somewhere here this morning that gives us examples of areas where you've examined to look for the interference of rate of one well against another?

A. Honestly no, because -- You know, obviously no, I do not have that example presented here today; I've not presented it.

But again, you've got to go back to -- The primary reason for that drainage-area study was our development in North Dagger Draw.

Q. All right.

A. I mean, that was the primary reason for it, and that was -- Although we were looking through the whole thing, you know, this data as presented here had only been prepared for the areas of new development in North Dagger Draw. That's where most of our development is.

MR. KELLAHIN: That's all the questions, I have, Mr. Examiner.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Padilla?

MR. PADILLA: I have a few questions, Mr. Examiner.

EXAMINATION

BY MR. PADILLA:

Q. Mr. Fant, when you talk about 40-acre spacing or 40-acre drainage, you also go back to development on a 40-acre basis. How far back?

A. Forgive me, I'm not really understanding what you --

Q. In other words, you're talking about 40-acre drainage today.

A. Uh-huh.

Q. In fact, 40-acre drainage has been the case in the North Dagger Draw for a number of years?

A. Yes, sir. Yes, sir.

Q. And when you look at your Exhibit Number 5, all of those wells are on 40-acre drainage; is that right?

A. Well, not all of these have been -- They're on 40-acre locations, but not all of these are fully developed on 40 acres all around them, just as Mr. Kellahin pointed out. The State K 3 is developed on 40 acres on half of its offsets and not on another half.

Q. But where you do have even that situation, your testimony is that you're not draining more than 40 acres?

A. Yeah, I'm seeing no interference between the

State K 3, even in that instance, between the State K 3 and its adjacent 40-acre offsets or its 80-acre offsets surrounding it, and --

Q. So in fact, there's no effect on the correlative rights of the owners of the undeveloped acreage in those situations?

A. Yes, that is my basic point here, yes.

Q. And you can take any situation for any of these drainage areas, you can go back to the mid-1980s and essentially reach the same conclusion?

A. There are areas in this field where there is more interference between the wells.

Basically, the rules that will be changed here will affect the areas of new development, and so that's why my focus was on these areas of new development.

A place that's already developed on 40-acre -- you know, has all the 40 acres and all the wells have declined down to 50 barrels a day, the rule changes are basically moot.

The difference is that in this area, we're seeing 40-acre drainage, and it's important to be able to optimally develop the field, not only develop it, but produce it optimally.

Q. In terms of drainage, your testimony isn't any different than Mr. Boneau's testimony has been in earlier hearings involving the North Dagger Draw Pool?

A. Dave? I'm not sure -- You know, in all honestly, I'm not sure what Dave exactly presented, and I'm -- I -- you know -- I was not involved in --

MR. KELLAHIN: We have that problem too, Mr. Fant, on occasion.

THE WITNESS: What?

MR. KELLAHIN: I shouldn't have said that.

THE WITNESS: I talked to him, yeah, but what he said I'm not always sure. He can talk over my head.

MR. CARR: I'm going to object to Mr. Kellahin's editorial comments.

EXAMINER STOGNER: So noted.

THE WITNESS: But Dr. Boneau -- You know, I'm really hesitant, without knowing what he said, to answer that in either way. I don't mean to be evasive, but --

Q. (By Mr. Padilla) But really, generally, in terms of 40-acre development on a 40-acre basis is something that I think Mr. Boneau advocated at some point.

A. Yes, obviously we've developed a few wells on 40 acres.

Q. And Conoco has advocated 40-acre drilling, essentially, except that the bits of land may be -- as I understand it, the area was not downspaced?

A. No, we're -- You know, we're not touching or intending to touch the 160-acre-proration-unit issue or the 320-proration-unit. The land issues involved with that would be phenomenal, to go back and actually break those proration units up. That would be -- But we do believe that 40-acre development is proper for the reservoir.

Q. Mr. Fant, what was the fight with Nearburg on the Box X Number 5?

A. The Boyd X?

Q. Boyd, I'm sorry.

A. That related back to an issue, as I remember, and forgive me, I'm an engineer, and it was a land issue as to whether or not we had given them notice on that well, whether or not we would participate in that well.

They had sent a proposal to us, we responded, there was some mix-up as to the date as to which the response was made, and there's only 30 days allowed for that response. And so they had a position that we were nonconsent in the well, which in Dagger Draw, you know, is a 200 percent -- you know, cost plus 200 percent. So you're talking about a lot of money.

MR. CARR: Wasn't that a dispute over whether you had paid your share under a pooling order?

THE WITNESS: Well, yeah, and whether or not we actually notified them as to whether or not we were going to participate.

Again, it was a land-legal issue that was eventually settled. They were concerned about -- They wanted that well drilled at that time, because it was still -- there was still a dispute as to who would own it, and they wanted it drilled.

And so we drilled it, we won -- The case was settled in our favor, there was no nonconsent and we -- and -- you know, but the well had been drilled, and basically Nearburg had requested that that well be drilled.

Q. (By Mr. Padilla) But that was the subject of the compulsory pooling hearing before --

MR. CARR: I was wrong on that.

THE WITNESS: No, I don't believe that one was the subject of a compulsory pooling, because the Boyd X Number 3 had been drilled several years before -- or not several years but a year or so, two, before, and the Boyd X 3 established Yates Petroleum as the operator of that proration unit.

MR. CARR: Mr. Stogner, Mr. Kellahin advised me that I misspoke.

It involved proposing a well under a joint operating agreement and whether or not, after it was proposed by Nearburg, Yates had responded within the time frame set in that agreement, so it was a question surrounding that kind of --

MR. KELLAHIN: If it will aid you, Ernie, we can give you that kind of information. It was a contractual dispute.

MR. PADILLA: I don't think I have any other questions.

EXAMINER STOGNER: Thank you.

Mr. Kendrick?

MR. KENDRICK: I have no questions.

EXAMINER STOGNER: Mr. Bruce?

MR. BRUCE: Just one.

EXAMINATION

BY MR. BRUCE:

Q. Mr. Fant, would these principles you've enunciated today about increasing oil rate and decreasing GOR apply generally to oil wells throughout the Dagger Draw and Indian Basin areas?

A. I'm -- I have not studied in the Indian Basin, so I'm not comfortable making that assessment, to make any direct statement.

But yes, they are. I would think that on an intuitive basis, it should be maybe inspected. I do not deal with Indian Basin or the Indian Basin Associated Pool. I'm not responsible for those.

MR. BRUCE: Thank you.

EXAMINER STOGNER: Mr. Carroll?

EXAMINATION

BY MR. CARROLL:

Q. Mr. Fant, do you know the amount of the approximate overproduction, according to Yates' records?

A. The approximate overproduction for the ten proration units would be approximately 1 million barrels, slightly over, maybe 1 to 1.1. But since we've restricted the wells, it's probably closer to a million barrels.

Q. That's for North Dagger Draw?

A. That's for proration units in 21, 28 and 29. Not all of them, but some of the proration units in 21, 28 and 29.

Q. You mentioned Section 27 earlier, that there was overproduction there?

A. Yes, that is operated by Nearburg --

Q. Oh, okay.

A. -- Production Company. And there, I believe, is one proration unit in South Dagger Draw that I know of that's overproduced.

Q. And what's the amount of that overproduction?

A. I do not know the amount, but it's operated by Marathon. You know, that's just the facts.

Q. Okay, Mr. Fant, you testified that Yates is aware of the pool rules for the North Dagger Draw and was aware that the wells it operated were capable of producing in excess of the allowable.

When you became aware of that, why did you not seek relief from the Division to allow that overproduction?

A. That question has been posed to me before, and basically if I had come in here 18 months ago, when we initially had wells of this capability, I don't believe anyone would have believed me that this was a long-term effect. That's part of it.

Everybody in our company and everywhere else has been -- We've been amazed by the productivity of these wells. And, you know, I'm not trying to say, you know, everything's, you know, perfect about the way we did everything. But if I had come in here even a year ago, nobody would have believed me. I don't believe I would have believed me, in terms of long-term productive capabilities and the needs for higher rates, because these wells maintain these productive rates for these extended periods of time.

Q. Well, I guess nevertheless, the rules were still in effect, and Yates disregarded the rules and produced these wells in excess of the allowable.

A. I'm not going to deny that.

Q. And what happened last summer when you met with Mr. Gum regarding the test? You said that Mr. Gum wanted you to get the other operators' approval to --

A. To run the test.

Q. -- to produce these wells in excess of the allowable? Did you contact the other operators?

A. I did not. I don't think anybody else did. It was discussed internally. This was in the midst of the Boyd X 5, and I'm sure you remember a few force-pooling hearings that we had between ourselves and Nearburg, and Nearburg was the major offset operator that we would have been dealing with, and we were not even on talking terms. It was a bad situation. I'm not saying that everything was done right; I'm just saying that it was not pursued for that reason.

Q. Mr. Fant, what would be your recommendation if the Division required that Yates make up this overproduction? How would it be made up and over what period of time that the make-up be allowed to -- be made up?

A. My problem there is that that's a recommendation that I can't make, as far as how, exactly, we would do that within Yates Petroleum. That's something that would be controlled on a level above mine, as to what would actually be proposed.

I would be willing to say it would take probably on the order of years.

Q. Years?

A. I'm just being honest with you.

Q. And it was your testimony that restricting production on these wells would result in waste?

A. Yes.

Q. And that there is no impairment of correlative rights due to overproduction in these wells?

A. That's correct.

Q. So if the Division didn't require the makeup of the overproduction but still wanted to somehow penalize Yates for disregarding its rules, do you have any recommendation as to what alternative method of penalty there would be that we could impose?

A. Again, you know, I don't feel comfortable -- I don't feel I'm in a position to make those recommendations. That would be -- I've not discussed -- You know, these other things I've discussed with management of what we're talking about, and I would not feel comfortable making any recommendations and speaking for the family on that account. I just don't feel -- You know, I'm sorry, I just don't feel comfortable making any recommendations of that nature, on the record.

Q. I don't know if you know the answer to this question. Is it the same working interest percentages in Section 21 and 28?

A. Oh, well, we could refer back to this exhibit, I believe Number 1, and we can see that, no, they're -- the percentages are dramatically different.

You can look in the upper right-hand corner and that will show you what Yates Petroleum's interest is. In the upper left that will tell you what Conoco's is. The lower left, that will tell you what -- approximately what Nearburg's is.

And those are the three main operators in the North Pool, and that's what drove the -- making this map and presenting them, is those particular situations.

Q. Now, Mr. Fant, when a well is shut in for repairs for, let's say, 24 to 36 hours, what is the well performance after that, after that shutdown?

A. Well, it's generally basically -- You know, that's a very short period of time. We generally have one day of high water production, and then it's back on, you know.

You know, for the most part, our wells are down for less than 24 hours. We -- you know, these are so -- These wells are so productive that you don't want to leave them down for any significant period of time.

MR. CARROLL: That's all I have, Mr. Examiner.

EXAMINATION

BY EXAMINER STOGNER:

Q. Should it be necessary to shut these wells in

for, as you quoted, years --
A. Well, shutting -- if we shut them --
Q. Well, I haven't finished my question.
A. -- in, it would not take years --
Q. Let me finish it first. If you shut these wells down for, as you said, years, would they suffer or would that property suffer from any drainage from offset wells that have met the allowable and are continued to produce at a 700 -- or, for that matter, 4000-barrel rate?
A. Forgive me. I may have misled earlier. If the wells were completely -- If everything was completely shut in, it would be under a year for things to get back in line. That was maybe a misconstrued -- something I did not state properly.
My contention is, I don't believe -- I really don't believe -- I believe that 40 acres is what these wells are draining, and I think that they would -- that -- from a drainage standpoint, I don't believe that would occur.
Q. How about pressure decrease?
A. Well, I have one well -- I mentioned the Ross Number 7 -- I've been monitoring for over a year, and it has essentially not dropped.
Q. So you're not concerned about pressure, depletion?

A. Yeah, that's what -- You know, pressure and depletion are much the same, and, you know, I don't -- I don't believe -- You know, it's my position that these wells are basically affecting, generally -- I mean, there's going to be instances, just as we found five percent that did have some interference across that distance. But for the most part, no.

Q. Okay. If a well was shut in for a year, are you saying that it would have the inability to come back on, given the proper recompletion?

A. There is always the danger that you're going to have deposition of scales and stuff in places that it can damage that. It may -- you might be able to -- You should be able to recover it, the wells, but that's not -- there is no guarantee on being able to get back into a well, both from a reservoir standpoint and just a mechanical standpoint.

Q. Are there ways to, say, quote, mothball, like antiscalers or scale prevention --

A. Well, certainly --

Q. -- if you shut a well in for a year?

A. Well, certainly if we were required to shut these wells in, which we would certainly hope that we would not, the first thing we would do is, we would temporarily abandon the wells, under OCD rules, which would require the

-- you know, and for ourselves we would put scale prevention and things of that nature down in the wellbore and beneath the wellbore.

But it still would not -- We cannot control what goes on beneath the packer -- well, beneath the bridge plug in a temporarily abandoned well. Mother Nature takes over down there. We can control what happens above it, but we can't control what happens below.

Q. Was it your testimony about -- I'm a little confused on the relationship on the increased oil versus the GOR. Does that -- Do we see that the more oil that's produced, the GOR goes down? Is that your contention?

A. Yes, sir, that's what the data shows.

Q. What happens to the gas that's left in -- left in the reservoir? Does it form a cap, or does it go into solution?

A. Well, I do not believe that we have enough vertical migration of fluids in this reservoir to actually form a secondary gas cap, within the production time frames.

It becomes free gas within the reservoir, in that you're leaving more gas behind. For every barrel of oil that you take out, the gas that remains in the reservoir aids in the gas expansion, the solution gas drive production mechanism. And keeping that gas in the reservoir maintains that production mechanism over a longer period of time.

Q. Are you familiar with the term "illegal oil"?

A. No, sir, I'm not.

Q. "Illegal oil shall mean crude oil production in excess of the allowable as fixed by the Division."

Now that you are, any oil that's overproduced, you said up to 1, 1.1 million, would you consider that illegal oil, under our terms?

A. By that definition, I would say that that is true.

Q. You had mentioned that perhaps if the wells were shut in, there could be a chance of lease expiration, or the lease running out or something to that matter?

A. I can't -- I'm not -- I can't speak for any specific lease, sir.

What I do know is that most leases that I have dealt with historically contain evergreen clauses that speak of the lease remaining in effect so long as hydrocarbons are produced.

And so total -- You know, total shut-in could mean no hydrocarbons produced. And, you know, I don't know the actual ramifications, but it is a concern that I needed to consider.

Q. When is your -- How far back do you know of any well -- or proration unit, rather -- being overproduced, in an overproduced status?

A. Are you -- Specifically in relation to the ones that are overproduced right now?

Q. At any time.

A. At any time? One proration unit was overproduced, I want to say, in 1992, and that proration unit was in Section 1 of -- What is this? 20 South, 24 East.

And it was the northeast quarter section of that one, and when brought to -- when the issue came up, the well was -- the proration unit was restricted and brought back into line. That's the earliest that I have actual data.

Many of these have been overproduced at a time, and then simply through natural decline, you know, a month later, they're not, which is what has been typically used to keep wells -- for wells -- for proration units to get back into their status.

Q. Going back up to Sections 21, 28 and 29 --

A. Yes, sir.

Q. -- do you know when any or all of these proration units, when they became overproduced?

A. The earliest one I would believe to be overproduced would have been the southwest quarter of

Section 28, the State K 3, basically last October -- October a year ago, forgive me, 18 months ago.

Q. October of 1993?

A. 1994, excuse me, sir.

Q. I'm sorry, 1994. Do you know if any of the others were overproduced prior to that?

A. The -- I know that -- Yeah, forgive me, the northeast quarter section of 29 had been overproduced for a while, but had been -- had gotten back to a nonoverproduced status.

And then a few months ago, the Binger Number 2 was drilled, and it went back up again.

EXAMINER STOGNER: Are there any other questions of this witness?

MR. CARR: No further questions.

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Let's take a 15-minute recess at this time.

(Thereupon, a recess was taken at 10:48 a.m.)

(The following proceedings had at 11:10 a.m.)

EXAMINER STOGNER: This hearing will come to order.

Mr. Carr, do you have anything further to present?

MR. CARR: No, sir, I do not. That concludes our presentation, Mr. Stogner.

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: Mr. Examiner, we have a presentation to make. I'd like to recommend a procedure and see if it's acceptable to the parties.

I would like to present Mr. Hardie this morning to focus on North Dagger Draw. He has done some work in South Dagger Draw, but that's not yet completed. I would like to focus on North Dagger Draw.

I'm going to present Mr. Beamer, who is our petroleum engineer. You need to recognize that he has not had time to complete his reservoir study. He's going to describe for you his concerns so that at least we'd have those out in front of the participants, so they can see our point of view.

I anticipate that we can make this presentation within the next hour. At that point, I would seek your approval and the concurrence of counsel to ask that this matter be continued but put to an expedited schedule so that we can come to some sort of conclusion, but I feel compelled to ask for a continuance in order to give my reservoir engineer some time to study his properties and his concern. So that's my agenda and that's what I'm proposing to you, sir, for approval?

EXAMINER STOGNER: Mr. Carr?

MR. CARR: As you're aware, Mr. Stogner, early this week, perhaps late last week, Mr. Kellahin contacted me on behalf of Conoco and expressed concern about their ability to be ready, and he filed, in fact, a motion with the Division requesting a continuance of the case.

At that time I advised the Division that Yates was prepared to present its case whenever the Division desired, that the problem was a serious problem for us, we had met with Mr. Gum, we had committed to him to pursue it on an expedited basis, that we were prepared to present our side of the case anytime and any place the Division desired that we show up and put our case on, and that we were not trying to take advantage of any other operator in the pool in terms of pushing things forward on any kind of a time frame, and that we recommended that the Division review requests of other operators for extension of time based on their expressed need for the continuance, and that we would not take a position on that but ask you to look at what they were asking for and, if it was reasonable, whatever you desire is fine with us.

EXAMINER STOGNER: Mr. Carr, should it be necessary to continue this --

MR. CARR: Yes, sir.

EXAMINER STOGNER: -- because I think it was necessary pursuant to your arguments in answer to Mr.

Kellahin's request for Conoco, to get this matter set today and start hearing it today --

MR. CARR: Absolutely, we were happy when you did.

EXAMINER STOGNER: -- should, subsequent to this, it be necessary to continue it to a later date, May 30th or another date past that, is it your contention -- and I understand that Yates has voluntarily -- or has seen to it that the proration units are now meeting their allowable, will continue to do so until such time as we issue an order --

MR. CARR: Yes, sir, they would do that.

EXAMINER STOGNER: Okay.

MR. CARR: They would stay at the 700-a-day or below.

EXAMINER STOGNER: Mr. Kellahin, why don't you go ahead and proceed?

MR. KELLAHIN: All right, sir.

EXAMINER STOGNER: And we'll take your motion under consideration subsequent to your presentation.

MR. KELLAHIN: Mr. Examiner, I have passed out to the Division and to opposing counsel a copy of Mr. Hardie's geologic presentation, and I've also included Mr. Beamer's tabulation of data that he's got, and so you should have a full set of our documents for today's exhibits.

BILL HARDIE,

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. Hardie, for the record, sir, would you please state your name and occupation?

A. My name is Bill Hardie. I'm a senior geologist with Conoco, Inc., in Midland, Texas.

Q. You have to speak up in here, Mr. Hardie. That microphone is not going to help you; it's for the court reporter and does not amplify your voice.

A. Okay.

Q. On prior occasions, sir, have you testified as a petroleum geologist, in particular with regards to geologic issues in North Dagger Draw and South Dagger Draw?

A. Yes, I have.

Q. And in fact, you've done so on a number of occasions?

A. Yes.

Q. Have you prepared for consideration by the Division Examiner a geologic presentation of your opinions and conclusions concerning North Dagger Draw?

A. Yes, I have.

Q. And you have those here today?

A. Yes.

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

EXAMINER STOGNER: Are there any objections?

MR. CARR: No objection.

EXAMINER STOGNER: Mr. Hardie is so qualified.

Q. (By Mr. Kellahin) Mr. Hardie, let me have you turn, sir, to what is marked as Conoco Exhibit Number 1. Help us get oriented as to the identity of the exhibit, how the information is displayed, and then we'll talk about what it in fact shows.

A. This is an isopach map, a thickness map, of the Cisco/Canyon dolomite reservoir across the North Dagger Draw-Upper Penn Pool. Now, the contours are such that -- they're color-coded such that the thinner intervals are dark blue, and then it grades up through greens and finally into yellow as it gets thicker and thicker.

Shown in the heavy red line is the outline of the North Dagger Draw-Upper Penn Pool. Also shown are -- is a lighter pink line within the North Dagger Draw Pool that shows the area of proration units that are in violation of the allowable, and those consist of all or parts of Sections 21, 27, 28 and 29, in Township 19 South, Range 25 East. Those are, again, shown with the lighter pink outline. They form a contiguous block in the middle of the pool.

The well --

Q. We're looking, then, at -- There may have been some nomenclature changes, perhaps, in the pool boundary, but to the best of your knowledge this represents the pool boundary for North Dagger Draw as to what point in time?

A. As to the latest records that we had available in our office.

Q. Approximately, what's --

A. Yeah, the pool is constantly growing because of all the development, so this may not accurately reflect the pool conditions today. It may in fact be bigger.

Q. Well, but within the last month, is this accurate to that extent, or is this vintage earlier than that?

A. I'd say within a couple of months.

Q. All right. When we look at the North Dagger Draw reservoir, you have mapped what you call the Cisco dolomite isopach?

A. That's correct.

Q. And what does that mean?

A. That is the reservoir itself. We're fortunate in this -- in the Upper Penn Pool, that the producing facies is dolomite -- dolomitized, and you can essentially isopach or map the dolomite and determine how much reservoir you have available.

Q. When we look in the area of the overproduction that you've described in the pink area, what is the reservoir quality when you examine the dolomite thickness in that area, as compared to the rest of the reservoir?
A. In terms of thickness, the violation area that I'll call that, is centered in the -- along the axis of the fairway.
I would point out, however, and this will come up in later testimony, that the worst violations within that violation area occur in the south half of Section 29 and the south half of Section 28, which --
Q. We are moving into an area which is thinner, then?
A. That is correct.
Q. And it goes to a blue area in the south half of that violation area, where you have less reservoir thickness?
A. That is correct.
Q. All right. Is there a structural component of the reservoir in the violation area?
A. Yes, there is.
Q. All right.
A. It's on the next exhibit.
Q. When you isopach the dolomite here, from a geologic perspective is there geologic support for any

engineering conclusion or opinion that you have pressure communication across the pool?

A. There's a strong indication that wells that are violating the allowable are producing out of the exact same reservoir zones as wells that are not in adjacent areas. So they are in -- They're in the same reservoir zones, they're competing for.

Q. Let's look at Exhibit Number 2, then. Would you identify and describe that exhibit?

A. Exhibit Number 2 is a structure map on the top of the Cisco dolomite reservoir, so we're looking at an elevation on the top of the field itself. A lot of the same components are on this map as well.

Q. All right, let me make sure I understand what you've done. You have an approximation of a contour line in red that is similar to the isopach line of the dimensions of the reservoirs currently known?

A. The heavy red line along the boundaries of the reservoir on this map represents the zero dolomite line.

Q. Okay. Within that, then, you have displayed the structural components of the reservoir?

A. That is correct.

Q. Apart from that, explain to us the other color codes. The pool boundary now is blue on this display?

A. That's correct.

Q. What are the other color codes?

A. On this one, the thin green line represents the area of allowable violations.

Also, I'm showing Conoco's acreage position to some degree with colors. The solid yellow color indicates that Conoco operates the acreage. The crosshatched yellow indicates that we have a working interest in that acreage but do not operate it.

Q. Within the violation area, then, Conoco would have a working interest, but they're not the operator of any spacing unit or any well?

A. That is correct.

I'm also showing by the color of the well symbols some of the newer drilled locations, so it can give you at least a sense of how the field is developing. The black well symbols, the black oil well symbols, are wells that were drilled early in the history of the field. The red or pink well symbols are those that have been drilled in the last year and a half or so.

So that gives you a feel for where the development, the recent development, is occurring. And as you can see, most of it is occurring in the violation area.

Q. The open pink circles are locations and not actual wells at this point?

A. That is correct, those are staked and permitted locations.

Q. Okay.

A. Not drilled.

Q. What's your knowledge of the chronology and history with regards to the sequence in which these wells were drilled, particularly as development occurred in the violation area?

A. In the violation area, I think -- my knowledge isn't perfect, but there was a significant stepout drilled by Nearburg in the -- I believe it was in the south half of Section 28. If I'm not mistaken, it's what I have labeled as the Nearburg K 1. And that was, at that time, one of the farthest eastern stepouts drilled in this reservoir, and it was a very successful well.

Q. What's the approximate vintage, then, we're talking about?

A. I'm guessing that was two years ago.

Q. All right. Prior to that time it was generally assumed among the geologists that as you moved east, then, you were going to move out of this dolomite reservoir?

A. Not necessarily move out of the dolomite, as you are going to go dip down structurally and go into the water leg, so that -- You would find reservoir, but it would be water wet.

Q. As a point -- As a result of that new information from the Nearburg well in 28, then, what happened?

A. That well was a significant stepout. It proved that in fact the reservoir did not dip down as much as operators had previously thought, and it basically set off a lot of drilling activity in what has now become the violation area.

Q. Okay, anything else about Exhibit Number 2, before we go to the next display?

A. Just, if I would point out the relationship between the area that's in allowable violation is slightly lower than the older portion of the field, but otherwise fairly similar in structural elevation from the older part of North Dagger Draw.

Q. Is there any structural component to the reservoir that would geologically limit the pressure communication in the reservoir?

A. As -- This will become a little more apparent when we look at some of the cross-sections I have developed. But as you move to the flanks of the field, reservoir barriers, which we look for, typically being a thick shale, those begin to appear.

Toward the heart of the field, the axis of the dolomite fairway, there's pretty strong indication that there's good vertical communication, because these reservoir barriers, the little shales that we look for, become very thin and have in many cases been compromised by vuggy porosity or fractures or whatever.

Q. Within the violation areas and those spacing units adjacent to that area, do we have any geologic feature that would limit or restrict fluid movement?

A. There are some, and I think we can discuss those at length when we get to the cross-sections.

Q. All right, let's do that. Let's look at Exhibit Number 3.

A. You may want to refer to one of the maps when you're looking at the cross-section, so you can see where they -- the wells that they pass through.

Q. Let's leave Exhibit 2, then, as our locator map, and we're going to look at Exhibit 3, which is your first cross-section, it's the A-A' cross-section. You're running northwest, then, towards southeast and then finally south.

What's the purpose of constructing the cross-section in this manner, Mr. Hardie?

A. I prepared these two cross-sections, this one and the one we'll look at next, to show the stratigraphic relationships between the areas of the reservoir that are obeying the pool regulations and those areas which are violating the pool regulations, to see if there's any stratigraphic component or any major stratigraphic differences across those areas.

Q. And what did you conclude?

A. That there are lots of stratigraphic changes in the field, and there are some that occur across the violation area.

Q. Are there any stratigraphic changes of significance, such that the wells in the violation area would not affect those wells that are not in that violation area?

A. No, in fact, it's quite the contrary. The stratigraphic relationships that we see indicate that the violation wells would drastically affect offsetting production.

Q. Give us an example of how you reach that conclusion.

A. Okay, let me first of all describe what the cross-section is showing.

The color codes that I have used, purple indicates the dolomite; this is the reservoir at Dagger Draw. Blue indicates limestone; that's a nonreservoir lithology. And of course the shale is shown in brown, again a nonreservoir lithology.

Also shown on this cross-section is a dashed red line that runs across at an elevation of minus 4300 feet subsea. This is a significant elevation in that it's highly unlikely that you would be able to complete an economic oil producer below that point.

So when you're looking at what's available in terms of reservoir, to complete, you need to be looking above that dashed red line, and you need to be looking for the purple dolomite.

As you look at this cross-section, it's drawn from the Yates Patriots 2 and 3 on the left or the northwest side, then it passes through the allowable-violation area, beginning first of all with the Lorene Number 1, and then the violation area continues through the Ross Number 1 "IZ", the State "K" Number 3, and the Tackitt Number 3. And then as we're moving to the right, we encounter Mewbourne's Number 1 "B" State, which is a well that is in compliance.

As you move from northwest to southeast in this cross-section, you're moving from the thickest part of the reservoir to its feather edge. And as you can see, the dolomite gets thinner as you move to the southeast, mainly because of the development of these limestone stringers that occur, and those are nonproductive rock.

So as you look at what's available to complete above that datum of minus 4300 feet, you can see that it gets significantly thinner in the area of violation. And our contention is that there's not nearly as much reservoir there to drain as you have in other parts of the field, so that a violation in that area has dramatic effects on correlative rights, in that it can drain offsetting acreage.

Q. For the wells shown on Exhibit Number 3, what wells geologically are at the greatest risk of being affected by those wells that are producing in the violation area?

A. Obviously on this cross-section, the one that is at the greatest risk is Mewbourne's Number 1 "B" State. It has a relatively thin dolomite interval available to produce, and that same interval is being overproduced in the adjacent well to it, the Yates Number 3 Tackitt.

Otherwise, as you move on the other side of the cross-section, the Yates Number 2 and Number 3 Patriot wells are obviously being affected by the overproduction. They're completed in the same zones, and any pressure -- excessive pressure depletion that may occur due to overproduction, would have a detrimental effect on those flanking wells as well.

Q. Are you ready to turn to the next cross-section?

A. Sure.

Q. Let's look at Exhibit 4.

A. Exhibit Number 4 is similar, except that in this one, we're running from the Patriot Number 5, at the northeast end, through the violation area and into Conoco's acreage at the southwest end, or the left-hand side of the cross-section.

So that we begin in the cross-section at the left-hand side with the Number 5 Patriot. The Number 2 Hinkle lies within that area, the Number 1 Hinkle, and the Yates Number 3 State "K" are all violation wells. And then as we move to the right, we enter Conoco's acreage, the Number 1 Savannah, which is in compliance.

Again, we see a similar relationship as we're moving to the flanking edge of the field. In this case, instead of encountering limestone stringers, we're encountering shale stringers, which limit the amount of reservoir available to us.

In the case of the Conoco's Savannah, we do have a localized thickening of that upper zone, but still it's a limited zone that's being produced in this area. In this case it's approximately 50 to 60 feet thick, and we're pulling amounts of oil in violation out of that 60-foot zone, and I contend that that is detrimentally affecting the correlative rights of the offset operators.

Q. Are you ready to look at the next display?
A. The next one --
Q. I believe that's the end of yours, isn't it?
A. Yeah, that is.
Q. Summarize for us your concerns as a geologist

with regards to the issues that are before the Division Examiner today.

A. My concerns are that although we do see the ability of these wells to make phenomenally high rates, at the same time we're seeing the reservoir thickness decrease in this violation area.

I would contend that the reason we're seeing these high rates sustain is because we're not yet on 40-acre development, that these wells in violation are draining very large areas, and that they are prematurely depleting not only the acreage that they drain, but the adjacent acreage that is operating under the prescribed pool regulations.

MR. KELLAHIN: That concludes my examination of Mr. Hardie.

We move the introduction of his Exhibits 1 through 4.

MR. CARR: No objection.

EXAMINER STOGNER: Exhibits 1 through 4 will be admitted into evidence.

Thank you, Mr. Kellahin.

Mr. Carr, your witness.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Hardie, you've studied the Dagger Draw area for years, have you not?

A. Yes, I have.

Q. In fact, because of Conoco's interests in the area, Conoco has had geologists and engineers monitoring the development of this reservoir. Fair statement?

A. Yes, we do.

Q. This has become a reservoir that continues to grow, isn't it? The more we know, there seem to be more things to discover? Is that a fair statement?

A. That's absolutely correct.

Q. It's not a simple reservoir?

A. It's one of the most complex that I have encountered.

Q. When we look at the reservoir, we're really not looking at a homogeneous reservoir, are we?

A. No, we're not.

Q. We have multiple porosities, do we not? Matrix and vugs and fractures and almost everything you could hope to find, here it is?

A. That's been well documented, yes.

Q. And your study so far has focused, at least for presentation here today, on the North Dagger Draw; is that right?

A. What I've shown so far is strictly North Dagger Draw.

Q. You are preparing also a study on the South Dagger Draw?

A. Yes.

Q. I mean, basically, you've studied this for years. Are you anticipating that you're going to see something dramatically different in South Dagger Draw?

A. Very much so.

Q. So what we have here is a common, perhaps, formation that there are irregularities in it as you move -- or differences as you move from one portion of it to another?

A. Very significant differences, yes.

Q. Now, in your study, are you comfortable telling the Commission that there is a -- or are you trying to state that there is a real correlation between reservoir thickness and reservoir quality?

A. That is a natural relationship. The more reservoir thickness you have, that increases reservoir --

Q. So as you --

A. -- potential, the potential to produce more reserves.

Q. As you go about your study here, are you assuming that the thicker the section, the more you're going to be able to recover; is that a --

A. All other things being equal, that is correct.

Q. And what do you mean by "all other things being equal"?

A. All of the --

Q. Are you assuming for that a homogeneous zone?

A. No, I'm not. This is not a homogeneous reservoir.

Q. So even in a heterogeneous area, you're saying that thickness and quality are positive correlations?

A. No, that is not -- What I'm saying is that if your porosity and permeability is the same, then thickness is important.

Q. If they are the same?

A. That is correct.

Q. And yet in this reservoir they're not necessarily the same?

A. No, they're not, there's no question that in the violation area, although you have thinner reservoir, there is higher porosity and obviously greater permeability. Those are the three components that determine not only the rate that a well produced, but also the ultimate reserves.

I would contend, however, that if all you had is higher permeability, that just means you're going to get those reserves quicker, that at some point that flat-line production curve that you see in these high-rate wells is going to drop very dramatically.

Q. Is it your testimony that in the area that's overproduced, you find a homogeneous reservoir in that area?

A. No.

Q. Do you find common porosity throughout that area?

A. The porosity varies as you move laterally along any part of the field.

Q. When porosity varies laterally, even through this area, it would affect the amount that can be recovered well by well; is that not true?

A. That is correct.

Q. And when you make a general statement that because of what you see in the reservoir, correlative rights are being impaired, you would also have to know what can be withdrawn from that reservoir; isn't that true?

A. That is correct, that's one of the --

Q. And --

MR. KELLAHIN: Let him finish his answer, Mr. Carr, if you please.

THE WITNESS: One of the reasons that we feel a volumetric calculation across this area is of ultimate importance in determining whether or not the allowable violations are causing damage to the point where these wells need to be shut in.

Q. (By Mr. Carr) So you're saying additional study is needed?

A. Absolutely, and that's what we requested, beginning before this hearing began.

Q. And when you say the correlative rights are being adversely affected, that is conditioned on what you may learn in an additional study?

A. That is correct, but everything that we've seen so far indicates that the correlative rights are being violated.

Q. But my question was --

A. The quick look that we have taken to this point indicates that there's a strong chance that correlative rights are being violated.

Q. But my question was -- if you'll answer the question that I asked, then we'll get through this -- my question was, before you know, you think additional study is needed?

A. Before we can quantify the amount of drainage that's occurred and the amount of violation of correlative rights, we need to do additional study.

Q. Are you assuming up front that there's a violation of correlative rights before this study is undertaken?

A. I'm telling you that all the evidence I've seen to date in the short period of time that I've been able to look at the new well data available and the production curves, that it's very likely, strongly likely that a violation of correlative rights has occurred.

Q. My question was, before you can say there's a correlative-rights violation, is more study needed?

A. I say there is more study needed to determine the amount of violation that has occurred.

Q. Okay. But you can say today that there's a violation occurring?

A. I can say that with a 90-percent certainty there is a violation occurring. Before I come to State proclaiming the amount of violation that has occurred, the amount of reserves that have been withdrawn from Conoco's acreage illegally, I think there's more study that needs to be done.

Q. And so when you make your statement here that there's a correlative-rights problem, you still think it needs to be further refined with some additional work?

A. That is correct.

Q. And if you're -- we happen to have the 10-percent situation because of porosity variations, then next time you would reserve the right to amend that position; is that right?

A. I'm not making any comments now as to the amount of reserves that have been drained from the adjacent acreage.

Q. Wouldn't you need to know that before you can really make a statement on --

A. Absolutely.

Q. -- correlative rights violations?

A. Well, I need to know that before I can come to the State and proclaim that X amount of reserves have been drained from our acreage illegally.

Q. And you need to know that before you can come in here and just proclaim that there are serious correlative-rights violations?

A. I can tell you that the initial look at the data that we have performed indicates there's a very strong possibility that correlative rights have been violated.

Q. I just want to know if you've reached your conclusion before you do the study or if you need to make the study. That's the question.

MR. KELLAHIN: I'm going to object, Mr. Examiner. Mr. Carr has asked the same question five times now, he's got the same answer back. I don't share his confusion over the answer. I think we're beyond this point at this time.

MR. CARR: My question is very simple, and if I could get it answered I wouldn't have to ask it again.

MR. KELLAHIN: He's arguing with the witness.

MR. CARR: The question is --

MR. KELLAHIN: He's had his answer.

MR. CARR: Mr. Kellahin, I'm explaining this to the Examiner, this is not the form of a question. Some of us ask questions, some of us narrate. I'm trying to ask a question.

Q. (By Mr. Carr) I'd like to have an answer as to whether or not additional study is needed before we can make the bald assertion that there's a correlative rights that needs OCD intervention, and the answer can be yes and the answer can be no.

MR. KELLAHIN: That's a argumentative question, and I object to the form.

EXAMINER STOGNER: Let's move on, Mr. Carr.

Q. (By Mr. Carr) Are you intending to conduct additional study if in fact the case is continued?

A. I am expecting to conduct continuing study, whether or not the case is continued. This is a matter of great concern to Conoco management.

When you look at the amounts of reserves that have been pulled adjacent to our acreage in excess of the allowable, it amounts to almost a quarter of a million barrels of oil, and they, I'm sure --

Q. Have you calculated that?

A. That is just the amount of excess oil that has been produced in the proration units adjacent to Conoco's acreage.

Q. And was it your testimony that that has been drained from that quarter million --

A. That is the amount that has been produced in excess --

Q. Okay.

A. -- and the additional study would ultimately attempt to conclude how much of that has come from Conoco's acreage.

Q. Now, Mr. Hardie, my question was, between now and when we hear this again, if there is another hearing, whether or not you intend to do additional study. And I understand your answer to have been yes; is that right?

A. That is correct.

Q. And it's also my understanding that when you said that there had been a quarter of a million barrels withdrawn from this area, that you were not saying that that had all been drained from Conoco acreage; is that right?

A. I'm saying that's the amount that's in excess of the allowable, and that a portion of that has likely come from Conoco's acreage.

Q. You're not saying that a million, or whatever number, has all come from Conoco's acreage?

A. That will be determined upon further study.

MR. CARR: That's all I have.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Padilla?

MR. PADILLA: I don't have any questions.

EXAMINER STOGNER: Mr. Kendrick?

MR. KENDRICK: I have no questions.

EXAMINER STOGNER: Mr. Bruce?

MR. BRUCE: No, sir.

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Any redirect?

MR. KELLAHIN: No.

EXAMINATION

BY EXAMINER STOGNER:

Q. When I look at your cross-section, the little dotted red line, again, what is that?

A. That is a datum that is set at a subsurface elevation of minus 4300 feet.

Q. So it's just an arbitrary line that --

A. It's somewhat --

Q. Somewhat arbitrary, but --

A. Somewhat arbitrary. It's very unlikely that you would find oil reserves below that line.

Q. That's just a line, but it really doesn't depict any kind of geological change?

A. No, it does not.

EXAMINER STOGNER: Okay, you may be excused.

Mr. Kellahin?

ROBERT E. BEAMER,

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. Beamer, for the record, sir, would you please state your name and occupation?

A. My name is Robert E. Beamer. I'm a petroleum engineer for Conoco, Incorporated, Midland, Texas.

Q. Mr. Beamer, on prior occasions have you testified before the Division and qualified as a petroleum engineer?

A. Yes, I have.

Q. Have you compiled information with regards to the data available to you concerning those wells producing in the North Dagger Draw in what Mr. Hardie characterized to be the violation area?

A. Yes, I have, and it's summarized on Exhibit 5.

Q. All right. At this point, sir, have you been able to conduct and complete a reservoir study with regards to the impact that the overproduction in the violation area may have had on adjoining Conoco-operated spacing units in the same pool?

A. No, I have not had time to do that.

MR. KELLAHIN: All right, sir. We tender Mr. Beamer as an expert petroleum engineer.

MR. CARR: No objection.

EXAMINER STOGNER: Mr. Beamer is so qualified.

Q. (By Mr. Kellahin) Let's turn to Exhibit 5, sir. Exhibit 5 represents what?

A. Well, this is a blown-up section of the maps that were shown earlier as Exhibits 1 and 2, with the violating proration units outlined in red, which should -- which would correspond to that same outline on the previous Exhibits 1 and 2.

Q. All right. So when we look at Exhibit 5 -- and let's start up in the northwest of 21 -- that spacing unit is labeled or identified with the number 1?

A. We've -- We're using that as a reference number, which we'll tie to other exhibits that we'll talk about.

Q. All right. We're going to show Exhibit Number 6 here, and that number, then, ties back in to that exhibit, so let's do this together. If you'll start with Exhibit 5, let's also go to Exhibit 6 --

A. Yes, sir.

Q. -- and we'll look at them together.

A. Okay.

Q. When you look at Exhibit 5, and our example is the northwest quarter of 21, it's identified as Yates. What does that mean, then, to you? Is that a Yates-operated spacing --

A. The operator of the northwest quarter of that section is Yates Petroleum.

Q. All right. Below the name, then, is the number 7594. What does that mean?

A. That's my calculated amount of overproduction for this particular proration unit, which --

Q. And then below that is a date. It says 2-1 of 1996. What does that mean?

A. That's the effective date for which I had production data.

Q. All right. Within that spacing unit, you've got a color-code identifying four wells, and you've named all four wells. What is the color code?

A. Well, the black wells are older developed wells. I believe Bill has commented on the color code.

Q. So you've used the same color code as Mr. Hardie, then?

A. Yes, I have.

Q. All right, let's take Exhibit 6, now, and turn to the first page of Exhibit 6, and find the first numbered spacing unit, Number 1, and this equates to the northwest of 21, right?

A. Yes.

Q. All right. When we look at the tabulation, what is the source of the tabulation of the data shown on Exhibit Number 6?

A. The source is either from *Dwight's* historic database or from data supplied by Yates Petroleum for months -- October of 1995 through the current available month of February, 1996.

Q. All right.

A. And then I combined the two data sources into a spreadsheet to compute the over- or under-balance situation.

Q. All right. Let's see how you've organized the spreadsheet. If you start on the first row and read from left to right, you've got the spacing unit identified by an acreage. The next column over is the month by production, and then you have oil, gas, water. And it shows wells; I assume that's the number of wells in the spacing unit at that time?

A. That we're producing at that time, yes, sir.

Q. And then the next column is allowable. That allowable is what, sir? How do you get that calculation?

A. That's 700 barrels a day, times the number of producing days in a month.

Q. All right. And then the last column on the far right is a number with a minus in front of it. What does the minus signify?

A. For that particular month, that proration unit produced 13,389 barrels less than the allowable.

Q. All right. So it's an over/under calculation?

A. It's simply the oil barrels produced, which are shown under oil, less the allowable.

Q. Okay. And as we read down, then, the far right column, that spacing unit has not exceeded its allowable until we look at the shaded area you've shown on the spreadsheet?

A. The shaded area, plus I have bolded the overproduction numbers so that they would be -- they would stand out from the underproduction.

Q. All right.

A. And then carrying from that first month of violation forward, then I have added through the current data available, to arrive at a sum overbalance production for this particular unit of 7594 barrels.

Q. All right. When you go to the shaded area on this display and look at the row just above the first arrow, and we're looking at -- What's that? June of 1995?

A. Yes.

Q. And you read across and you find that the operator, Yates, has now added a second well to that spacing unit --

A. Yes.

Q. -- and then we move into the shaded area, and the two wells in combination, then, for that period as shown as overproduction?

A. Yes.

Q. All right.

A. And then on the back of this Exhibit 6 --

Q. Let's turn to the back of Exhibit 6, then, and look at the back of the first page. What have you shown on the back of the first page?

A. Well, that's a plot of the data presented in the table on a daily basis.

Q. All right. So we can look to the back of each of these tables in Exhibit 6, and we can see the oil plot and the water plot and the gas plot?

A. Yes.

Q. All right. Have you gone through the same method for each of the 13 spacing units that are shown identified on Exhibit 5 as within the violation areas?

A. Yes, I have, and they're identified as Exhibits 6 through 18.

Q. So as we go through the binder of exhibits, after Exhibit 6, you've numbered 7 through 19 --

A. Through 18.

Q. -- 18, and each one of those, then, pertains to a specific spacing unit?

A. That's correct.

Q. All right. Let's go to Exhibit 9 and look at that as an example for the production on the Yates-operated spacing unit in the northwest quarter of 29.

A. Yes.

Q. Take us down in a summary and a brief fashion and show us what's happened as they've added wells and how they've handled that management of well production in relationship to the allowable.

A. Well, they were under the allowable restriction, through October of 1993, at which time a third well was completed, which I believe was the Voight Number 3.

At that time, they went into an overproduction situation, which carried forward through August of 1994, and I think probably the production plot would show this maybe more easily.

You can see how the new wells peak in production and then decline to a point at which they fall below the allowable production, at which time, then, the operator would drill and complete an additional well. The total proration unit production would exceed allowable rates, which are identified by the solid black line, until decline occurred to the point where they fell below the allowable situation and the fourth well in this particular proration unit was added.

Currently, that spacing unit is no longer capable, from the appearance of this plot, of meeting its allowable production.

Q. Let's turn to Exhibit 12, then, and look at spacing unit number 7. It's going to be the southeast quarter of 29.

A. Yes, sir.

Q. As we move down into May of 1995 on that table, Yates has got two wells operating, and that spacing unit's overproduced its allowable? Is that the way you read this?

A. In May of 1995 a second well was completed, the Boyd Number 6, which put the spacing unit into an overproduction situation, and that has carried forward through this most recent month of data that I have of February, 1996.

Q. All right. Look at the data point for the row that's identified as November of 1995 on Exhibit Number 12.

A. Yes.

Q. They have two wells in the spacing unit, the spacing unit has overproduced its allowable, and yet they add a third well in December, and the overproduction is increased.

A. Yes, the Boyd Number 5 was added in December of

1995. And from the production plot, it's apparent that they are right -- are currently at allowable limits, and probably for these three wells would decline below that.

Q. Let's turn to the last page of this binder, if you will -- it's Exhibit Number 19 -- and have you explain what you've done with this exhibit.

A. This is, very simply, just a summary of each of the proration unit overbalance situations, totaling -- And again let me explain. The map reference number refers to the numbers in blue on the Exhibit 5 map, identified then by quarter section, and then showing the cumulative overproduction situation, for the Yates data it's through February, 1996, and for the Nearburg units, they provided data through March of 1996.

Simply a summary of the data, showing the Yates overproduction, my estimate of about 988,000 barrels of oil, and the Nearburg units of about 165,000 barrels of oil.

Q. Turning to Exhibit 20, identify and describe what you've tabulated for the Examiner on Exhibit 20. And that would be -- that's a separate exhibit set, is it not?

A. Yes, it is. I did the same type of calculation for the Conoco-operated units that are affected here, both occurring in the north half of Section 32.

The northeast of Section 32, our Savannah State

Number 1 well, which was completed in September of 1995, we show, has never exceeded allowable rates.

In the northwest section of 32, the first month of production for our Joyce Federal Number 1 well did exceed allowable rates by 2800 barrels, but natural decline since then has eliminated that overproduction situation, and our wells are not capable of meeting allowable rates at this time.

Q. As a reservoir engineer, have you studied the Dagger Draw prior to examining the overproduction issue that's presented to the Division today?

A. Yes, I've been involved with Dagger Draw production, now, for about a year and a half.

Q. All right. Describe for me, from your perspective as a reservoir engineer, the concerns that you have for your company concerning the excess fluid production that's occurred in the violation area and whether or not that has a probability of giving Yates and Nearburg any type of unfair competitive advantage in recovering the reserves out of the pool.

A. Well, I look at this reservoir as essentially a closed system. Pressure depletion will occur as a result of fluid withdrawals in these offending leases, by overproducing them significantly, 1.1 million barrels. That's oil only. When you consider barrels of water and the gas associated with it, we're probably looking at four barrels of additional reservoir fluid for every barrel of oil produced.

That's a significant effect on pressure depletion, and I'm suggesting that that overproduction probably has caused a pressure sink in their favor. In other words, would tend to have fluids migrate from nonoffending leases to the pressure sink.

Q. Do you have any comments or concerns about Yates' recommended allowable increase for the North Dagger Draw of taking that oil allowable from 700 barrels a day per spacing unit, up to the 4000 barrels of oil per day?

A. Well, my -- Of course, my first concern is that it's based on probably the best well in the field. I'm not convinced that if that southwest quarter section of 28 were developed completely on 40-acre spacing, that that well or any successive wells in that section could ever approach that rate per well. I think it's a little excessive.

Q. At this point, if the Division were to adopt a 4000-barrel-of-oil-per-day allowable, this pool would be unrestricted as to an oil allowable, would it not?

A. I think it essentially would be unrestricted, yes.

Q. Do you have a recommendation yet as to what Conoco proposes as the allowable level for this pool?

A. At this time, no.

Q. Describe for me why you are here today as a reservoir engineer, Mr. Beamer, and what concerns that you have on behalf of your company concerning this Application.

A. Our concern is that we're in a competitive reservoir, a regulated competitive reservoir. All parties have not been playing by the same rules, and it is possible that we have had some drainage, and our management is concerned that the regulations be applied uniformly and that any allowable increase that might result as a matter of these hearings be deferred from these particular proration units until the overbalanced situations are corrected.

Q. Based upon your knowledge up to this point -- you've heard Mr. Fant's testimony -- do you think that reserves would be lost if these offending units' production were shut in until the overbalance is made up?

A. Total field reserves?

Q. For the violating spacing units, just shut them in?

A. I think from my past analysis of North Dagger Draw -- and I haven't had an opportunity yet to go through an interference-type analysis similar to what Bob has presented this morning, but I think it's highly likely that wells in North Dagger Draw will drain or can drain in excess of 40 acres. It's possible, yes, by shutting in wells for a prolonged period of time, that some drainage could occur.

On the other hand, some of the excess production produced to date may already have been produced from other than the wells' particular 40-acre drainage radius.

Q. Is your company in favor of or in opposition to canceling the overproduction in the violation area?

A. We're in opposition to that.

MR. KELLAHIN: I have no further questions of Mr. Beamer.

We move the introduction of his exhibits. They are marked 5 through 20.

EXAMINER STOGNER: Any objection?

MR. CARR: No objection.

EXAMINER STOGNER: 5 through 20 will be admitted into evidence.

Thank you, Mr. Kellahin.

Mr. Carr, your witness?

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Beamer, are you the engineer in charge now of Dagger Draw for Conoco?

A. As far as the reservoir engineering aspects are concerned, yes.

Q. And did you tell me that you've been working on the project for about a year and a half?

A. Yes, roughly a year and a half.

Q. Is it your primary assignment, or do you have other things you're also looking at for Conoco?

A. I have other responsibilities.

Q. In terms of your responsibilities for Conoco as it relates to this reservoir, is it important for you to stay abreast of what's actually going on, on the tracts, not just Conoco, but all tracts in the reservoir?

A. We try to stay abreast, yes.

Q. If I look at your exhibits, it appears that Conoco has an interest in overproduced tracts 1, 2, 3, 5, 8 and 9.

A. Yes.

Q. Were you aware that those tracts were overproduced?

A. I cannot say that I was aware of the overproduction until I started looking at data specifically for this hearing.

Q. And so in terms of the way Conoco is monitoring the reservoir, you weren't really aware that there were wells substantially or -- substantially overproduced --

A. I wasn't aware of any significant violations until we began preparing.

Q. And there were no complaints to Yates or other operators about these production practices by Conoco?

A. No.

Q. If I understood your testimony, there are a number of things that you really ought to take a look at before you can make a real informed call on what needs to be done with the reservoir; is that fair to say?

A. Yes.

Q. You need to look at pressure depletion or study that. Was that one of the things you mentioned?

A. Yeah, and that's going to be qualitative, I think.

Q. How much time does it take, now, I mean being realistic, for you to make these studies?

A. I will have to rely on a technique similar to what Bob has done in looking at the effect of offsetting wells on existing oil production, and that does require time to establish changes in decline rates.

Q. In terms of any recommended change in allowable rate, that's something that also needs additional study in terms of what Conoco is prepared to recommend; is that fair to say?

A. I think so, yes.

Q. And you were concerned that what's being recommended right now is in fact trying to set the allowable based on the best well in the pool, so it would be an unrestricted from an oil production --

A. In my opinion, it would be.

Q. Are you aware of what considerations came into play back when the 700 allowable was set?

A. Well, obviously I wasn't involved with it, and my recall on that is not good enough to discuss it right now, but --

Q. You don't know whether or not at that time 700 was believed to be what a well -- I mean, setting it at a rate that wouldn't restrict the oil?

A. I don't know what the basis of that was.

Q. Would you agree with me that in terms of managing this reservoir, producing oil cuts is an important thing to try and achieve, from a waste point of view?

A. I understand -- Yes.

Q. And that trying to, while you produce the reservoir, to hold down the gas-oil ratio also is an important thing in terms of efficient production of the reserves under there?

A. Yes, I understand that. I need some time to evaluate this data that's been presented, yes.

Q. But it is important to try and keep the gas-oil ratio down to maximize your recovery, generally speaking, is it not?

A. Yes, yes.

Q. It was Conoco's recommendation, if I understood you, that any change in special pool rules be deferred until after production is made up, till the overproduced wells are back in line; is that right?

A. Yes.

Q. Wouldn't you think it would be important to go ahead and look at an allowable change if, in fact, it would take oil cuts down and keep gas-oil ratio -- oil cuts up, gas-oil ratios down, independent of whether or not some wells are overproduced or not, or otherwise?

A. I'm not convinced that the ultimate recovery from this pool will change.

Q. Have you studied that?

A. No, but based on my knowledge and understanding of this type of pool, a closed system, not supported by any aquifer, North Dagger Draw is not supported, really by any gas cap, this -- I don't think there's any significant difference in ultimate recovery.

Q. Have you been involved as the engineer -- and I assume you have -- on what wells Conoco has drilled in this reservoir?

A. In recent -- In the last year and a half, yes.

Q. And some of those wells, when they come on, have they initially come on at a rate above the allowable and then experienced a fairly rapid decline?

A. Unfortunately, that's true.

Q. So for short periods of time they have been overproduced?

A. Yes. In fact, it's summarized on Exhibit 20.

Q. And my question is, when we talk about making up overproduction, you're saying nothing should be done on allowable until Yates gets back into line on these wells; is that what you're saying?

A. Or Yates or Nearburg.

Q. Or Marathon?

A. Well, Marathon doesn't operate in this North Dagger Draw.

Q. But in South Dagger Draw, you would make that recommendation, would you not --

A. Yes.

Q. -- for everything?

A. Yes.

Q. And you're making that recommendation irregardless of what the data shows about what's needed to efficiently change -- to change these rules to efficiently produce the reservoir?

A. Yes, because I don't believe that the ultimate recovery from the reservoir is going to be appreciably different.

MR. CARR: That's all I have. Thank you, Mr. Beamer.

EXAMINER STOGNER: Mr. Padilla?

MR. PADILLA: I don't have any questions.

EXAMINER STOGNER: Mr. Kendrick?

MR. KENDRICK: I don't have any questions.

EXAMINER STOGNER: Mr. Bruce?

MR. BRUCE: No, sir.

EXAMINER STOGNER: No questions. Mr. Carroll?

MR. CARROLL: No, sir.

EXAMINATION

BY EXAMINER STOGNER:

Q. In the tabulation of your Exhibits 6 through 19, this was taken off the *Dwight's* or information supplied to you by Yates?

A. By either Yates or Nearburg, that's right.

Q. Yates or Nearburg.

A. Yes.

A. Of the information that was supplied by Yates or Nearburg, what form was that?

A. Yates sent me a floppy of the digital data, which I then downloaded into a spreadsheet.

Nearburg fax'd me a hard copy record of their monthly production from October of 1995, for their wells operated in Section 27.

Q. Now, were you aware or do you know if that information that Nearburg and Yates supplied to you was the same information which they would supply on the C-115? That's the monthly production report.

A. It's my understanding that it is the same information.

Q. Now, you didn't include the casinghead gas allowable. Did you omit that because there is no overproduction in the casinghead gas allowable?

A. I'm not aware of any overproduction on the gas.

Q. Okay.

A. I believe these units have a GOR restriction of 10,000 to 1, and I think that the production plots will show that the gas rates are nowhere near the allowable rates.

Q. Okay. Now, going back to the GOR limit at this point --

A. Yes.

Q. -- the study that you're proposing, would you also -- are you recommending that we review, or at least the gas-oil ratio limitation be looked at also?

A. For South Dagger Draw, for South Dagger Draw specifically, yes.

Q. For South Dagger Draw, but not the North?

A. No, because I think it's a moot point.

Q. What is the difference between the two of them?
A. South Dagger Draw is affected by a significant gas cap, and we're concerned with excessive withdrawals from that gas cap, as it will affect a very thin oil leg.
Q. Are you responsible for the Conoco-operated wells in this area --
A. In what regard?
Q. Well, let me finish.
A. Okay, I'm sorry.
Q. -- of reviewing its production and make sure that they are kept within the limitations?
A. That's a combined effort. Primarily, our production engineer is the one who has typically been watching our production over/under situation.
We've recently changed production engineers, just within the past month, but I can comment on our Joyce Federal Number 1.
Q. Which one is that?
A. That's in the northwest quarter of Section 32. That's the first well that Conoco has drilled in this newly developed area, followed, then, by the Joyce 2 and the Savannah State Number 1 well, which was the better of our three wells, as far as IP. Our production engineer was very concerned that we were about to exceed the monthly allowable rate on that well. It didn't, but we were

watching it on a daily basis, and he was corresponding with the field foreman in that regard.

Q. So in -- None of those wells that you just referred to in Section 32 had to be artificially restricted?

A. No, natural decline took care of any overproduction possibilities there.

Q. And you don't know of any -- there again, Conoco-operated wells -- any need to artificially restrict to keep in line with the allowable?

A. No, we wish we had the problem.

EXAMINER STOGNER: Okay, no other questions.

MR. KELLAHIN: That concludes our presentation, Mr. Examiner.

EXAMINER STOGNER: Mr. Padilla, do you have a presentation at this time?

MR. PADILLA: I don't.

EXAMINER STOGNER: Mr. Kendrick?

MR. KENDRICK: I do not.

EXAMINER STOGNER: Mr. Bruce?

MR. BRUCE: No, sir.

EXAMINER STOGNER: Do you have any redirect, or do you wish to recall anybody, Mr. Carr?

MR. CARR: No, Mr. Stogner, I do not.

EXAMINER STOGNER: Okay, Mr. Kellahin, do you propose to make your motion again at this time?

MR. KELLAHIN: I would renew my request, Mr. Examiner, that subject to your discretion, that if you desire to have Conoco present a reservoir-engineering presentation with regards to trying to quantify the magnitude of drainage, it will be a task to perform that we have not yet undertaken, and we would need time to do that.

If you don't think that information is necessary for deciding this matter, then we have nothing else to present.

(Off the record)

EXAMINER STOGNER: Mr. Carr?

MR. CARR: Sir?

EXAMINER STOGNER: Do you have any response?

MR. CARR: No, sir, I would just note that there is -- as you noted, when you ruled on this motion, that this is an important issue, that time is of the essence and that if there are continuances of this, we would hope it would not go beyond June of this year.

EXAMINER STOGNER: Mr. Kellahin, I believe I've heard enough in this case that any additional information -- wouldn't necessarily be a burden, but I believe enough information has been presented by both parties, that an adequate decision can be made.

So I'm going to at this time take this under advisement.

MR. KELLAHIN: I need to ask you how you would like us to handle the question of South Dagger Draw. We are concerned that the gas allowable, if calculated for South Dagger Draw, would result in an artificially too high gas limit of 56 million MCF a day, and we have our concerns about that topic.

If you would like me to address that issue before you take both cases under advisement, I might do that in just a few minutes with Mr. Beamer, and then you would have our point on that question.

EXAMINER STOGNER: If you feel that would be a responsible thing to do at this time, yes.

MR. KELLAHIN: All right, let me do that, sir.

EXAMINER STOGNER: How much time do you need?

MR. KELLAHIN: I can do it in just a few minutes. Stay up there, Bob.

(Off the record)

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER STOGNER: We're back on the record.

DIRECT EXAMINATION (Case No. 11,526)

BY MR. KELLAHIN:

Q. Mr. Beamer, I've handed to you, and I've provided to opposing counsel and to the Division, what are identified as Conoco exhibits for the South Dagger Case.

They are numbered Exhibits 1 through 21.

They include the geologic workup that Mr. Hardie has done, and I don't propose to call Mr. Hardie, but I've simply shared them with Counsel, and they may examine them if they desire.

A. Yes.

Q. I want to focus with you, sir, on the principal concern Conoco has in South Dagger Draw.

And if you'll take a moment, look at Exhibit 1, which is our locator map, Mr. Fant talked about the Diamond well in South Dagger Draw. It's in Section 34 of Township 20 South, Range 24 East. The proximity of that well is adjacent to Conoco-operated tracts in South Dagger Draw; is that not true?

A. Yes. And in fact, let me point out that this particular base map was constructed for a hearing presented here in September, 1995, so the well status code is not necessarily correct on this map.

The Diamond 1 well that Mr. Kellahin is referring to has been completed and should be so noted as a solid red dot.

Q. All right. When we turn to the package of documents marked 7 through 21, what is contained within that material?

A. Again, I'm presenting production data per proration unit, as defined in the South Dagger Draw field, and I have started these exhibits with the bottom half, or bottom row of sections in Township 20 South, Range 24 East, beginning with the Conoco-operated section in the proration unit occupying the east half of Section 34 and then going south through the rest of the South Dagger Draw field, outlined area.

Anyway, these, then, are production plots by proration unit, showing oil, water and gas production, as a function of time.

Q. You described a while ago, just before the break, that in South Dagger Draw you were concerned about the gas-oil ratio, and the ultimate gas allowable allowed for the wells in that pool, because in your opinion there was a thin oil leg and a very large or a big gas cap that you had to contend with. Is that a fair characterization of what you were describing?

A. Yes.

Q. All right.

A. The Indian Basin gas field is contiguous to this area and produces gas only from the updip limits of this reservoir.

Q. And the South Dagger Draw Pool we're looking at is designated as an associated oil and gas pool by the Division?

A. Yes, it does produce oil and associated gas.

Q. And the rules in South Dagger Draw are 320 spacing, currently 1400 barrels of oil a day per spacing unit, you've got a GOR of 7000 --

A. 7000 to 1.

Q. -- giving you a gas allowable of 9.8 million?

A. That's correct.

Q. All right. If the Division increases the oil allowable to 8000 barrels of oil in that pool, do you have any concerns about increasing the oil allowable to that level?

A. Well, we've already mentioned that assuming the GOR limit is retained, that it's 7000 to 1, that would allow gas withdrawals from this -- from any spacing unit to 56 million cubic feet a day, which we would oppose as being excessive, because that high a gas rate would probably come from the overlying gas cap.

Q. What's the current gas limit in the gas pool under the prorated Indian Basin-Upper Penn gas rules?

A. It's my understanding that that currently is regulated to 6.5 million cubic feet per day, per 640-acre spacing unit, which really creates quite an imbalance.

Q. Describe for us that concern at the Indian Basin Gas Pool -- and it's shown on Exhibit Number 1 -- as you move down to the west and south, you're getting into the gas cap, are you not?

A. Yes.

Q. All right. And the proximity of the western edge of South Dagger Draw and the eastern edge of Indian Basin creates an imbalance, then, between wells in one pool, having a 56-million-MCF gas allowable, and those spaced on 640 adjacent to that with only a gas allowable of 6.5 million a day?

A. Yes, it does.

Q. So summarize for us your problem.

A. Those high gas rate withdrawals will significantly affect pressure, and we are producing oil from that same reservoir system in our Preston Federal lease area, and also the Diamond Number 1 is completed in that zone. We think that excessive withdrawals and more rapid pressure decline will result in a waste of -- or a loss of oil reserves.

Q. What's your recommendation with regards to the gas allowable, then, with South Dagger Draw? What are you suggesting that we do?

A. Well, it's somewhat dependent upon an adjusted oil rate allowable. But we would contend, then, and in conversations with Marathon privately in Midland, it's their desire that gas limits be set at about 14 million cubic feet per day, which, if for any reason the oil allowable were set at 4000 a day per 320-acre spacing unit, would result in a limiting GOR of 3500 cubic feet per barrel. Again --

Q. Well, let's talk about that so no one is confused. If you make the calculation under the Yates proposal, your concern is the gas allowable limit becomes 56 million a day?

A. Well, that's right.

Q. And you have had conversations with Marathon where you are in agreement that if the allowable on the gas side does not exceed 14 million a day --

A. Yes.

Q. -- you are presently comfortable with that level?

A. That's right.

Q. And you have no opinion as to what to do to accomplish that in terms of adjusting the oil rate?

A. Not really. And to be honest, Marathon is really the operator to benefit or to not benefit from allowable changes in this pool. They are the major operator in this developing area of the field.

Conoco does have some additional development work to do, as does Yates, but it's apparent just from this map that Marathon operates the significantly underdeveloped area.

Q. When we look at South Dagger Draw at -- I guess one way to back into it, if it's 4000 barrels a day in South Dagger Draw, and you multiply that by 3500 GOR, you'll get the 14 million a day?

A. Yes.

Q. All right. Why are you so concerned about the oil-allowable rate in North Dagger Draw, and do not have the same level of concern as you move down towards the gas cap and move through South Dagger Draw?

A. I'm not suggesting I don't have the same level of concern. I don't have enough data at hand yet. Many of these wells are so new that established declines have not been set, and we haven't been able to evaluate these yet.

Besides this Diamond 1 well, there are some new Marathon wells, and also some new Yates wells on this Mojave lease in Section 35 of the -- 23 East, that we just haven't had time to evaluate, and in fact I don't think anybody has, to know what those performance curves are going to look like.

Q. I want to make sure I understand. With regards, then, to adjusting the allowables South Dagger Draw, it's your position that neither you nor anyone else has enough data yet to justify increases of the magnitude that Yates has requested in that pool?

A. That's my opinion.

Q. Do you have an opinion as to whether the oil rate in South Dagger Draw ought to be increased above the 1400 a day? Is there still not enough data on that issue?

A. I don't have enough data at hand to evaluate that.

MR. KELLAHIN: All right, sir.

Thank you, Mr. Examiner, that's all the questions I have of Mr. Beamer.

We would move the introduction of Exhibit 1, and then we would move the introduction of his plots, Exhibits 7 through 21.

MR. CARR: No objection.

EXAMINER STOGNER: Exhibit 1 and 7 through 21 in Case 11,526 will be admitted into evidence at this time.

And are you just putting the remainder of those in the record?

MR. KELLAHIN: No, sir, they can't be in the record; I haven't authenticated them. But I've given them to Counsel. If there's ever a need to look at them, they're there. I would ask that if you want to retain them that you not utilize them in making your decision, because I have not authenticated them with a geologist.

EXAMINER STOGNER: Okay, if that be the case, then when this proceeding is over today if you will recollect those --

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: Mr. Carr, your witness.

MR. CARR: Thank you, sir.

CROSS-EXAMINATION (Case No. 11,526)

BY MR. CARR:

Q. Mr. Beamer, you indicated that in conversations with Marathon, they were indicating that they desired an increase to 14 million per day for the gas allowable for this reservoir; is that what you said?

A. Yes.

Q. And did you say that you concurred with that?

A. We have no objection to that.

Q. Would that better serve efficient production of the hydrocarbons from the reservoir, in your opinion?

A. It's a better preservation of energy than an allowable increase to 56 million. It's a compromise.

Q. But you -- Would you recommend that, or do you just take no position on that?

A. Really, I take no position on that. We could concur with that, we would have no real problem with that.

Q. Do you have any idea of what sort of study or work has gone into developing that number?

A. No.

Q. Is it your recommendation in the South Dagger Draw, as it was in the North, that there be no changes in the pool rules, pending all wells being back -- the overproduced wells getting back into balance?

A. I think that should be the case, yes.

Q. Even if an increase in the gas production rate to 14 million a day would be in the best interests of producing the reservoir, you still think that action should be deferred until all the wells are back in balance?

A. I'm really not aware of an overbalanced situation in South Dagger Draw. I would have to look a little more closely at that. But yes.

Q. And in fairness to you, you really do need time to study this if you're going to be --

A. Oh, yes.

Q. -- asked to make sweeping conclusions about the reservoir?

A. Absolutely, yes.

MR. CARR: That's all I have.

EXAMINER STOGNER: Mr. Padilla, your witness.

MR. PADILLA: I don't have any questions.

EXAMINER STOGNER: Mr. Kendrick?

MR. KENDRICK: No questions.

EXAMINER STOGNER: Mr. Bruce?

MR. BRUCE: No questions.

MR. CARROLL: Pass.

EXAMINER STOGNER: I have no questions of this witness at this time -- or now, or any time.

MR. KELLAHIN: That concludes our presentation, Mr. Examiner.

EXAMINER STOGNER: Is there any need for closing statements?

MR. KELLAHIN: No, sir.

MR. CARR: No. I would note that, unlikely as this seems, Nearburg concurs with Yates.

EXAMINER STOGNER: I'm sorry, what was that?

(Laughter)

MR. CARR: I would like to note for the record that Nearburg Exploration Company concurs in this matter with Yates. They would like there to be no more than four wells -- there to be no more than four wells authorized per 160 spacing unit in North Dagger Draw, and that as to the overproduction they would hope there would be a reasonable way to make it up, if the Division feels it must be done, recognizing that while some units are overproduced, there are some immediately offsetting, operated by the same individuals, that are underproduced.

They do concur with the recommendation of Yates Petroleum Corporation.

(Off the record)

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: No, sir, I have nothing further.

EXAMINER STOGNER: Mr. Padilla?

MR. PADILLA: I don't have anything.

EXAMINER STOGNER: Mr. Kendrick?

MR. KENDRICK: Nothing further.

EXAMINER STOGNER: Mr. Bruce?

MR. BRUCE: No.

EXAMINER STOGNER: With that, then, both Cases 11,525 and 11,526 will be taken under advisement.

(Thereupon, these proceedings were concluded at 12:31 p.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case Nos 11525 and 11526 heard by me on 2 May 1996.

[signature], Examiner
Oil Conservation Division

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 May 14th, 1996.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998