NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date SEPTEMBER 18, 1996 Time: 8:00 A.M.

NAME	REPRESENTING	LOCATION
W. Kellahin	Kellahin & Kellahin	Santa Fe
Bob Fant	Yates Pet	Artesia NM
William F. Carr	Campbell, Carr, Berge & Sheridan	Santa Fe
Pinson McWhorter	Yates Pet	Artesia, NM
Brent May	"	"
Jerry Hoover	Conoco	Midland
Bob Beamer	"	"
Randy G Patterson	Yates Petroleum	Artesia
Ralph Moore	Newbourne Oil Co	Midland
Duke Roush	Nearburg Exploration Co	Midland
Roger Prucino	Scheuer, Yost & Patterson	Santa Fe
Ernest L. Padilla	Padilla Law Firm PA	SF
Leslie Naughton	Unit Petroleum	Tulsa
Edward Heald	" "	" "
Tim W. Gum	NMOCD	Artesia
Ned Kendrick	Montgomery & Andrews	Santa Fe
Rand Carroll	OCD	SFe

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NAME	REPRESENTING	LOCATION
Vic Lyon	Pro se	Santa Fe
Bill Hardie	Conoco	Midland
James T Jennings	Pro Se	Roswel
James Bruce	Hinkle Law Firm	SF
Bob Frank	Yates P.	
Michael Shearn	Independent	El Paso

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION 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)

REPORTER'S TRANSCRIPT OF PROCEEDINGS
COMMISSION HEARING

BEFORE: WILLIAM J. LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
JAMI BAILEY, COMMISSIONER

(Volume I)
September 18th, 1996
Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission, WILLIAM J. LEMAY, Chairman, on Wednesday, September 18th, 1996 (Volume I), 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.

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I N D E X

September 18th, 1996 (Volume I)
Commission Hearing
CASE NOS. 11,525 and 11,526 (Consolidated)

* * *

E X H I B I T S

* * *

A P P E A R A N C E S

FOR THE COMMISSION:

LYN S. HEBERT
Deputy General Counsel
Energy, Minerals and Natural Resources Department
2040 South Pacheco
Santa Fe, New Mexico 87505

FOR THE DIVISION:

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

FOR YATES PETROLEUM CORPORATION
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

FOR CONOCO, INC.:

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

(Continued...)

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

FOR MARATHON OIL COMPANY:

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

FOR JAMES T. JENNINGS:

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 MEWBOURNE OIL COMPANY
and UNIT PETROLEUM 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 8:25 a.m.:

CHAIRMAN LEMAY: We shall now call Case 11,525, the Application of Yates Petroleum Corporation for amendment of Special Pool Rules and Regulations for the North Dagger Draw-Upper Pennsylvanian Pool and for cancellation of overproduction, Eddy County, New Mexico, and consolidate that case, without objection, with Case 11,526, which is the Application of Yates Petroleum Corporation for amendment of Special Pool Rules and Regulations for the South Dagger Draw-Upper Pennsylvanian Pool and for the cancellation of overproduction.

Can I call for appearances in Cases Number 11,525 and 11,526?

MR. CARR: May it please the Commission, my name is William F. Carr with the Santa Fe law firm Campbell, Carr, Berge and Sheridan. I would like to enter my appearance in this case for Yates Petroleum Corporation and also enter an appearance for Nearburg Exploration Company.

(Off the record)

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin. We're appearing on behalf of Conoco, Inc., this morning, and I have two witnesses to be sworn.

At the appropriate time I'll have comments about liking these two cases. We're opposed to the consolidation, and I'll explain that when the time comes.

CHAIRMAN LEMAY: Fine, okay.

Mr. Kendrick?

MR. KENDRICK: Mr. Chairman, I'm Ned Kendrick with the Santa Fe firm Montgomery and Andrews, entering my appearance for Marathon Oil Company.

We're actually -- I guess we're entering an appearance in both cases if they're consolidated, but if they're separated we're just entering an appearance in 11,526, the South Dagger Draw case.

CHAIRMAN LEMAY: Okay.

Ernie?

MR. PADILLA: Mr. Chairman, my name is Ernest L. Padilla, Padilla Law Firm in Santa Fe, New Mexico, appearing for James T. Jennings.

CHAIRMAN LEMAY: For who?

MR. PADILLA: James T. Jennings.

CHAIRMAN LEMAY: For Jim Jennings?

MR. PADILLA: Yes, sir.

MR. BRUCE: Mr. Chairman, Jim Bruce from the Hinkle law firm in Santa Fe, and I'm here representing Mewbourne Oil Company and Unit Petroleum Company.

CHAIRMAN LEMAY: And who?

MR. BRUCE: Unit Petroleum.

CHAIRMAN LEMAY: Unit, U-n-i-t. Thank you, Mr. Bruce.

MR. CARROLL: May it please the Commission, my name is Rand Carroll, appearing on behalf of the Oil Conservation Division. I have no witnesses at this time.

CHAIRMAN LEMAY: Okay, thank you very much.

At this time I think we'll swear in the witnesses, then hear Mr. Kellahin's objection to consolidation.

Will those that are about to give testimony in these cases, separate or together, please stand and raise your right hands?

(Thereupon, the witnesses were sworn.)

CHAIRMAN LEMAY: Mr. Kellahin, do you want to tell us why you don't want these cases consolidated?

MR. KELLAHIN: Yes, sir. Perhaps I could expedite that by simply making my opening presentation to you. During the course of that I can describe for you our concerns about how the cases are linked, and then you can decide how you want us to make that presentation.

CHAIRMAN LEMAY: Okay. Just a point of clarification. Were these cases consolidated for purposes of testimony for the Division hearing?

MR. KELLAHIN: Yes, they were, Mr. Chairman.

MR. CARR: Mr. Chairman before we get into Mr. Kellahin's opening statement, I am the Applicant in the case and I really do have the right to go first, and I would like to do that.

And before we get into opening statements, there is another matter that I must bring to the Commission's attention.

Yesterday afternoon I received from the Division a copy of a letter from a Mr. Bob Ireland of Conoco, dated September the 9th. In what is reminiscent of tactics of Doyle Hartman, we have a rambling tirade in which this individual purports to know a great deal about this case, about the activities of Yates, about the activities of the OCD and Mr. Gum and about the law.

None of it is sworn testimony. The accusations are the kinds of accusations that must be responded to before they can be considered. An individual who makes comments like that has to come forward and take his oath and be subjected to cross-examination.

To suggest that the letter is not designed to affect the outcome of this case is absolutely ridiculous. The letter was addressed to you, Mr. LeMay. It was copied to Commissioner Bailey, it was copied to Commissioner Weiss, and to Jennifer Salisbury, the individual to whom two of you report.

If this is to be considered, we have to have a right to have Mr. Ireland here to cross-examine him, because our due-process rights are violated if that does not occur. And after he testifies, perhaps we would have to also have Mr. Gum before the body. We're not suggesting that is the appropriate thing to do.

What we are suggesting --

MR. KELLAHIN: Objection, Mr. Chairman.

MR. CARR: We are -- State your objection.

MR. KELLAHIN: Yes, sir. Point of procedure, Mr. Chairman. I'm aware of Mr. Ireland's letter. I did not write the letter. If Mr. Carr wants to have it introduced as evidence in this proceeding, we need to decide how to handle that. My understanding of the procedures here are that that letter is not evidence before you, and you simply disregard it. And yet Counsel wants to comment on the letter on the record. We need to clear up how to do that.

MR. CARR: I'm not suggesting, Mr. Chairman, that Mr. Kellahin wrote the letter. He wouldn't do that.

I am suggesting that the letter came from one of the parties. I am telling you that if it is included in the record, we have to do other things that we don't want to do, and I'm asking you on the record to declare that it will not be part of the record, it will not be considered.

CHAIRMAN LEMAY: Mr. Kellahin, is that your recommendation, that it not be part of the record and not considered?

MR. KELLAHIN: It is not part of the record, Mr. Chairman. It's not one of my exhibits. I don't propose to call Mr. Ireland. I read the letter. We will cover all the issues that Conoco feels appropriate in the appropriate way before this forum this morning, and perhaps this afternoon, but I think Mr. Carr is premature in suggesting that we need to debate the contents of the letter. They're not evidence before you.

MR. CARR: I'm not intending to debate the contents of the letter. If anything is premature, it is one of the parties trying to *ex parte* the Commission, and all we're asking is that when we go into this the field be level, we present our own cases with sworn testimony, and that this Commission simply declare they will not consider that letter.

CHAIRMAN LEMAY: So it's both your recommendations that we ignore the letter and not consider it in the case?

MR. KELLAHIN: Yes, sir.

(Off the record)

CHAIRMAN LEMAY: Okay, let the record reflect that this letter that came from Bob Ireland of Conoco, addressed to me with copies to both Commissioners and

Secretary Salisbury, that that not be considered in this case and be -- the *ex parte* communication, and will no longer be considered. It never was considered, and it won't be.

Will that satisfy you, Mr. Carr, and you, Mr. Kellahin?

MR. KELLAHIN: It was Mr. Carr's problem.

CHAIRMAN LEMAY: Fine. Well, it won't be considered, Mr. Carr.

MR. CARR: Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Oh, a note of clarification for the record. I don't think Commissioner Weiss reports to Secretary Salisbury. That is, he's with the Petroleum Recovery Research Center in Socorro, and Secretary --

MR. CARR: I understood he was designated to sit by her.

CHAIRMAN LEMAY: He's the Secretary's designee but does not report to her.

MR. CARR: I was concerned she would have questions that she would direct to her designee. But I appreciate your ruling.

May it please the Commission, the case before you raises some very important questions for the Commission to resolve. The answers to those questions are going to really determine how the North Dagger Draw-Upper

Pennsylvanian Pool and the South Dagger Draw-Upper Pennsylvanian Associated Pool are developed in the future. And as you know, these are the largest oil-producing pools in the State of New Mexico.

The answers to the questions that are presented to you today are also going to determine if the Oil Conservation Commission and Division will meet their responsibilities to prevent the waste of oil.

What we're dealing with is a very complicated reservoir, and I'll direct you to my map. Mr. Kellahin and I have the war of the maps going on. But what we've got is, we have one reservoir, and it was initially -- In the early Seventies, there were a couple of discoveries. But what we discovered as development occurred was, in fact, one reservoir, North Dagger Draw, South Dagger Draw and Indian Basin-Upper Penn. It is all basically one continuous reservoir that extends through this area.

The zones are continuous, but we're going to show you that the producing characteristics well by well may be very different.

As I noted, the pools were discovered in the early 1970s, and the operators and the Oil Conservation Division have been called on numerous times to revise and develop rules that will govern how this particular reservoir is developed. And it is because it is perhaps the most complicated oil reservoir ever in the State of New Mexico.

But one thing has always been known about this reservoir, that along with the production of oil, substantial volumes of water are produced. And it has long been understood that it is more efficient to produce this reservoir at high rates, because at high rates water cut drops, more oil is produced, and waste is prevented.

And that's also the reason that over the years the rules have been adopted and revised, basically to accommodate production from the better wells in the pool, because when they're curtailed waste does occur.

Initially, when wells were produced -- or drilled and produced in this reservoir, they came on at very high rates and quickly experienced very rapid production declines.

In 1995, however, certain wells in primarily the northern portion of the field -- they came on strong, but they did not experience the decline that had been typical of wells drilled earlier in the development of this reservoir.

A meeting occurred between representatives of Yates and the District Supervisor for the Artesia Office in mid-1995 concerning this phenomenon. At that meeting the problem was discussed, and the problem was not resolved.

And during 1995 and 1996, Yates and certain other operators continued to drill wells in the pool, produced at very high rates, did not experience the production decline that wells developed earlier in the life of the reservoir, and these wells became overproduced.

And as a result of this practice, a number of spacing units in the pool are substantially overproduced. Yates has a lot. The overproduction is over 900,000 barrels of oil.

The Division Supervisor and representatives of Yates met again in April of this year, and at that meeting Yates proposed to cut wells back on these units to the current allowable limit of 700 barrels of oil per day and also to immediately bring this matter to Santa Fe in the form of hearings to try and determine what could be done with this phenomenon in this reservoir.

Yates curtailed the wells, Yates filed the Applications and an Examiner hearing was scheduled for May 2nd, 1996.

On April 26th, Conoco filed its entry of appearance and requested a continuance of these cases, stating that it had not been provided adequate time to prepare for the hearing. Conoco requested that the Examiner hearing be continued to June 13, 1996.

Because of our agreement with Mr. Gum to bring these cases to Santa Fe as quickly as possible, we have responded to the request for the continuance, stating we did not object to it, but because of our agreement we could not concur in it.

On April 29th, the Division denied the request, would not let the case be rolled back to the June 13th because of the urgency of the issue presented. The case was heard May the 2nd and 3rd, and an order was not entered for 104 days. It came out August the 14th, 1996.

We've known that curtailing wells caused waste, and we will show you that during that 104 days while we waited for an order, over 21,000 barrels of oil that were recoverable May the 2nd became unrecoverable and were wasted.

The orders from the Division address two issues. The first one was the overproduction. And before the Examiner, Yates requested that the overproduction be canceled. It showed that waste would be caused by restricting the overproduced wells, and it presented evidence that correlative rights had not been violated by the overproduction.

Conoco opposed. Conoco argued that additional study was needed and expressed concerns that its correlative rights were and had been impaired.

The Division ruled by denying the request to cancel the overproduction, by reducing the allowables for the overproduced units to 350 barrels a day. They cut the allowable for these units by 50 percent. They required that all spacing units be brought back into balance within 18 months. And they required monthly reporting on progress by the operators of those overproduced units, progress reported to the Artesia office, showing monthly what they were doing to get the wells back into balance.

The Division also denied the request to increase the allowables in these pools. That was the second question presented and addressed by those orders.

Instead of ruling on the technical data at that hearing, and although we presented data from over 280 wells that had been accumulated for a period of over 25 years, the Division dismissed the arguments as premature.

The Division did not exercise its expertise and competence in oil and gas matters, in engineering matters, in matters related to geology, but instead decided to form a committee of operators and to tell that committee that they should study the pool for 18 months and come back then and report and recommend changes in the rules. They also said that if when we came back in 18 months, we didn't basically have a unanimous agreement, they stated they would not change the rules.

Faced with this, faced with what we believe is compelling evidence that in the 104 days, 21,000 barrels of oil were wasted, we filed for a *de novo* hearing.

The same day we filed for *de novo* hearing, we sought a stay of the orders pending this hearing and an opportunity for you to review these questions. And the stay was granted. And even though the stay was granted, we have curtailed our wells and we are producing them now at a 350-barrel-a-day limit, the limit imposed by the Division Order.

At the hearing today we're going to call three witnesses. Randy Patterson is the Secretary of Yates Petroleum Corporation, and he's going to review the historical development of the rules for the pool, and he's then going to make recommendations as to how the Commission should deal with the current overproduction.

We'll call Brent May, a geologist. He'll review generally the geology of the reservoir, and he's going to show you that as we move across the field, even though you can correlate zones well by well, that there's a compartmentalization of the reservoir that you can see from a geologic point of view that affects how wells produce.

And finally we'll call Robert S. Fant, the petroleum engineer who's primarily responsible for Dagger Draw development for Yates, and he's going to present the results of the engineering work that Yates has done over the years to try and understand this complicated reservoir. He's going to make recommendations to you for increases in the allowables for these pools. And he's going to show you that without a substantial increase in the allowables, waste, substantial waste, is going to occur.

I would reserve the right to respond to the request not to continue the cases until after Mr. Kellahin's opening.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

Mr. Carr's display shows you part of the relationship in this dolomite reservoir. It's a long fairway. The reservoir has been managed with three separate sets of pools and their pool rules.

The little bump in the contour here, occurring in the separation between the two townships, this is the approximate southern limit of North Dagger Draw. When you get down below that area, you're in South Dagger Draw, which is a transition area into Indian Basin-Upper Penn. And when we come before the Commission every six months and talk about the prorated gas allowable for Indian Basin, this is what we're talking about, down here in the southern unit.

You're going to hear testimony from the various witnesses about what we've characterized a violation area. That violation area occurred in North Dagger Draw. Over on the eastern flank there are about six sections involved over in this violation area. I have reproduced the violation area on my display, and I'll describe that for you in a moment.

While the geologists are in agreement that this is a continuous dolomite fairway, where geologically you can see the continuity of the reservoir, the storage of fluids is substantially different.

North Dagger Draw is an oil pool. It makes substantial amounts of water. The testimony is that this is not an active water drive, simply pressure depletion. But in doing so, you produce lots of water.

You get into the transition area in South Dagger Draw, and there is a very thin oil rim and, depending upon how you make those completions in the transition area in South Dagger Draw, you may get a gas well or an oil well.

And when you get down into South Dagger Draw and -- I'm sorry, Indian Basin, and you get into the gas cap.

Let me describe for you how the rules, then, have been handled up to now.

In North Dagger Draw we have 160-acre oil spacing. The spacing allowable is 700 barrels of oil a day for the 160 acres. Operators are permitted to drill additional wells, other than one. Some operators have chosen to drill as many as four.

And as a result of drilling as many as four per 160, there is competition that occurred commencing in March of 1995 between Yates and Nearburg, where we contend an excessive number of wells were drilled. And the manner of producing those wells caused those operators, particularly Yates, to overproduce the oil allowables significantly. The evidence will show that that number is more than a million barrels of oil.

So one of the issues for you to resolve is the accountability for failure to comply with the Division rules. It's a significant violation, and you have to decide what happens.

The gas-oil ratio in North Dagger Draw is -- 10,000 to 1, is it? I think it is. The gas-oil ratio in North Dagger Draw is 10,000 to 1. And so the spacing units, the 160 acres, can produce 7 million MCF a day.

When you get down into South Dagger Draw, the transition area, those rules provide for 320-acre spacing units. The oil allowable is 1400 barrels of oil a day for the 320. And there is a 7000-to-1 GOR limit in the pool, which allows those spacing units to produce a maximum gas allowable of 9.8 million MCF a day.

When you get down to Indian Basin, the proration system down there is such that those wells are on 640 gas spacing and their current allowable is, I think, 6.5 million a day.

The competition that occurred in North Dagger Draw between Yates and Nearburg has caused substantial overproduction. My display here, which I think is Conoco Exhibit Number 6 -- We'll have copies for all of you when it's our turn to present. But it will show that for each of the numbered tracts, and simply to keep track of them, we have numbered all of the 160-acre spacing units with a number.

In association with those spacing units there is a name associated with the operator of that spacing unit.

And then you'll find a date and a number in red. At that particular point in time, those numbers represented the magnitude of overproduction. For example, in the southeast quarter of 28, Yates operated that spacing unit, and as of July 1st of this year it's 240,000 barrels of oil overproduced.

The evidence will demonstrate to you that Tim Gum, the supervisor in Artesia for the Oil Conservation Division, in about March of this year, discovered that Yates had significantly overproduced and was overproducing their North Dagger Draw spacing units, and he went to Yates in March of 1996 to discuss with them the problem and what if anything they would do to make it up.

He did not at that time require them to engage in any effort to make up the overproduction. He required that they not accumulate any further overproduction.

In response, then, in April, the testimony is that Mr. Bob Fant and others with Yates would see Mr. Gum, and instead of developing a plan to make up this overproduction, Yates proposed to file an Oil Conservation Division application, which would simply cancel the overproduction.

In addition, they were seeking changes in the rules which would allow them, then, to go forward and produce these wells at capacity, or at least at the capacity, the substantial capacity of these submersible pumps.

If their request is approved, then for all practical purposes these pools are not prorated.

They're asking in North Dagger Draw that the oil allowable go from 700 barrels a day to 4000 barrels a day. The gas-oil ratio would stay the same, and the gas allowable for that pool then becomes 40 million.

They've linked that request with a companion case in South Dagger Draw and simply have multiplied the numbers so that by linking the cases together, they're going to ask in South Dagger Draw that the oil allowable goes from 1400 barrels a day to 8000 barrels of oil a day and that the gas allowable now becomes 56 million a day.

Our evidence is going to be that there is no logical reason to do those kinds of things, that what we have here is a question about the producing rules for North Dagger Draw, and that's an issue that we think is separate and removed from the violations.

In order to have a basis to ask for the request, Yates is contending that at higher oil withdrawal rates, total fluid withdrawals, that the oil cut goes up. They're contending that you can produce more oil at high rates in the reservoir.

Our technical evidence is that there is significant risk of offset drainage that has occurred because of the Yates activity, and our geologist and engineer, Mr. Hardie and Mr. Beamer, are going to demonstrate to you the impact that this activity has had on Conoco's operated properties.

We are on the south edge of this rim in North Dagger Draw. We've got this Joyce Federal spacing unit with the Savannah well down here in the northeast of 32. We're offsetting some of the higher violations that are occurring.

The problem for us is that the technical evidence will demonstrate that this oil-productive dolomite, as we move into the area where Conoco has its interest, is relatively thin, and so the excessive pressure depletion that's occurred by the overproduction has put us in a position where we're never going to catch up. We have been permanently damaged by the activities of Yates in violating the rules.

We are not going to be ale to restore reservoir pressure after it's been withdrawn. There's no active replacement for the pressure. And as a consequence of exceeding the rules, Yates afforded themselves the opportunity to enjoy production in the reservoir at a time when reservoir pressure was higher. We're going to provide you pressure information to show you the magnitude of that impact upon us.

The Division Examiner heard this dispute back on May 2nd, and I will share with you not only my prehearing statement but a copy of his Order, so you can see how he crafted a solution.

First of all, he denied Yates's Application to forgive the overproduction. And he required them and any other operator in violation to commence activities to reduce their withdrawals so that they could not exceed more than 350 barrels of oil a day out of a spacing unit, but in addition required that they make up that overproduction within 18 months.

In addition, the Order dismissed the contention that Yates advanced that reservoir waste was occurring and you had to simply produce all these wells at capacity. He deferred that to an industry/operators' committee and asked that committee to be formed and to go about investigating the details of that issue and to report back within a time frame to the Oil Conservation Division.

The problem Conoco has with the Order is not the fact that the oil production is required to be made up. We certainly would like that made up. We think that if you shut these wells in now, that's appropriate. Our evidence is that you can shut these wells in and not cause damage.

Our dilemma is that even if you shut in all these spacing units that are in violation, we are still not protected. It is late in the life of the pressure in the reservoir, and we're permanently harmed, and we can't think of anything to do. And we can ask these experts when they testify. We can't think of anything to do to balance the ledger, and that's the problem.

The two witnesses I'm presenting to you are:

Mr. Bill Hardie. Mr. Hardie has had extensive experience in North Dagger Draw and South Dagger Draw. He's analyzed this reservoir thoroughly. He's going to provide you the geologic presentation.

In addition, he's worked with Robert Beamer, a reservoir engineer, and together they've analyzed the engineering information and the geologic information, and they'll provide you with their expert opinions and conclusions, at the end of which it will be our request that this Commission take action to immediately shut in the violating spacing units and at least afford us some opportunity to reduce the magnitude of damage that's occurred to us.

Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Were there additional opening statements in the case? Mr. Carroll.

MR. CARROLL: Mr. Chairman, the Division stands by the Order issued by the Division.

CHAIRMAN LEMAY: Thank you.

Mr. Carr, do you want to respond to the -- I assume -- within that -- I never heard the arguments why they shouldn't be consolidated. Do you still not want them to be consolidated?

MR. KELLAHIN: Let me show you how I've organized my presentation, and you can tell me how you'd like to proceed.

Mr. Beamer and Mr. Hardie have organized their presentation so they have distinct exhibits and testimonies in North Dagger Draw. We have a separate set of presentations for South Dagger Draw.

Our position is that while this is a continuous dolomite reservoir, we're dealing with substantially different fluids. North Dagger Draw can be handled separate and alone as an oil pool. We get down into the transition area where we're really dealing with a gas pool. We can handle them separately.

You may remember that modifications have been made in South Dagger Draw, separate and independent from either Indian Basin or North Dagger Draw, the last change of which was to take South Dagger Draw, which is an associated oil and gas pool, and prior to I think 1993 precluded simultaneous dedication of oil and gas wells in the same spacing unit. Mr. Hardie and Conoco was instrumental in asking the Division to change that rule. And so now you can have simultaneous dedication.

So historically we've had cases were we've treated them differently. And our examination of the evidence is pointed directly at North Dagger Draw. That's the violation area, that's where all this overproduction occurred. And the only reason to talk about South Dagger Draw is, they're somehow linked by Yates with this multiplier and allowables.

We think they could be heard separately. If you would rather hear them together, you'll have to give me some flexibility because my presentations have been organized where we're going to divide our presentation into two parts.

CHAIRMAN LEMAY: Mr. Carr?

MR. CARR: Mr. Chairman, Mr. Kellahin stated that Conoco could handle them separately and has prepared its presentation in that fashion.

I would agree with Mr. Kellahin that the bulk of the evidence presented will address North Dagger Draw.

I would disagree with him that the reason we're looking at all of this at one time is because Yates has somehow linked them together. There were separate discoveries and the pools grew together.

And it wasn't because -- The boundary between the pools isn't because there was an engineering study and it said the North performs one way, the South another. It's because as they marched toward each other, that's where they met.

And so it's always been, as these rule changes have come before you, the policy of the Division, or at least the approach of the operators to consider them together.

In 1991, when the rules we're living under today were adopted, Yates and Conoco came before you together, and they said the rules are -- the pool merges, it's one big reservoir and that we ought to try to keep, to the extent possible, compatible rules.

The case was consolidated, both pools, before the Examiner. And to wait until commencement of the hearing to suggest that now we're going to march a new direction in presenting these matters is nothing more, I suggest, than an attempt to surprise us. I mean, we could sit here and present our exact case twice.

We've prepared the case as a *de novo* appeal of the one Order that addressed two pools, and we have a presentation that is one presentation that addresses two pools.

We think you can sort out whether or not there is some reason to have different rules or modify the rules in one pool as opposed to the other. But we have one presentation, and we think we should go forward that way, and we oppose separating them. We think they should be consolidated. Otherwise, we present the same case twice. And I understand you have tomorrow, but we may not need that if we can go and just get this thing over as we had anticipated doing.

We can certainly accommodate Conoco breaking their evidence down into two separate reservoirs, if that's how they've elected to look at it.

CHAIRMAN LEMAY: Give us just a minute.

(Off the record)

CHAIRMAN LEMAY: Okay, we'll hear the cases as consolidated. And you can make your presentation separately if you wish; we can link them together, Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Examiner.

CHAIRMAN LEMAY: Okay, shall we begin?

MR. CARR: At this time, Mr. Chairman, we would call Mr. Randy Patterson.

Mr. Chairman, we have had more people show up than we had sets of exhibits for, and if anyone needs an additional set of our exhibits, we can -- if you'll give me your name, I can provide those to you within a week.

CHAIRMAN LEMAY: Was there a motion to consolidate the record of the Examiner hearing?

MR. CARR: So moved.

CHAIRMAN LEMAY: Any objection?

MR. KELLAHIN: I'm sorry, Mr. Chairman?

CHAIRMAN LEMAY: A move to consolidate the record of the Examiner hearing in this case?

MR. KELLAHIN: I have no objection.

CHAIRMAN LEMAY: No objection, the record will be consolidated for purposes of this case.

Mr. Carr?

RANDY G. PATTERSON,

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. My name is Randy G. Patterson.
Q. Mr. Patterson, where do you reside?
A. Artesia, New Mexico.
Q. By whom are you employed?
A. I'm employed by Yates Petroleum Corporation.
Q. What is your current position with Yates Petroleum Corporation?
A. I'm the land manager, as well as the secretary of the corporation.
Q. And basically what do your duties entail at Yates?
A. I manage the land department and --
Q. -- act as secretary?
A. -- act as secretary of the corporation.
Q. Mr. Patterson, have you been called on before to testify before this Commission?
A. Yes, I have.
Q. In the past, have you -- has your testimony primarily focused on land matters?

A. Yes, for the most part, dealing with land.

Q. Are you familiar with the efforts of Yates Petroleum Corporation to develop its properties in North Dagger Draw and South Dagger Draw?

A. Yes, sir.

Q. Are you familiar with the status of the lands in these pools and wells operated thereon by Yates?

A. Yes, sir.

Q. Are you familiar with the Applications that have been filed by Yates in each of these cases?

A. Yes, sir, I am.

Q. And today are you authorized here to speak for Yates Petroleum Corporation at this hearing?

A. Yes, sir, I am.

Q. Have you prepared an exhibit for presentation here today?

A. Yes, sir.

MR. CARR: We would tender Mr. Patterson as an expert in petroleum land matters.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Carr) Mr. Patterson, could you first identify what has been marked Yates Petroleum Corporation Exhibit Number 1?

A. Yes, sir, and if I might step over here to the map and point out some features to you --

MR. CARR: And Mr. Chairman, I would note that the map on the easel differs from the map that has been distributed to the extent that we have attempted to place the pool boundaries on the map that's on the easel.

I also would qualify that by telling you that I did that and I've already been advised that I was in error, but the error is relatively small. The pool boundaries basically change, but what Mr. Patterson will be talking about will be the other matters shown on this exhibit.

THE WITNESS: Yates Exhibit Number 1 is the land map which shows the area of the Dagger Draw pools. It shows the development in the pools, North Dagger Draw in this area, South Dagger Draw in this area, and then continuing on down into the Indian Basin field, as Mr. Kellahin has pointed out.

Each individual spacing unit is shown, both the North Dagger Draw, as being 160-acre spacing, and South Dagger Draw, being 320-acre spacing.

There's a color code on your map that will indicate the operatorship of the wells. Yates wells are shown as black dots, Conoco wells are shown as blue dots, Nearburg-operated wells are shown as red or magenta sort of dots, and then other operators are shown in yellow.

Also, the ownership percentage of each spacing unit is shown in respective corners of the proration units, and you can see the legend at the bottom of the map showing that the upper right-hand corner, the numbers and the colored triangles in the upper right-hand corner, are Yates interests.

The color code, red, a red triangle would indicate a high-percentage well, 76 to 100 percent. A yellow would be a 51- to 75-percent interest in the spacing unit. A green color code in the triangle would be 26- to 50-percent interest in the spacing unit. And then a blue would be a smaller interest in the spacing unit.

So the upper right-hand corner would show Yates' interest, the upper left-hand corner will show Conoco's interests, and then in the lower left-hand corner Nearburg's interest will be shown in these respective spacing units, so that you kind of get an idea of the ownership of each one.

The Sawbuck Waterflood Project is shown here with lines connecting the area, showing the Sawbuck Waterflood Pilot Project.

Q. (By Mr. Carr) And that's in the South Dagger Draw?

A. That is correct, that's in the South Dagger Draw area.

Of course, each individual well location is spotted with the respective name of the well next to each well location.

Also, according to our geologist and engineers, the limits of the reservoir have been shown in a dark black line. I tried to outline where this thing exists, in our opinion.

And then, of course, as was already mentioned, the Indian Basin field moves on down toward the south part of the map.

Q. Mr. Patterson, on Mr. Kellahin's easel he's shown the overproduced area. Could you just generally point out where that overproduced area is on this map?

A. Yes, the overproduced area is the west part of Section 27, Section 28, Section 29, and part of Section 21, up here in North Dagger Draw.

Q. Are you familiar with the development of the rules which govern these pools?

A. Yes, sir.

Q. And when were the first special rules for the pool adopted by this Division?

A. I believe that was in 1973.

Q. And what happened at that time?

A. Mr. Roger Hanks was then an operator in that -- in the Dagger Draw area, and he made the request in 1973 for the first rules. Mr. Hanks had six wells at that time, and then he asked for a pool to be created for these wells and asked for 320-acre spacing and a 427-barrel-of-oil-per-day allowable.

Q. What justification did he present for those rules?

A. Well, I have actually pulled some quotes out of the 1991 hearing, for Mr. Jerry Hoover of Conoco. Mr. Hoover said at that time, His only justification for the spacing at that time was that these wells were producing with a high water cut, and from an operational expense point of view he did not feel like he could afford to develop on smaller spacing.

Q. And Mr. Hoover there was -- when he says "he", that means Mr. Hanks, does it not?

A. Yes, Mr. Hanks said that.

Q. And what did the OCD do with that request?

A. OCD granted the request by adopting temporary rules in 1973, and that was Order Number R-4691.

Q. What happened at the hearing on the permanent rules?

A. In 1976, Mr. Hanks again came to the Division when permanent rules were being considered and requested a downspacing to 160-acre units, because in three years of operation this pressure test extrapolated back to within 100 pounds of the original pressure. That's again a quote from Mr. Jerry Hoover at the 1991 hearing.

His assumption from that was that he was not efficiently draining the large areas that he had thought he might.

Q. And so what did the Division do at that time?

A. The Division entered Order Number R-4691-A, reducing the spacing to 160 acres.

Q. Did Mr. Hanks again come to the Division in 1976 concerning the rules for these pools?

A. Yes, he did, and again I'll quote Mr. Jerry Hoover of Conoco.

In September of 1976, Hanks came back again and requested an increase in the allowable up to 350 barrels per day. His statement was that he had several wells which were producing higher than 267, that had been given in 4691-A, and several new wells that he had drilled were initially coming in above that allowable, so he asked for the increase to 350 barrels of oil per day. This was granted in Order 4691-B.

Q. In summary, what was Mr. Hanks attempting to do with the special pool rules?

A. Well, Mr. Hanks asked and the Division granted rules which set allowables at levels that would not restrict the best well in the pools.

Q. Now, Mr. Patterson, there have been some other hearings on gas-oil ratios, but I want you to focus on spacing and oil allowables. Are you familiar with the 1991 hearing that addressed rules for these pools?

A. Yes, sir.

Q. And what happened at that time?

A. Well, on February 7, 1991, there were a request by Conoco in Case 10,221 to increase the oil allowable in the North Dagger Draw-Upper Pennsylvanian Pool from 350 barrels of oil per day to 700 barrels of oil per day.

Q. And why was that additional allowable needed?

A. Again, I've pulled some quotes from the transcript of that particular hearing, the February 7, 1991, hearing, and I'll give you several quotes.

Mr. Clyde Finley, who was then an engineer for Conoco, said, We needed to downspace, they had multiple wells on 160-acre units and needed additional allowable to accommodate additional wells on these spacing and proration units.

That was a quote.

Q. Was drainage discussed by Mr. Finley at that time?

A. Yes, Mr. Finley said that, Wells in the Dagger Draw are draining much smaller areas than 160-acre spacing. Wells were draining as little as 52 acres. So to be conservative, Conoco used 60 acres in its volumetric calculations.

Q. Mr. Patterson, was there testimony at that time concerning the potential for interference between wells in these pools?

A. Yes, sir, Mr. Finley continued and testified that, We are finding that additional wells are acting almost independently of the original wells with production, pressure histories, et cetera, that equal or are better than the original wells, and therefore the allowables for the original wells should be applied to the additional wells to allow additional density in the existing proration units.

He also testified that additional wells on 160-acre proration units are producing as good or better than the original wells.

Q. What was Mr. Finley's testimony about oil cuts in this pool?

A. Mr. Finley said that by drawing down wells at very rapid rates, the matrix is allowed to contribute in the dolomite. As we draw down, we tend to get better water cuts.

Q. Did he see evidence of the development of a secondary gas cap?

A. Again quoting from Mr. Finley, No evidence of the development of a secondary gas cap.

Q. How did Conoco testify about correlative rights in this case?

A. Again, Mr. Finley testified in February of 1991, Pressure data also showed that with higher rates and increased withdrawals, there was no negative impact on correlative rights. He said they saw no potential for correlative-rights impairment.

Q. Now, the Conoco Application addressed which reservoir, which pool?

A. That was the North Dagger Draw Pool.

Q. Did Yates join in that case?

A. Yes, we did join in that case.

Q. And did you not have also a companion case addressing the South Dagger Draw?

A. Yes, we did. We felt that since the North and South Dagger Draw were the same type rock and the same reservoir, that the per-acre allowables and such should be continued on down. So we did join with a compatible case in the South Dagger Draw.

Q. Can you summarize the argument that was presented to the Division? Just summarize what was presented at that time.

A. Well, Conoco sought to substantially increase the oil allowables, because it had proration units that could produce more than the allowable that existed, and their data showed that, first, wells produced more efficiently with less water at higher rates, and secondly that wells in the pool drained such small areas that they were not draining the acreage dedicated to them. And certainly they were not draining offsetting properties. They were, again, just as Mr. Hanks did, seeking allowables limits that would not restrict the best well in the pool.

Q. And what did the Division do with this joint Application?

A. The Division increased the allowables by Order Number R-4691-D.

Q. How do the arguments that are being presented today by Yates compare to the arguments that were presented in 1991?

A. The arguments that we will make with our technical witnesses today are essentially the same arguments that were presented in 1991.

Q. Mr. Patterson, what are the current rules in effect as of today for each of these pools?

A. Mr. Kellahin has already hit those points, but the current rules in each of the pools for North Dagger Draw now are 160-acre spacing, a depth-bracket allowable of 700 barrels of oil per day and a gas-oil ratio of 10,000 to 1.

In South Dagger Draw, that field is spaced on 320 acres. The depth bracket allowable is 1400 barrels of oil per day, and the gas-oil ratio is 7000 to 1.

Q. When did Yates first acquire its interest in these pools?

A. Yates has owned interest in this area back during the time that Roger Hanks was there. Before that time, they've owned leases and interest in that area for many, many years.

Q. Has Yates been actively developing this property since that time?

A. Yes. They did not actively pursue the drilling early on when Mr. Hanks was, because they felt that the technology was not there to produce the wells properly.

But in 1989 and 1990 they began to feel that they had the technology to produce the wells, and they began drilling, and they have been drilling actively and continually since, until today.

Q. Now, we're here today, Mr. Patterson, because there are certain proration units in these pools on which wells have substantially overproduced the assigned allowable. When did you become aware of that situation?

A. Last year, sometime in 1995, the management of Yates Petroleum did become aware that certain wells in this field, certain new wells, were not declining as rapidly as the usual well in the area, or what was typical, and that if those wells did not decline, they would and were becoming overproduced.

Q. And what did Yates do to respond to the situation?

A. Mr. Bob Fant of our engineering department met with the District Office in Artesia to discuss how to handle this situation.

Q. Was any agreement ever reached with the Division concerning how the situation was to be handled?

A. At that time there was no agreement reached. It was a discussion.

Q. And when did you next become aware of the magnitude of this situation?

A. This spring Mr. Gum contacted us, the Supervisor of the Artesia District, and wanted to meet with us because he had learned that this area was overproduced. And it's my understanding that Mr. Gum wanted us to give him our ideas on what to do about the situation.

Q. And did Yates meet with Mr. Gum?

A. Yes, sir, representatives, Mr. Brian Collins, who is the operations manager now at Yates Petroleum, Mr. Pinson McWhorter, engineering manager, and Mr. Bob Fant did meet with Mr. Gum.

Q. And what was the outcome of that meeting?

A. At that meeting, our representatives proposed to

Mr. Gum to curtail the production in the overproduced spacing units and bring those back to the allowable rate of 700 barrels of oil per day.

And we also proposed to immediately seek from the Division, from the Oil Conservation Division, an order to address the overproduction in the pool. It's my understanding that Mr. Gum agreed with this proposal.

Q. Did Yates curtail wells pursuant to that agreement?

A. Yes, we did.

Q. And did Yates immediately seek a hearing to deal with the overproduction in these pools?

A. Yes, sir, we immediately asked for that hearing.

Q. Could you briefly state what Yates Corporation sought and seeks in these cases?

A. At the May, 1996, hearing Yates Petroleum asked under Case 11,525, which applies to the North Dagger Draw-Upper Pennsylvanian Pool, that the special depth bracket allowable be increased to 4000 barrels of oil per day for each 160-acre spacing unit, proration unit, and we also requested the cancellation of all overproduction in the pool on the date the requested depth bracket allowable would become effective.

In Case 11,526, which applies to the South Dagger Draw-Upper Pennsylvanian Pool, we requested that the special depth bracket allowable be increased to 8000 barrels of oil per day for each 320-acre proration unit and likewise cancellation of all overproduction in the pool on the date the requested depth bracket allowable would become effective.

Q. Mr. Patterson, aren't these requested depth bracket allowables extremely high rates?

A. That was my reaction when our engineers told me first that they were going to request 4000 barrels in North Dagger Draw. I said that seems awful high. Why do you want to do that?

Then they explained to me the technical data, that we have some wells that are capable of producing 2500 barrels of oil a day and 1700, 1800 barrels of oil a day, and so therefore the request for 4000 barrels of oil a day in the North Dagger Draw is merely doing what Mr. Hanks did early on and what Conoco did in 1991, and that is to ask the Commission to increase the allowable so as not to restrict the highest producers in the field.

Q. When was this case originally set for hearing?

A. The case was set on May 2, 1996.

Q. And did Yates seek or concur in a continuance for that hearing date?

A. Yates Petroleum did not seek a continuance of that hearing. Conoco requested a continuance. They asked us about a continuance, and we advised them and the Division on April 29th that we did not object to the continuance but, because of our agreement with Mr. Gum, that we would immediately seek an order of the Division to solve this problem. We felt we could not join in a request for a continuance, so we did not.

Q. And was that request granted?

A. No, the Division did not grant the continuance, because they felt it was too urgent. The Division said, and I quote, There appears to be an urgent need to commence with these proceedings.

Q. And when was that case actually heard?

A. That case was heard on May 2nd, 1996.

Q. And when was an order entered by the Division in this matter?

A. The Order was entered by the Division on August 14, 1996.

Q. And Yates will present testimony and evidence on the impact of that delay on the reservoir with its technical witnesses; is that right?

A. Yes --

Q. And what --

A. -- we will.

Q. -- generally, in summary, will be the impact as we define it?

A. I understand that we estimated that over 2200 [*sic*] barrels of oil were lost. They became unable to be produced and were wasted in the 104 days it took to issue the Order.

Also, we incurred additional operating expenses in excess of $200,000 because of burning up pump motors and having to change out those bottomhole pumps.

Q. Mr. Patterson, the lost reserves were estimated to be what? 2200 or 22,000 barrels of oil?

A. I'm sorry, 22,000 barrels.

Q. How did the Division rule on the Application of Yates?

A. The Division denied the request for an increase in the pool allowables in paragraph 1 of the Order. It reduced -- The Order reduced the allowable rate on the overproduced units to 50 percent of the normal allowable limit, or reduced that ability to produce to 350 barrels of oil per day.

The Order further required that all overproduction be made up within 18 months of August 15th, 1996. The Order required the operators of overproduced units to report monthly to the Supervisor of the Artesia District Office as to the status of production from all wells in the affected units.

The Order established a committee to be formed of operators in the pools, to review the rules for those pools, and it set the last Examiner hearing in January, 1998, as a date for the committee to make a recommendation for rule changes.

The Order also announced that it would not change the rules for these pools in 1998 unless there was a, quote, cooperative recommendation from the committee, unquote, for new rules.

Q. Is Yates currently restricting production from these spacing units?

A. Yes, Yates Petroleum is restricting production from these overproduced units. Even though the Order was stayed, we have pulled the production back on these overproduced spacing units and are producing at or below the 350-barrels-of-oil-per-day limit, which was put forth in the Division Order.

Q. Mr. Patterson, what does Yates Petroleum Corporation recommend to this Commission be done about the overproduction in these pools?

A. Yates Petroleum Corporation has overproduced the allowables in these proration units, in these pools, and we are out of compliance with the allowable rules. Yates will make up this overproduction in accordance with the Order that was issued August 14th, unless this Commission sees fit to direct otherwise.

Yates will not make further recommendations concerning the past production from these pools, and we actually agree with Mr. Kellahin's statement a while ago that the overproduction problem is separate and removed from the allowable question.

There are some very important issues concerning the current allowables for these pools, and it's our intention to focus this presentation today on what we know to be occurring in these pools, in the reservoir, and what urgently needs to be done, now, to prevent the waste of oil, and not dwell on the overproduction in the past.

Q. Now, Mr. Patterson, looking at the August 14 Order and the provisions in that Order concerning makeup of overproduction, if allowables are increased in the future, would it be Yates' position that the overproduction still should be made up under existing current allowable limits?

A. Yes, sir, that's the way that that would be made up, is 350 barrels per day, weighed against a 700-barrel-a-day allowable.

Q. And that would give, in fact, operators incentives to get on with getting these wells back into line, would it not?

A. That's correct.

Q. Is Yates prepared to work on the committee established by the August Division Order?

A. Yes, sir, we are prepared to work on that committee if there is a committee.

But we do not think that that is the way to solve this problem. We are opposed to this committee.

We believe that it's the OCD's duty to listen to the scientific presentations and to make regulatory decisions. We do not believe that the Oil Conservation Division or the Commission should dodge this duty to make those regulatory decisions by pushing it off on an operators' committee.

So I say if there is an operators' committee, because the things that are happening in these pools, if they're not immediately addressed by this Commission, it's going to result in substantial permanent waste of oil.

So rather than using this committee, we believe that this Commission should act immediately on these problems.

So we are going to focus our presentation here today on the recent developments in the pools and the need for immediate changes to the rules for these pools.

Q. Now, Mr. Patterson, will Yates call geological and engineering witnesses to review those technical portions of this case?

A. Yes, sir, we will.

Q. Was Exhibit Number 1 prepared by you or compiled under your direction?

A. Yes, sir, it was.

MR. CARR: At this time, may it please the Commission, we would move the admission into evidence of Yates Petroleum Corporation Exhibit Number 1.

CHAIRMAN LEMAY: Without objection, Exhibit Number 1 will be admitted into the record.

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

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Patterson, you and I and Mr. Carr have the benefit of having a copy of the Division Order. I'm going to share copies with the Commission.

Mr. Patterson, let me talk about your proposal to the Commission with regards to making up the overproduction.

Do your records reflect the magnitude of overproduction from North Dagger Draw for the spacing units for the Yates-operated wells?

A. Yes.

Q. At what point in chronology did you stop accumulating overproduction in excess of the 700-barrel-a-day allowable for those spacing units?

A. I believe that was at the time, as I testified before, that Mr. Fant and our people met with Mr. Gum.

Q. That's in approximately April of this year?

A. That's correct.

Q. You did not attend those meetings, did you, sir?

A. I did not.

Q. When we look at your proposal to abide by the Examiner Order, which would be making up the overproduction at the rate of 350 barrels per day per spacing unit, and that would be made up using an allowable of 700 a day, have you calculated or had your technical people calculate whether or not you can get into full compliance within the 18-month time frame set forth in the Examiner Order?

A. Our technical people have looked at that, and it's my understanding that they believe that we can.

Q. Okay.

A. That is, if the Commission does not see fit to change that manner of making it up. As we said before, we are still seeking that this overproduction be canceled.

Q. All right, that's what I'm trying to clarify. You are not by your testimony conceding that point in the Examiner Order; you still want the overproduction canceled?

A. We believe that's the proper thing to do. However, we are willing to do as I've said and make up that production and have already begun to do so.

Q. I just want to make sure I understood you that you still want it canceled, but if it is not canceled then you have no disagreement with the method by which it's to be made up in the Examiner Order?

A. That's correct. We believe our technical people will show all the reasons that this overproduction should be canceled.

Q. In part of your presentation, you reviewed a series of Roger Hanks' presentations to the Division that occurred, 1973, 1976, and again in 1976, and then there was a subsequent hearing in March -- or an order on March 21st of 1999 [*sic*] in which the oil rate went from 350 a day to 750 [*sic*] a day.

Let me start with the last hearing that you described. That was a request that resulted from a cooperative consensus of the operators in that pool, including Yates, to increase the oil rate to 700 a day; is that not true, Mr. Patterson?

A. I understand that you're talking about the February, 1991, hearing. I believe you said 1999.

Q. I'm sorry, I misspoke. It's the February, 1991, hearing and the order from which is Order 4691-D.

A. Yes, sir.

Q. All right. That hearing --

A. There was a cooperative effort.

Q. All right. The evidence at that hearing was that at rates not in excess of 700 barrels a day, then there was not interference among wells on the spacing units; is that not true, Mr. Patterson?

A. I believe that that's what Mr. Finley testified to at that time, and the rate of 700 barrels a day was actually the amount that would not restrict the best wells that were producing at that time.

Q. All right. There was no indication in the record, is that not true, that any interference was occurring? In other words, no party came forward to show interference was occurring with the wells at rates up to 700 barrels a day?

A. I did not attend that hearing, so I don't believe that I can answer that question, and I expect that our technical witness will probably handle that.

Q. All right. Was there any evidence presented in that record to show whether this -- the drainage areas that were being impacted at rates of 700 a day?

A. As I believe I quoted, Mr. Finley stated that the wells were draining as little as 52 acres and that there was no interference in his calculations.

Q. When we went back to the Hanks presentations in 1973 and 1976, there was virtually no technical evidence presented at any of those hearings; is that not true, Mr. Patterson?

A. Again, I was not at those hearings, and the information that I have was actually obtained from Mr. Hoover's quotes of Mr. Hanks at the 1991 hearing.

We tried to get the transcripts to those Hanks hearings, and the local office in Artesia couldn't put their hands on them. We looked in Santa Fe. We could not obtain the transcripts to those hearings.

Q. You said that management of Yates became aware in 1995 that you were overproducing your North Dagger Draw -- certain of your North Dagger Draw spacing units?

A. No, that's not what I said. I said that management became aware that these wells were not declining at the rates that were historical in the area, but the wells were -- all the wells start producing at very high rates and then have a rapid decline, and these wells were not experiencing those declines. These wells were very good wells, and they seemed to hold up.

Q. You said very good wells. What kind of rates were you getting on a daily basis?

A. As I testified a while ago, some of these wells were 2400, 2500 barrels of oil a day.

Q. Well, and that would be at rates in excess of the allowable; is that not true?

A. That is a rate that's in excess of the allowable, that's correct.

Q. So Yates management knew that you had wells that had the capacity to overproduce the allowable?

A. That's correct.

Q. And you knew that in 1995?

A. We were aware that those wells were very good.

Q. When did you first become aware in 1995 that you had wells in North Dagger Draw that individually could exceed the allowable for a 160-acre spacing unit?

A. I can't tell you a date. Maybe our technical witness can.

Q. What if any -- who is -- When you talk about Yates management, who is Yates management that is aware of this?

A. The Yateses, the owners of the company.

Q. John Yates?

A. That's -- He's one of them.

Q. All right. Are you involved in those decisions about the rates at which to produce these wells, Mr. Patterson?

A. Personally, I am aware of those. I attend meetings. I am sometimes involved.

Q. It's not your responsibility, though, to comply with the producing rules for North Dagger Draw; is that correct?

A. It's every company's responsibility to comply with the Rules of the Division.

Q. What individual in your company has that responsibility?

A. I think that we all have that responsibility as employees and managers of the company.

Q. All right. What then did you do to assure that these high-capacity wells were produced in compliance?

A. Well, as I testified before, we had our representatives talk with the District Supervisor to try to figure out these wells.

This area was produced in this manner, it wasn't uncommon that this happened. In fact, Conoco had produced their wells exactly the same way. When they first come on, they overproduce, they produce at a high rate. And Conoco, Mr. Nearburg, the other producers in the area, also produce their wells the same way.

Q. Can you show --

A. When we became aware of the fact that these were not declining, then we contacted the Division supervisor, and we were looking for a method to solve this problem. We didn't know exactly what to do about it, and the Commission -- or the Division didn't exactly know how to handle the situation.

Q. The next action taken occurs in March of 1996 when Mr. Gum comes to Yates and says, You're overproducing your spacing units in North Dagger Draw?

A. To my knowledge, in spring of 1996 Mr. Gum contacted us and informed us that some of these spacing units were overproduced, some of them quite a lot, and he asked us to look at it and to devise a plan of how to solve the problem, which is what we did, and we came back to him as I testified, we immediately took action.

Q. When the oil rate in the pool for the spacing units went from 350 a day to 700 a day, back in 1991, was there any overproduction canceled?

A. To my knowledge, there was not. To my knowledge, there was no overproduction at that time to be canceled.

Q. In March 21st of 1991, then, that change allowed the operators prospectively to produce at the higher oil rate of 700 a day?

A. That allowed them to produce at the higher oil rate, which was in fact higher than -- or at the level of the highest producing well in the field at that time.

Q. Okay.

A. That's what we're asking at this time.

Q. All right. To the best of your knowledge, did any personnel with Yates disclose to Mr. Gum in 1991 -- I mean in 1995 -- that you were overproducing any of your spacing units?

A. I did not attend that meeting and exactly what was said, I do not know, but I believe Mr. Fant did.

Q. Okay. In March of 1996 did you attend the first meeting with Mr. Gum?

A. No, I did not.

Q. Did you attend the second meeting, in April of 1996, with Mr. Gum?

A. No, I did not.

Q. Why were the wells overproduced, Mr. Patterson, without seeking Division approval or a change in the rules prior to April of 1996?

A. As I stated we were trying to see if these wells were going to decline, to come back into compliance as the operators tend to do with those higher producing wells. As I stated before, Conoco has produced their wells in the same manner. These wells did not fall off, and therefore they became overproduced.

Q. Are you aware of any Conoco spacing unit that's overproduced?

A. At this time, they are not.

Q. That ever was overproduced?

A. Yes, there are some that have been overproduced and produced in the same manner that ours were produced.

A. That they were overproduced for in excess of a year?

A. I couldn't testify to that. I don't know what the timing was.

Q. Why didn't you seek Mr. Gum's approval to overproduce the spacing units?

A. As I said, we were trying to find a way to solve this problem. It was very complicated and we didn't know exactly how to go about it, and the Division didn't know exactly how to go about it either.

Q. Did you suggest or did Yates personnel suggest to Mr. Gum in the summer of 1995 that you might actually conduct some type of step-rate tests on these high-capacity wells to see what happened?

A. I do not recall. I don't know.

Q. Do you know if Yates ever contacted any of the other operators in the pool to work out a common scheme or an effort to analyze and try to resolve this issue?

A. I don't know that.

Q. Didn't occur, did it?

A. I don't know that.

Q. Whose responsibility would that have been?

A. Probably our production and engineering staff.

Q. Is there an operation manager that's responsible for compliance with the pool allowables for Dagger Draw?

A. The operation manager, Mr. Brian Collins, is responsible for production and for engineering on those wells.

Q. And would he be aware, to your knowledge, of the limits in the producing allowable for that pool?

A. I am sure that he is aware of those limits. I am sure that he's aware of the rules, yes.

Q. When did he assume his responsibilities as operation manager?

A. It was early 1996, and I can't tell you the exact date.

Q. So there was a period of overproduction that would not have been on his watch?

A. That's correct.

Q. Who would that person have been that he replaced as operation manager?

A. Mr. Mike Slater was operation manager prior to Mr. Collins, and he retired from Yates Petroleum.

Q. Would Mr. Slater or Mr. Collins have the authority as an operation manager to take one of these high-capacity wells that they know can overproduce the spacing unit allowable and do so without management approval?

A. Would you state that again? I missed --

Q. Yes, sir, let me state it a different way --

A. -- the point of the question.

Q. -- and see if I can make it clear.

If Mr. Slater is the operation manager, he now has a well that will produce in excess of the allowable, would he decide to do that, produce it in excess of the allowable, or does he report to someone above him and obtain specific authority to overproduce the spacing unit?

A. I think that the operations manager produced those wells at the optimum rate, in order to produce the oil from the ground, optimize the well, and to prevent the waste of any of the oil from occurring. If these wells are not operated properly, you do waste oil, as I stated before.

And I believe that that is exactly what they did, was operate these wells so as to not create any waste, and these wells did not fall off as wells have previously done, our wells, Conoco's, Mewbourne's, Nearburg's. These wells did not perform as wells had in the past. These wells are better wells than those.

Q. So if Mr. Slater reaches his own conclusion about waste, then he'll overproduce the spacing unit?

A. I think that there's a -- You characterize his conclusion. We have engineering staff, and you will see in the presentation here as to our conclusions of the waste and what causes it to occur, and we have had that conclusion for a considerable amount of time and believe it's the correct conclusion.

Q. You had that conclusion for eight, nine months, before you brought that conclusion to the Division and asked for any type of relief?

A. I can't tell you the timing on that, no.

Q. Let me ask you about the operations in the overproduced violation area, Mr. Patterson. Let me show you what I've marked as Conoco Exhibit A.

As the land manager, Mr. Patterson, were you involved in March -- February and March of 1995, with proposing additional drilling in North Dagger Draw in what now I would characterize to be the violation area?

A. I was aware of the wells proposed during that period of time in this area where the overproduction occurred.

Q. I've showed you what I've marked as Conoco Exhibit A. It's a tabulation of Yates' letters. All but the first purport to have your signature. Would you take a moment and see if these are correct copies of letters that you executed?

In addition, can you authenticate Mecca's signature on the first letter of February 23rd?

A. These are proposal letters that we sent to Nearburg Exploration and other working interest owners, proposing wells during that period of time.

Ms. Mecca Mauritsen of our office did sign the first proposal letter, and I notice that the last proposal letter was signed for me by Janet Richardson. The "JR" initials there are Janet Richardson of our office, and she did sign that on my behalf. I was probably out of town.

And these proposals were made to Nearburg.

I'm curious as to how Conoco obtained copies of these proposal letters from Nearburg.

MR. KELLAHIN: Well, if you'll look on the front, it was Exhibit 5 in a public hearing before the Division, held in August. It's Case 11,311, Mr. Patterson.

We move the introduction of Exhibit Conoco A, Mr. Chairman.

MR. CARR: I have no objection.

CHAIRMAN LEMAY: Without objection, it will be admitted into the record.

Q. (By Mr. Kellahin) Mr. Patterson, in a period of about 30 days, beginning in February and ending in March of 1995, Yates proposes some 39 North Dagger Draw wells to Nearburg. What was going on? What are you doing?

A. That particular group of proposals stemmed from an argument that we were having with Mr. Nearburg. It had nothing to do with allowable or with the producing rate of these wells. It was mostly an argument over operatorship. And as you know, under an operating agreement or -- There is a procedure for proposing wells, and if you don't comply with that procedure it's possible that the operatorship can be removed to another party, and this was mostly an argument over that. We also received several proposals from Mr. Nearburg.

Q. As a result of the competition between Yates and Nearburg, as represented by these 39 proposals, there were a number of infill wells drilled in North Dagger Draw in existing 160-acre spacing units, were there not?

A. Those -- There were some wells drilled. I would not characterize it as being as a result of these proposals. Those wells were slated to be drilled in the usual and normal manner, and there were none of those drilled at a time period when that spacing unit was over the allowable producing rate.

Q. Are you absolutely certain of that, Mr. Patterson?

A. Except for one.

Q. All right.

A. And there was one exception, and that was the well that was before the District Court in Eddy County, and the Court was very interested in that well being drilled, and so it was drilled when the spacing unit was above the 700-barrel rate. None of these other wells were drilled when the spacing unit was above the allowable rate.

And again, these wells were drilled as they would have been drilled normally, and really these proposals were no more than just get the paperwork done and the argument about the operatorship.

Q. Are you referring to the southeast quarter of Section 29, which has the Boyd 5 wells in it?

A. The Boyd X 5 was the well that was drilled, because the judge was very interested in seeing that well drilled.

Q. Did the judge's desire to have the well drilled have anything to do with continuing to produce that spacing unit at over its allowable?

A. That, as I stated before, when those wells are completed, if those wells are not produced at an optimum rate the reservoir will be damaged, and I believe Mr. Fant is going to show that extensively.

Q. Did you take that position to the regulators to have it authenticated by them to see if they agreed with that position?

A. I don't know exactly what the conversations were. I was not at those meetings, as I've already testified.

MR. KELLAHIN: Thank you, Mr. Chairman, I have no further questions.

CHAIRMAN LEMAY: Thank you.

Additional questions? Yes, sir?

EXAMINATION

BY MR. BRUCE:

Q. Just one question, Mr. Patterson. I'm kind of confused about Yates' proposal.

Assuming overproduction wasn't canceled, how would you propose that overproduction is reduced? Would it be against the 700-barrel-per-day current allowable, or if the Commission approved an increase in the allowable would that be measured against the increased allowable?

A. Mr. Bruce, as I stated earlier, Yates Petroleum has accepted the Division's outline in the Order to make up the overproduction at 350 barrels or less per day, as compared to a 700-barrel-a-day allowable, which is the -- and was the existing allowable in the field.

However, we are asking -- We will do that if this Commission decides that that should be done, or if they do not change and decide to do something else. We are asking immediate attention to the allowable to increase for the balance of the wells in the field, and that's what we are seeking today and would like to focus on.

But the makeup will be done against the 700 barrels which existed at the time the overproduction occurred.

CHAIRMAN LEMAY: Additional questions?

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Are the saltwater disposal wells for the produced water from these production wells, are they also located within the field, or is the saltwater transported to some other distant area?

A. No, ma'am, we have a system of -- and I may misspeak here -- I believe a dozen saltwater disposal wells, at least ten saltwater disposal wells that are located in this area.

Q. Are they reinjecting into the Canyon or into some other formation, do you know?

A. Those disposal wells are in various formations, Devonian -- And I can't tell you exactly the answer to that question. I don't know if there are any presently injecting into the Canyon or not. Maybe Mr. Fant could answer that question for you.

COMMISSIONER BAILEY: That's all.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yes, sir, Mr. Patterson --

A. Yes, sir.

Q. -- you say you frequently have arguments over operatorship. This one was apparently resolved?

A. Well, the Boyd X 5 actually went to court, and there was an order issued by the District Court in Carlsbad. That order has been appealed to the Court of Appeals, and that is presently pending before the Court of Appeals.

The rest of these wells were all resolved. Some of these wells -- and I'd have to check exactly which ones, maybe all of these wells have now been drilled. I rather doubt that they have all been drilled.

Q. Well, I guess what I was wondering was about unitization. This is a field that's crying for unitization, rather than some regulatory approach to it. Has that been investigated?

A. There have been talks of unitization. No material negotiations or steps have been taken, and no requests have been filed with this Division yet for unitization.

COMMISSIONER WEISS: Thank you, that was my only question.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Patterson. I just want to get some dates straight here.

Was it your testimony that Yates management became aware that Yates wells were overproduced in 1995?

Is there a month in 1995 that management became aware of that?

A. I can't tell you a month, and I said that they became aware that these wells were not declining, and therefore I guess the inference can be made that they were becoming overproduced.

But these wells were holding up very well, and it was a little baffling to the Yateses that these wells were not declining and not performing as other wells had in the field.

Now, when Yateses actually became aware that they were getting out of compliance, I can't tell you an exact date on that.

Q. Okay. So that -- I'm trying to find out the difference between not declining and being overproduced. If they don't decline, they start at a higher rate, and the obvious conclusion is, they're going to be overproduced --

A. They become overproduced, yes, sir, that's correct.

Now, when the Yateses actually became aware that they were getting out of compliance, I can't tell you that exact date.

Q. Okay. I'm getting at semantics. You're talking about becoming -- not declining, and then we're talking about overproduced. If a well doesn't decline, the obvious assumption is, it's going to be overproduced. Whose decision was it in Yates to continue overproduction?

A. Well, I don't know that there was a conscious decision to do that, Mr. LeMay. As I said, this field, as well as other fields in the State of New Mexico, come on at high production rates, and then in a matter of months they fall off and become lower than the allowables.

There is a period of time that these wells, as well as Conoco wells, as I said, and Nearburg wells, go into an overproduced status, and then as they decline rapidly they go back into -- it all averages out, and it goes into compliance.

And as I say, these wells produce that way, that's the optimum method to produce these wells, as well as -- It happens in other fields, not only in Dagger Draw.

Q. Well, I'm still confused. If the wells don't decline, there's a period of time in 1995 when -- I understand your testimony was that these wells weren't declining, but who first contacted who concerning the overproduction? Did Yates contact our office, or did our office contact you concerning the overproduction status?

A. It's my understanding that we made the first contact in 1995 with the office.

Now, in 1996, Mr. Gum did come to us and said, Hey, you're overproduced, we need to do something about this.

Q. Can you explain the 1995 contact, by whom to who, concerning what?

A. I believe Mr. Fant made that contact --

Q. Okay.

A. -- yes.

CHAIRMAN LEMAY: We'll ask him.

Okay. Thank you, That's all the questions I have.

Anything additional?

Okay, Mr. Patterson, you may be excused.

THE WITNESS: Thank you.

CHAIRMAN LEMAY: Let's take about a 15-minute break.

(Thereupon, a recess was taken at 10:07 a.m.)

(The following proceedings had at 10:24.m.)

CHAIRMAN LEMAY: Okay, we shall resume.

Mr. Carr?

MR. CARR: Thank you, Mr. LeMay.

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. Artesia, New Mexico.

Q. By whom are you employed?

A. Yates Petroleum.

Q. What is your position with Yates Petroleum Corporation?

A. I'm a geologist.

Q. Have you previously testified before the New Mexico Oil Conservation Commission?

A. Yes, I have.

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

A. Yes, they were.

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

A. Yes, I am.

Q. Have you made a geological study of the Canyon or Upper Pennsylvanian formation in this area?

A. Yes, I have.

Q. And are you prepared to share the results of that study with the Commission?

A. Yes, I am.

MR. CARR: Are Mr. May's credentials acceptable?

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Carr) Mr. May, let's go to your structure map, which has been marked Yates Exhibit Number 2, and I would ask you to identify and review that, please.

A. This is a structure map on top of the Canyon dolomite. The contour intervals are 50 foot. The colors denote 100-foot intervals, though.

The dark lines outlining the colored area show the edge of the dolomite body, and the North Dagger Draw Pool is in basically Township 19 South, 25 East, the southeastern portion of 19 South, 24 East, and a little bit of the northern portion of 20 South, 24 East.

South Dagger Draw Pool is the balance of 20 South, 24 East, also part of Township 20 1/2 South, 23 East and the northern part of 21 South, 23 East.

And then Indian Basin Pool, which goes off the bottom part of the map, takes up the balance of 21-23 and another township or two to the south.

The red dots denote oil wells, and then we have the standard gas wells. Most of the oil-well symbols within the colored area are what I call Canyon or Upper Penn producers from the dolomite.

Down in South Dagger there are some gas-well symbols. Many of those do produce gas from the Upper Penn or Canyon dolomite.

In North Dagger, most of the gas-well symbols are older Morrow producers, almost -- In fact, I believe almost all of the producers in North Dagger are oil.

You might note that Indian Basin, which is basically off the bottom part of the map, is one of the must structurally high areas. South Dagger is a little bit lower than Indian Basin, and North Dagger structurally is lowest of the pools.

Note that I represent the Canyon or Upper Penn dolomite continuous from North Dagger to South Dagger, in the Indian Basin and even on down into the Indian Basin Associated Pool, further, even further to the southeast.

I might just -- I'd like to go into just a little bit, briefly, of production history.

Back in the 1970s, Mr. Hanks and a few other operators started drilling some wells in this formation, and I believe most of those were in North Dagger, along the western side of Township 19 South, 25 East. He had some success, but it was limited. I believe he was kind of restricted on making good wells, because at that time sub pumps were not in use.

Later, in the 1980s, the sub pumps came around, and in the late 1980s there was some very brisk drilling activity occurred in South Dagger, and basically a quite aggressive development of South Dagger Draw, mostly in Township 20 South, 24 East. There was also some up in North Dagger Draw, over in 19-24, and in the western part of 19 South, 25 East.

This development has progressed steadily since the late 1980s to the present time, and it currently has been moving to the northeast in North Dagger Draw and has moved over into the area of the overproduction problems.

You can see where a lot of the wells, the production, current production, is stopped to the northeast, in North Dagger Draw, and I believe, that -- I shouldn't use the word "stopped", it's currently -- where it's currently at. It probably will continue to the northeast. Where, I do not know.

Also, there's been a recent spurt of activity down in the very southern part of South Dagger, mostly in Township 20 1/2 South, 23 East, and 21 South, 23 East. There's been quite an aggressive program down there by Marathon. In fact, here just recently, part of the old Indian Basin Pool, part of that acreage was taken out of the old Indian Basin Pool and put into South Dagger Draw.

This is a very -- Even though the rock is continuous from North Dagger down into Indian Basin, this is a very complex reservoir. It's one of the most complex that I have ever encountered or seen, and I don't feel I'm alone in that characterization.

We believe, looking at the structure map, in South Dagger -- I guess I should start off -- All of those wells produce water with the oil and/or gas they make. It doesn't matter where you're at in a section. You can be -- in North and South Dagger Draws. You can be at the most structurally high spot in one of those two pools, and you still produce water.

There is a point, though, when you go down in the section, downstructure, that you lose your hydrocarbon production and have nothing but water production. And this -- and I'm going to use the term loosely, oil-water contact, is not consistent throughout the two pools. It varies. In a localized area, you can get a feel for it, in a very localized area. But in general, it changes.

In South Dagger, if you perforated a well in South Dagger at a structurally equivalent area in North Dagger and produced that well, you would get nothing but water. So in other words, the productive intervals are structurally higher in South Dagger than in North Dagger, and that's a general statement.

So it appears that the further northeast you go, the lower in the section you can have production, and that's what we're seeing in North Dagger Draw. So the oil-water contacts -- and like I say, I use that loosely because sometimes you can't put your finger on it. It's a gradational area sometimes in some wells. It will move around. In some localized areas you can get a feel for it, but once you move out of that localized area, it can change. And we have been surprised numerous times on how far down we can perforate.

Q. Mr. May, you're going to have to speak a little louder, one.

A. Okay.

Q. And when you talk about the complex reservoir and the oil-water contact in South Dagger Draw and North Dagger Draw, was it your testimony that you have different oil-water contacts in those two pools, or that it varies even within those pools?

A. It can vary, and even -- You can even get varying oil-water cuts in different zones within the Canyon dolomite.

Also -- and I'll talk a little bit about it more when I go into the next exhibit, but we feel like that this reservoir is compartmentalized. It is not one homogeneous reservoir, not by a long shot.

Q. Can you just basically in summary tell us what is the significance of structure as you go about developing in Dagger Draw?

A. Structure helps you, but it's not a panacea by any means. What it does is, if you get higher in structure, that means you have the potential to have a thicker hydrocarbon section above that, quote, oil-water contact. But you can still drill on a high spot, on noses, on closures, and get poor wells.

So it does not necessarily mean because you're structurally high you're going to get good wells. You can drill off on the flanks, in lower parts of the field, and have very good wells. So it helps, but you have to be very careful that just because you're running high structurally doesn't mean you're going to have a good well.

Q. All right. Let's go to the isopach map, Yates Exhibit Number 3. Would you identify and review that? First, how was this prepared? Was it well control, or was seismic integrated into your study?

A. This is exclusively well data, subsurface data.

Q. Would you review what this exhibit shows?

A. Again, the wells are shown, again, the zero -- in fact, the zero dolomite line is shown as the heavy line on the outsides of the colored area. The contour intervals are 50-foot intervals. The colors denote 100-foot intervals.

And this is basically a dolomite -- net dolomite thickness map. In other words, I counted up all the dolomite present in each well and spotted it.

Q. Looking at this exhibit, it appears that all wells in both pools, then, basically are producing out of the same geologic body; is that right?

A. Yes, it is continuous. There are no breaks that I have found from the different pools.

Q. Are they in the same basic geologic formation?

A. Yes, they're all in the Upper Penn, or what I call the Canyon, and the same dolomite body.

And I might go in here at this point and talk a little bit about this dolomite body. It was originally, in my opinion, a carbonate bank. It was formed in shallow water, it was originally deposited as limestone. Later it was buried, and after burial diagenesis converted much of the limestone into dolomite. There is still limestone, can be above and below the dolomite body, not always. And to the areas outside the colored area, there's limestone present in many areas.

So the limestone is actually tight and forms some of the seal for the dolomite, and the dolomite is the reservoir itself. This bank was growing at the time.

And it didn't grow as one continuous bank, nice and uniform. It's very -- it's a very complex -- I think many areas were growing -- could possibly have been growing at different rates than other areas. I think many areas may have been at one time isolated from each other as far as the actual bank itself and then eventually grew together.

And I think that helps explain some of the compartmentalization, because we feel like even though diagenesis occurred -- it converted the dolomite, it rearranged some of the porosity -- some of the original depositional environments influenced some of the better porosity at this time.

And so it was a very dynamic situation. And we feel like that because of the way it grew, it explains why -- in some part, why we feel like the reservoir is compartmentalized.

Q. Now, what do you mean by compartmentalized?

A. In other words, you've got, per se, maybe pockets of porosity and permeability within the dolomite, and many times they may not be interconnected. There may not be permeable paths in between them, completely.

That's another thing to point out, is, the porosity and permeability varies greatly within this dolomite. You can move from one well to -- In fact, we've seen this many times where you drill a good well, offset it 40 acres away, and you can drill a poor well. So it's a very -- very heterogeneous, is what I'm trying to get at.

Q. Do you see fracturing in the reservoir?

A. There can be fracturing. I don't think in North Dagger Draw that there is a lot of fracturing, but there can be fracturing within the -- in the dolomite.

Q. Now, when we look at these two exhibits, when we look at structure and compare it by where the thickest dolomite is located, do structural highs coincide with the thickness of the dolomite?

A. Well, some of the higher spots are over on the very western side of South Dagger in 20 South, 24 East, so not necessarily.

Now, there are some noses, structural noses and structural closes, that do correlate to some of the thicker parts. But then, also there's some that don't.

So in general, I don't think you can just lay out and say that the thicker parts of the dolomite automatically overlay the structural highs.

Q. When we look at the area that's been developed by Yates and contrast that with the area in which Conoco is developing, which of those wells are actually in the thickest portion of the reservoir?

A. Well, let's look at the area where the overproduction occurred, that Yates owns, is in 19 South, 25 East, and it's, I believe, more in the southern part of Section 21 which is in the thicker part of the dolomite. That green denotes the thickest part. You've got over 300 feet of dolomite.

There's also Section 28, where we overproduced. It's not in the thickest spot, but it's off to the flank.

And also in Section 29 we have production. Part of it is in the thicker part of the dolomite and part of it is off the flank.

The Conoco production that they had talked about is in Section 32 to the south. It's on the edge of the dolomite.

Q. Are you ready to go to your cross-section?

A. Yes.

Q. Let's go to the first cross-section in North Dagger Draw, Exhibit 4, cross-section A-A'.

A. This is structural cross-section, A-A'. It's in North Dagger Draw, and it's over the Canyon or Upper Canyon dolomite section.

I've got the top of the Canyon limestone marked. There's a thin limestone on top in some of these wells. Sometimes in other areas of the pool you'll have no limestone on top; it goes immediately from the shales above it into Canyon dolomite. I've got the dolomite marked, and it is colored in the bluish-purple color. I've also got the base of the dolomite.

Now, this is on a minus-4300 datum on structure. I've also got some correlation lines through here. You might note that the dolomite does cross the correlation lines, and the dolomite, in other words, is very erratic sometimes on what's been dolomitized and what has been left as limestone.

Starting off on the left-hand side of the cross-section, in Section 32 of 19 South, 25 East is the Conoco Joyce Federal Number 2. It's perforated and produces in the dolomite.

It's on the edge. You can see that the dolomite is starting to pinch out. There's a piece of dolomite in the top and a piece in the bottom, and there's limes and shales in between. This well IP'd for about 370 barrels of oil a day out of the Canyon.

The next well is the Yates Aspden "AOH" Federal Number 2. It's in Section 29 of 19 South, 25 East. I might point out that this well was originally -- Because of topography problems we had to move the surface location and deviate the well back to a standard location, bottomhole.

So if you look down at the perforations at the bottom that are listed, those perforations are based on measured vertical depth. The log itself is a true vertical depth log. So the perforations may not -- at the bottom may not act -- may not be similar in depth to the perforations on the log that are shown, because one is true vertical depth and the other is measured, and that's the difference.

But I did line up the measured-depth log with the perforations marked and marked the perforations on true vertical depth. So I feel they're in the correct spot.

This well IP'd for about 310 barrels of oil out of the Canyon.

The next well is the Yates Boyd "X" Number 4 in Section 29, 19 South, 25 East. Again, another Canyon producer. It produced [*sic*] for about 891 barrels of oil. We also ran a couple of DSTs on the way down, and they recovered a little bit of oil on the first one, and water, and the -- and the second one produced water.

The next well on the cross-section is the Aspden "AOH" Federal Number 3 in 29, 19 South, 25 East. Again, it's producing, and you might note that most of these wells are producing near the upper part of the dolomite, and that's where we have found the productive intervals in this area, this localized area, to be. This well IP'd for about 462 barrels of oil.

The next well is the Yates Binger "AKU" Number 1 in Section 29 of 19 South, 25 East. It IP'd for about 684 barrels of oil a day. We ran about five DSTs on the way down, with varying degrees of oil, water and mud recovery.

And then the last well on the far right is the Yates Patriot "AIZ" Number 2 in Section 20 of 19-25, 19

South, 25 East. And it IP'd for about 285 barrels of oil.

There's a location map -- I pointed this out earlier -- on the bottom right-hand corner showing the trace of the cross-section.

Q. Now, Mr. May, could you -- I'd like to direct your attention to the Aspden "AOH" Number 3 well. When was that initially -- When was that drilled?

A. If you look down, it was IP'd in June of 1995.

Q. Was it a good well?

A. Yes, it IP'd for about 462 barrels of oil. And the main reason I want to point that specific well out, if we look over to the location map, the Aspden Number 3 is in Section 29. It would be in Unit F or in the southeast of the northwest of 29.

You can see that currently it is surrounded by eight wells. At the time it was drilled, it was surrounded by seven wells. The east offset had not been drilled at that time. So there had been -- There's seven wells around this location when it was drilled.

Q. And how good are those wells?

A. They are good wells, all of them around it. And most of them have been producing anywhere from one to two to three years before this well was drilled.

The main thing I want to point out is that Conoco has contended that there is drainage because of the high rates being pulled out. The Aspden 3 was drilled a few years later than most of the direct offsets, and it came in as a good well. You would think that if there were problems out there, it would have been affected, and we don't see any effects.

We also might note that the intervals that are perforated -- look over to the same intervals in the Binger Number 1 -- they're perforated in many of the same intervals. The correlations are not too bad between these two wells. The further you get away, some of the correlations are not great.

This is in part what I'm basing why we think this reservoir is compartmentalized. If it was not compartmentalized and these two wells were connected somehow, you would think that the Aspden 3 would have been affected by the offset production in some manner.

Q. And you can look at these logs and see they are, in fact, completed in the same zone; is that not correct?

A. Yes, in similar zones, yes.

Q. And it appears from their production profiles that they are not interconnected?

A. Yes, and engineering testimony will go into that later.

Q. Are you prepared to go to your next cross-section?

A. Yes, sir, I am.

Q. Let's go to Exhibit Number 5, cross-section B-B', and it is also in North Dagger Draw, I believe.

A. Again, this is a structural cross-section. This is structural cross-section B-B' in North Dagger Draw, again over the Canyon dolomite section, or Upper Penn. It's laid out the same way as the first cross-section.

Q. Now, are these similar wells to wells that appeared on the Conoco cross-section in May of this year?

A. Yes, in the Examiner hearing this is a -- It's not exactly the same, but it's pretty close to the same trace of a cross-section that was presented by Conoco.

And their cross-section, if we could move in on their well on the far left-hand side, Conoco's Savannah State Number 1 in Section 32 of 19 South, 25 East, you can see that it's got two sections of dolomite, and it perforated in the upper section.

They alluded to that over in Section 28, the Yates State K 3 and the Hinkles, on the right-hand side of the cross-section. And Section 28 is an overproduced area. In fact, it's one of the bigger over- -- more overproduced areas.

These zones are produced in similar stratigraphic intervals, and Conoco alluded to that this interval within the dolomite in their well was thicker than what showed up in Section 28 in the Yates wells. So they concluded that Yates, since they had a thinner zone and Conoco had a thicker zone, and Yates had been overproducing, that they were draining the Savannah State Number 1 from Section 28.

Well, I'd like to -- Let's look down at the location map. The Savannah is in Section 32 in the northeast-northeast. The closest Yates well in Section 28 is the State K Number 3 in -- I believe it's Unit J. It would be the northeast of the southwest. That well is almost three-quarters of a mile away from the Savannah State Number 1.

If there's drainage -- and Yates contends that there is not -- if there's drainage, you would think three-quarters of a mile away that Section 29, the wells that Yates has in 29, would be draining the Savannah State Number 1. And that same interval is similar thickness as the Savannah State Number 1. So...

Q. In fact, Mr. May, if you were concerned there was drainage, wouldn't you have to drill a protection well?

A. Exactly right. If you look at the Yates acreage in 28 and 29, there are no direct offsets to the Savannah State Number 1.

So if there's drainage -- and we contend there is not, but if you believe Conoco, you could almost put forth the idea that Conoco could be draining Yates' acreage.

And they also -- If you remember my dolomite map, they're on the thin edge of the dolomite. The two Joyce wells in the northwest quarter of Section 32 have very thin dolomite sections, and their productive intervals are even thinner than the Savannah State Number 1.

Q. Let's go to the cross-section in South Dagger Draw, C-C', and I'd ask you to review that, please.

A. Again, it's a similar-type cross-section. This is C-C'. It's in South Dagger Draw. It's basically down in -- It runs from the west on the left-hand side, in 34 of 20 1/2 South, 23 East, over to the right side, to the east, in 35 of 20 South, 24 East. And again, it has a location map in the lower right-hand corner.

This area of the Canyon dolomite is a little bit different from North Dagger. It's higher structurally than North Dagger Draw. In the upper part of the dolomite -- It can also be thicker in some areas down here. In the upper part of the dolomite, the production can be more predominantly gas and water.

In the lower part of the dolomite, which this cross-section shows is where the oil and water production are at -- In other words, whereas in North Dagger Draw the oil-productive zones are in the upper part of the dolomite, in this area the oil-productive zones are in -- near the base of the dolomite.

Going through the cross-section, on the far left-hand side the Conoco Preston Number 3, 34, 20 1/2 South, 23 East, this well was recently drilled by Conoco, and I don't have any completion data on it.

The next well is the Yates Diamond "AKI" Federal Number 1 in Section 34 of 20 South, 24 East. This was a very good well for Yates. It IP'd for over 1300 barrels of oil.

The next well is the Conoco Preston Number 5 in Section 34 of 20 South, 24 East. It was a good well for Conoco. It IP'd for about 482 barrels of oil.

And then our last well on the cross-section is the Conoco Preston Number 1 in Section 35 of 20 South, 24 East. This is an older well that was originally drilled by Hanks and it was completed near the bottom, but it completed in a gas zone. It IP'd for 1.3 million and very little oil, from what I understand.

Q. Now, when you look at this cross-section, do you see any evidence of compartmentalization when you look at this exhibit?

A. Again, going back, looking at the Preston Number 5, you can look down at the IP at the bottom. They IP'd it in 9 of 1993. The Yates well was IP'd in 3 of 1996. And the Yates well originally -- We had problems again with topography, that BLM would not give us an orthodox location, came to a hearing, we were contested by Conoco, and we received a 30-percent penalty.

So we drilled the well at the unorthodox location with the 30-percent penalty and IP'd it for over 1300 barrels and then thus cut it back to around 900 with the 30-percent penalty.

You'll note that the completion dates between the Conoco well and the Yates well was about two and a half years. Again, as close proximity that they are to each other, if there is -- you would think that if there's drainage occurring, the Diamond well might have seen some effects from the two-and-a-half-year production of the Preston Number 5. As you can see, it was an extremely good well.

The other thing we might point out on the -- Going from the Preston 5 to the Preston 1, I'm having trouble correlating, as you can see. I could make some correlations, but I didn't feel confident about them. So sometimes throughout this area you'll see your stratigraphic markers are hard to carry.

But even if you could carry them, note that the other -- the Conoco Preston Number 5 and the Diamond Federal Number 1 are oil-productive near the bottom. The Preston Number 1 is gas-productive near the bottom. And again, I think that supports the compartmentalization.

Q. Mr. May, the Division Order entered in these cases defined these pools as being in, and I quote, an extensive continuous dolomite reservoir. Do you agree?

A. Yes, it is definitely a continuous dolomite body. I wouldn't go so far as to say it's a homogeneous continuous reservoir.

I feel like that there is compartmentalization, not only based on the geologic data, but engineering data that will follow my presentation.

Q. The Division also found that there was good vertical permeability in both of these pools. Do you agree with that?

A. No, I do not.

Q. And why not?

A. There can be some vertical permeability, but as I showed out in some of the earlier -- Some of the earlier cross-sections I should have pointed that out. As we DST'd different zones -- We have had some wells in North Dagger specifically for the very top dolomite section. We would drill into the zone, stop, run a DST and recover nothing but formation water. We would again go back to drilling, drill the next zone up, test it separately from the first one and encounter oil and water. And then we could maybe drill another one or two zones that would test oil and water and then get into nothing but water. To me that says they're not very well vertically communicated.

The other thing too, Conoco in the earlier Examiner hearing stated that there's some shales as you get to the edge of the dolomite, there's shales that come in that can act as vertical barriers, and I believe that, I agree.

But there's also tight limes that you find within the dolomite, not necessarily on the edge. You can find these sometimes in the thickest part of the dolomite. These act as vertical perm barriers. And also tight dolomites, we have seen. Many of those DSTs I have just described in the same well were separated by tight dolomites, and I feel like that tight dolomites can act as vertical perm barriers.

Q. Are you seeing vertical separations in the reservoir?

A. It appears that way, yes. In fact, some of the zones appear to have different oil-water cuts.

Q. Is this a common occurrence in the reservoir?

A. We see it a lot.

Q. Do recent wells demonstrate that?

A. Yes, the Polo 6 in -- I believe it's Section 10 of 19 South, 25 East, was a specific well where we drilled into the very top of the dolomite, DST'd and got nothing but formation water. And I believe the second test recovered nothing but formation water. The third test, we finally recovered oil and water.

Q. Based on your geologic study of these pools, what conclusions can you reach?

A. I believe that it's a very complex body of dolomite, and we feel that it is compartmentalized because of some of the production characteristics in what we've seen on logs and other geologic data, and -- Well, it's just one of the most complex reservoir bodies I've ever encountered.

Q. Were Yates Exhibits 2 through 6 prepared by you?

A. Yes, they were.

MR. CARR: At this time, Mr. LeMay, we would move the admission into evidence of Yates Petroleum Corporation Exhibits 2 through 6.

CHAIRMAN LEMAY: Those exhibits will be admitted into the record without objection.

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

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. May, do you have a copy of the Division Examiner Order?

A. I think it's under here.

Q. I've turned your copy of the Examiner's Division Order to page 8, and if you'll flip back you'll see that these were his findings with regards to the North Dagger Draw. Some of these findings on page 8 obviously cross over into engineering conclusions, but I wanted to go down the list on 8 and have you show me points where you would disagree with those findings.

I think in A, Mr. Carr has helped you identify one point where you have a difference, and that is the last part where the finding is, there's good vertical permeability. But for -- but for that, differs? Is there anything else in Finding A there for which you have disagreement?

A. Can I take just a minute?

MR. KELLAHIN: Absolutely.

MR. CARR: That's page 8, Tom?

MR. KELLAHIN: Page 8, it's Finding 9, sub A.

THE WITNESS: With the exception of the vertical permeability in general -- that's the main thing I would object to, would be the vertical permeability.

Q. (By Mr. Kellahin) All right. In Finding 9 B do you have any disagreement with that finding?

A. I agree that it thins -- well, no, I don't -- Well, it does thin to the southeast, but I don't necessarily agree that the dolomite is thickest along the top of the structure. I don't think you can make that statement in general. Yes, there are places where that does occur.

Q. How would you get at that?

A. I would say at -- sometimes the top of the structure coincides with thicker parts of the dolomite, sometimes.

Q. All right. I'm particularly looking at the violation area in that particular portion of North Dagger Draw with regards to this next finding. Is this a correct statement from a geologic perspective, from your analysis, on 9 C?

A. As far as the pressure, I can't address that. But as far as -- I don't believe that I would agree, again, with the vertical permeability. I agree that there are vugs and there are fractures present in that. A lot of times, the vugs is one of the major porosity systems within the dolomite.

Q. All right. What about horizontal communication in a geologic sense?

A. There can be, but not for great distances, I don't believe, because I believe in the compartmentalization.

Q. Characterize for me what you think geologically is the extent of this compartmentalization within the violation area in that vicinity of North Dagger Draw.

A. It's hard to say just using geologic data --

Q. Uh-huh.

A. -- because I think that the compartmentalization is based off some of the productive facies within the carbonate bank, and those are hard to identify on electric logs. But the engineering data that will be presented later will help with that.

Q. All right. I'm going to show this to you to help you locate what I'm describing. It was Mr. Fant's exhibit from the Examiner hearing in which he identifies 11 wells that are interfering with each other within the general area of the violations. I'm going to show you so you see the wells I'm looking at.

We'll talk about the engineering aspects with Mr. Fant later, but I wanted you to see if there's a geologic explanation to his conclusion of interference with these wells.

Do you need a locator map, Mr. May?

A. No, sir.

Q. All right.

A. And your question was -- ? I'm sorry.

Q. My question is, the magnitude and extent of compartmentalization within this violation area doesn't seem to fit, at least yet, with what Mr. Fant told me at the Examiner hearing where there are 11 wells which -- and it may be simply two that interfere, and then there will be some other portion of that where he's got two or three that are interfering with each other's production.

How does that occur within your analysis of this compartmentalization concept?

A. Some of the compartments may be as small as 40 acres, some of them can be a little bit larger. And these compartments don't fall where the wells hit them in the center. Some of these compartments, one well may catch the side and another one may catch the other side. What Mr. Fant is showing here, that there can be some effect between two wells.

And I believe he also talked about the effect -- And he can testify to this too, so maybe I shouldn't address it.

Q. My point is, do we have the ability to design rules that will accommodate the compartmentalization of the reservoir in North Dagger Draw?

A. I think as far as specific compartments, it's going to be very hard, but it should be addressed and viewed in the total picture on how this field should be developed.

Q. Other than what we're doing now, at this point in the life of the reservoir you don't see any material way to change the method by which we establish and use rules for the pool, other than this debate about the rate?

A. Well, we feel like that -- and engineering testimony will back this up. We feel like that producing at the higher rates will not infringe on correlative rights.

Q. Okay, I understand that point of view. Yet we've got examples in the violation area where a 40-acre offset, in fact, is interfering with the production of its adjacent 40-acre well.

A. It was also pointed out by Mr. Fant that some of those wells were affected, that if the second well hadn't have been drilled, a vast majority of new oil would not have been recovered. So there was just some interference between the two wells, not total.

Q. You're pointing to some examples of such instances as that. You're looking at 29 in the northwest quarter with the Aspden 3 well. I think that was on --

A. (Nods)

Q. Yes? I think that was on your cross-section.

A. Yes, it was on my cross-section.

Q. And I've forgotten which one it was.

A. Which cross-section?

Q. Yes, sir.

A. It was cross-section A-A'.

Q. The A-A' cross-section?

A. Yes.

Q. I looked at that real quickly. I didn't see any pressure values for that well on the cross-section. What did you discover?

A. Mr. Fant will address the pressure.

Q. So he's got pressure data on that well, and we can see what --

A. He will address --

Q. -- the pressure data is?

A. -- the engineering part of that.

Q. All right. Geologically, help us understand in a summary fashion the distribution of reservoir fluids between South Dagger Draw and North Dagger Draw.

A. As far as gas, oil, water?

Q. Yes, sir.

A. Are you talking about oil-water contacts?

Q. No, sir, I'm just talking in a general sense about the distribution of the gases and the fluids.

A. In general, North Dagger produces mostly oil and water. In South Dagger, parts of it, it's the same thing, but part, other parts, you can have gas produced, gas and water produced along with oil and water, and then other parts of South Dagger, on the far western side, there are some wells that currently are just producing gas and water.

Q. In North Dagger Draw there's enough information, and the operators are getting pretty good at staying above that interval that is substantially watered if you penetrate it?

A. In some of the more developed areas, yes, you have enough data that you feel a little bit more comfortable with. Getting over on the northeast side, that varies on you pretty quickly. And even some of the -- We've been even surprised in some of the more established areas. Some wells you could go 10, 20 feet, 30 feet, sometimes lower, than some of the surrounding wells.

Q. I don't want the Commission to misunderstand the distribution of fluids in the reservoir. Am I correct in understanding that if you perforate in the upper portions of the dolomite you're going to produce oil, but also there's inherently water in that interval?

A. You always have water production. But there are some wells in the very top, over in North Dagger, where we have seen nothing but water production.

Q. This is not an active water drive reservoir in the North Dagger Draw, is it?

A. Not that I'm aware of, no.

Q. I think the rest of these findings on page 8 deal mostly with the engineering aspects. We'll talk to Mr.

Fant about those.

But if you'll turn the page for me, let's go down the findings for South Dagger Draw, and show me any instances where you have a disagreement with the Examiner's finding, starting on page 9. And I'll just let you take a moment and go down those, and tell me those ones where you disagree.

A. Again, the vertical permeability I don't necessarily agree with.

And as far as a gas cap to reach -- I'm not sure I agree with the statement in 9 A, on the bottom part, about gas-cap gas being able to reach perforations in wells that would normally be limited to production to the oil column.

Q. All right, sir. I've made a note of that.

A. 9 B, it says the oil column is overlaid by a gas column of varying thickness, regardless of structural position within South Dagger. I think there is a structural content to where the gas is at.

Q. All right, sir.

A. As far as the drive mechanisms, I would feel more comfortable leaving that up to engineering.

Q. Okay.

A. And pressure, I can't address pressure, on 9 F.

Q. And the rest of those look to be engineering questions?

A. Yes.

Q. All right. I want to make sure I understand the compartmentalization concept here. Are you telling me there is no pressure communication between the compartments? You're not saying that, right?

A. You'll have to address pressure with the engineering testimony.

Q. All right, if there's a difference in pressures, then there is a weakness in the barrier between the compartments?

A. Yeah, and I'm going to leave that to the engineering testimony.

Q. Okay. But do you geologically have a way to determine the integrity of the compartment container, whether it would be a barrier to any type of flow?

A. As far as some of the cross-sections I showed and some of the offset wells, good wells that were drilled later, I infer from that. But a lot of it is based off engineering testimony, but I make inferences based off my geologic knowledge of the area.

Q. That's really what I'm asking you. The assumption is, the engineer comes to you and he finds a newer well that has lesser pressure than he might otherwise expect, and he says, Well, the pressure went somewhere. Is there a geologic explanation to where the pressure went?

And you can say, Well, you were in a compartment with another well. I guess that would be one way to approach it. But you can't map the compartments?

A. No, I cannot map the compartments. They're very hard to identify on electric log; you need cores. And we can't go out and core each well. And anyways, as far as the development of the field, there's no need to do that when you have the engineering data.

MR. KELLAHIN: Okay. Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Thank you.

Questions of Mr. May?

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. How big of an influence do you think the evolving drilling and completion techniques that Yates must have developed over development of this field had on the IPs for the wells that you showed?

A. I think all the operators gaining knowledge and experience through developing the pool have learned better and better techniques. So yes, I think that has an influence on the higher IPs. But also in North Dagger -- You can't account it to all of that. I think in North Dagger where we have found some of the really good wells, we have some very good reservoir rock there, excellent reservoir rock. It's got some good holes in it to store a lot of oil and move a lot of oil.

Q. But yet with a good reservoir, if there are poor drilling or poor completion techniques, that can impact the IP and the production?

A. Yes, poor completion techniques, that can be a factor on your IP. Yes, it sure can.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. I have just one. It has to do with the same subject, the initial producing rate. Is that the maximum producing rate? Are the wells pumped off at the time those are measured?

A. I don't think they are, but Mr. Fant could probably better address that question, but I think at the time some of them may not be pumped down.

COMMISSIONER WEISS: That's the only question I had. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Standard question, Mr. May: Do you think this is the oil rim to Indian Basin, then, the North Dagger and South Dagger Draw fields?

A. That's a possibility. Now, whether the rock is continuous all the way down into Indian Basin -- Of course, Indian Basin has been classically the gas producer. Now, that's probably not a bad assumption, but you can't assume that everything is homogeneous from one end to the next of this dolomite body. And whether it's actually the oil rim, North and South Dagger, it's hard to say, but it's possible.

Q. Well, if it was, would this be an associated field, this whole complex then?

A. Well, if it was, I would assume so, yes, sir. But the thing of it is, I think -- You recall Indian Basin had been producing for numerous years before South Dagger came on, and a lot -- we didn't see in South Dagger influence from all that gas taken out of Indian Basin, an influence on South Dagger. So I don't know if I would be willing to step out and say that it's definitely an oil leg to Indian Basin at this point, but it's possible.

Q. You mentioned submersibles. Is that the way Yates completes their wells, putting --

A. For the most part, yes, sir. If we have a high-rate well we use submersible pumps to move that fluid because from what I understand from engineering, if you don't get the wells pumped down adequately you have higher water cuts, and the beam pumps just can't handle some of the fluid amounts.

Now, when some of the wells settle down and get below that, sometimes we will switch over to a beam pump.

Q. Are you familiar at all with the Bough C up in Lea County?

A. Not a whole lot, but I at least know of it. But I've never worked it myself.

Q. Well, I think -- they're recent -- You mentioned a time frame of submersibles coming in at the 1970s. A lot of that development, wasn't it due to submersibles from the 1960s up there?

A. That may very well be. I don't know that, Mr. Lemay.

Q. Are you familiar with the Hanks operation at all?

A. Just a little bit, a little bit through the history and everything, and I know he had --

Q. Do you know how his wells were completed and produced?

A. I think he completed them -- I don't believe he used submersibles, because I don't know if they were quite accepted at that time. But he used some -- and I'm not too familiar with them, but he tried different types of pumps to try to move larger volumes --

Q. Are you familiar with his gas-lift operation down there?

A. I've heard a little bit about it, yes, sir, and I guess that was probably one of the things he tried, to try to move fluid. And he was -- Some of the wells did okay and some didn't, he wasn't successful from what I understand.

Q. Is that engineering more or less -- Would gas-lift be an efficient way to produce this reservoir, do you think or --

A. I'd better leave that to the engineers.

CHAIRMAN LEMAY: Okay. Any more questions?

Thank you very much, appreciate it, Mr. May.

(Off the record)

CHAIRMAN LEMAY: Let's take a break and come back at 12:30, take a lunch break now.

(Thereupon, a recess was taken at 11:20 a.m.)

(The following proceedings had at 12:36 p.m.)

CHAIRMAN LEMAY: We shall continue.

Mr. Carr?

MR. CARR: Thank you, Mr. Chairman.

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. My name is Robert Fant.

Q. Mr. Fant, where do you reside?

A. I reside in Artesia, New Mexico.

Q. By whom are you employed?

A. I'm employed by Yates Petroleum Corporation.

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

A. I am a petroleum engineer.

Q. Have you previously testified before this Division?

A. Yes, sir.

Q. At the time of that testimony, were your credentials as a petroleum engineer 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. And are you familiar with the engineering aspects of the subject pools and the development thereof?

A. Yes, sir, I am.

Q. Are you the person with Yates Petroleum Corporation who's responsible for the engineering aspects of the development of the Dagger Draw Pools?

A. Yes, sir.

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

CHAIRMAN LEMAY: His qualifications are acceptable.

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

A. Okay, well -- Yeah, originally we knew that generally wells produced at high rates soon after completion. That's a common characteristic in Dagger Draw. Most of them would experience fairly rapid declines and would soon thereafter be at what seemed like to many people high rates, but for Dagger Draw are still low rates. Wells might come in at 600 or 700 barrels a day and decline down to 200 or 300 barrels a day, which is still a nice well at 200 or 300 barrels a day, but it's lower than the IPs.

But some of the more recently drilled wells in the last few years, as we moved into a different portion of the reservoir and started developing a different portion of the reservoir, the rapid declines weren't experienced. In fact, in some instances exceptionally high initial potentials were noticed and rapid declines were not seen thereafter. The wells stabilized at exceptionally high rates.

And so, you know, basically that's what -- that's you know, some of the events that started this process.

Q. Are you the individual who's been involved in discussions with the Oil Conservation Division's District Office concerning this problem?

A. Yes, I am one of the individuals.

Q. A year ago, when this problem first came to your attention, did you contact the OCD, or were you called initially by Mr. Gum?

A. Well, it was actually a little bit over a year ago at this point, and I went and contacted Mr. Gum. I basically just drove over to his office and asked -- told him that I wanted to sit down and talk about some of the stuff going on in Dagger Draw.

Q. And that's how this process with the OCD was at least first raised?

A. Yes, I believe that was the first -- That was the first involvement I know of.

Q. Were you also involved in the meeting which occurred with the District Supervisor in April of this year?

A. Yes, sir, I was.

Q. Now, that meeting was initiated by Mr. Gum, was it not?

A. That meeting was initiated by contact with, I believe, Mr. Brian Collins, our -- The man who had just became operations manager with Yates Petroleum, Mr. Gum contacted him and asked him to ask Brian to have us bring a recommendation of how to take care of this matter.

Q. And what was that recommendation?

A. Well, we met with him in April, and we -- when we met with him, we proposed to restrict the production from those spacing units to 700 barrels of oil per day or less, you know, because hitting an exact number is a very hard thing. But we said we would put them at 700 or less, so as not to accrue any more overproduction.

We would, as rapidly as is legally possible, pursue the remedies, because we believed at that time that the allowables should be increased and that the overproduction should be canceled. So the only method for us to do that was to file an application with the OCD to have that done.

Q. When an operator finds himself overproduced, what can he do?

A. You can live with the rules and make it up, or if you feel that the rules are wrong, you can seek the relief of the Commission.

Q. And are you not doing both of those now?

A. Absolutely, we are.

Q. Have you prepared exhibits for presentation here today?

A. Yes, sir.

Q. Could you refer to what has been marked for identification as Yates Exhibit Number 7, identify that and review it for the Commission?

A. Exhibit Number 7 is a plat I prepared basically showing North Dagger Draw and wells within North Dagger Draw. It is basically on a scale of one inch is equal to a half a mile, and it shows basically the proration units within the field.

And Conoco has -- It's got many colors on there. There's a dark bold outline that, if you'll notice, compares very close to the dark black outline shown on Exhibit 1. It's basically the boundary of the dolomite facies of the reservoir. At this point I'm looking primarily at North Dagger Draw.

And there is a color coding for this particular map. There are two shades of green on this map, there are two shades of red, there are two shades of blue, there are two shades of magenta, and there are two shades of gray for these proration units. The Yates Petroleum-operated spacing units are in green, the Nearburg Producing spacing units are in magenta, Conoco's are in red, Texaco in blue and Mewbourne's are represented by the grays.

It's been expressed -- It was expressed in the

Examiner hearing, and the point was kind of brought across, that this is the only area that's ever overproduced. And what I wanted to show you on this particular map was, the darker shades -- All right, let's just take the green, for example, with Yates Petroleum. The dark green represents spacing units that have at one point in history overproduced. I'm just being totally frank about that. They have at one point in history overproduced.

The dark blue for Texaco represents where they overproduced. The bold red represents where Conoco has overproduced a proration unit at some point in history. And the same with Nearburg and Mewbourne.

And what you'll see is, basically every operator out here at some point in history has overproduced a spacing unit.

Q. What percentage of the Yates spacing units have been overproduced at one time or another?

A. Approximately 49 percent.

Q. And what about Conoco?

A. Conoco, the numbers are 11 of 16 proration units that they operate have at some point overproduced, which is 69 percent.

Q. And as an average for this whole -- the area shown in this exhibit, how many of the spacing units have actually been overproduced at one time or another?

A. Basically 50 percent have overproduced at some point in history.

Q. Now, Mr. Fant, you're not offering this exhibit to suggest that other operators have been overproduced to the magnitude of the problem the Division is looking at here today, are you?

A. No, the magnitude of the overproduction in these other wells does not approach this, and I do not want to convey that in any way.

Q. But this is the production pattern in this field which was sort of the first step down the road that has led to this problem here today; is that not true?

A. Absolutely, that's one of the things I'm trying to show here. We have stated before that the practice has been to overproduce the wells early in their life and then allow them to make it up through decline. And -- It's been done throughout the field.

It also shows that basically the allowables as they were set have never really reflected well capabilities. I mean, they were attempting to. That's what Conoco presented them to be, that's what Roger Hanks presented them to be. But really, it hasn't been the case.

And I really want to stress very strongly that, yes, the magnitude in this area is greater, the wells in this area are better, the reservoir rock in the area that we're talking about today is significantly better than these older proration units to the west. We're dealing in a situation where it's not just the production practices, but it has to do with why the wells are producing that much better, and it has a lot to do with the rock.

Q. Will you be presenting information about these pools here today? That is, new information or something that really wasn't known before?

A. Well, not really. I mean, early in the life -- I'm going to review a lot of the data that we've known about this field, since early in the life of the field.

We've known since the days of Roger Hanks that large volumes of water were produced with this field, and it's been a generally held principle since the early days of this field, the 1970s, that you get better oil cuts at higher producing rates. That was part of the tenets of what Roger Hanks was saying. That's what Conoco presented in 1991.

But what I am going to say is, I believe we have a better understanding now of why the reservoir produces the way it does. And it is -- You know, it's very important to me as an engineer to develop a model. And what I mean by "model" here is not a reservoir simulation but just a visualization, an understanding of what's going on in the reservoir, you know, a mental model of the reservoir that accounts for absolutely all of the known data that we have.

If we don't account -- If we account for one piece of data but can't account for another piece of data, then the model is wrong. And it's important to me to develop a model that accounts for all the data, all the things we know to be facts, because if you don't do that, then you're fooling yourself. And --

Q. Now, Mr. -- Excuse me, go ahead.

A. No, go -- That's basically all.

Q. All right. When did the greatest production increases actually occur in this pool, or in these pools?

A. I'm going to have some exhibits, an exhibit, later that will show that the greatest production increases occurred around 1990 to a peak in 1992, the reservoir went on decline -- or the field went on decline, and then drilling began in 1994, and we started developing what is this area right through here, and we have reached a new peak, or actually -- I don't know that we've actually reached the peak, but we have experienced another significant increase in oil production.

Q. Let's go to your Exhibit Number 6, your oil cut comparison, and I'd ask you to identify and review the information on that exhibit for the Commission.

A. Okay, this is Exhibit 8.

Q. I'm sorry, it is Exhibit 8.

A. Okay, one of the first things I want to try to lay out for you is to establish a relationship between producing rate and oil cut. Okay? And I'm going to illustrate that through several exhibits here.

What we are looking at here on Exhibit Number 8 is a plot of what I call swabbing oil cuts versus second-month producing oil cut for 58 wells in Dagger Draw. These are primarily some of the more recently drilled wells, since, say, 1992, 1993, 1994, but primarily more of the recent ones. These don't incorporate, say, the early wells that were drilled by Roger Hanks.

And on the X axis we have the swabbing oil cut for the well, okay? And on the Y axis we have the oil cut as reported, as calculated from the production in the second month of production for the well.

Q. Now, why did you use the second-month reported production?

A. Well, I wanted to get early time data in the life of the well, I wanted to be looking at oil cuts in the early life of the well, but the first month of production is sometimes not a full month, it's sometimes inaccurate data. Sometimes the water volumes are being placed into a tank and don't get properly reported, but the second month is properly reported. So I wanted to be representing accurate data here.

Q. And what does this exhibit actually show?

A. Well, what you need to understand is that when you are swabbing a well, after completion, you're producing that -- you are producing that well, but you're producing it at what is, for Dagger Draw, very low fluid volumes, you know, let's say -- about 500 barrels a day is about all you can swab. For Dagger Draw -- And that's 500 barrels of fluid a day, oil and water. And you're swabbing, and that's a low drawdown. We normally can not get the fluid levels down very deep.

The second month of production represents what the production is like when we have a submersible pump in the well, producing it at high volumes. If there was no change in the oil cut between when we're swabbing the well and when we're producing it at high rates, these points would cluster around this diagonal line going through here.

Well, what you can see here is that most of them are significantly above the diagonal line, illustrating that we get a much better oil cut when we're producing at the high rates afforded to us by submersible pumps than the oil cuts we get when we're swabbing the well. In other words, we're pulling out more oil for every barrel of total fluid with the submersible pump at high rates than we are with a swab at low rates.

That's basically what this is designed to show, that at higher rates, we're getting a higher oil cut.

Q. Let's go to Exhibit Number 9. Would you identify that, please?

A. Okay, Exhibit 9 is a series of selected -- 17 plots from selected wells in North and South Dagger Draw. My analysis here, there's a lot of it that focuses on North Dagger Draw, but there are examples that are in South Dagger Draw.

These are, quite honestly -- These wells that we're going to look at in this exhibit are some of the best wells in the field.

Now, what I'm showing for you here is the oil cut in these individual wells as a function of the producing rate in the well, okay? Producing rate along the X axis, the oil cut along the Y axis. And we will have 17 of these wells.

This involves -- These plots incorporate data from actually ten of the overproduced wells on ten of the overproduced units, and these are some of the more recently developed -- recently drilled wells. These plots cover areas in North Dagger Draw from, you know, this area up in here down to -- well -- and also wells down in this area in South Dagger Draw. So I'm trying to illustrate to you that this phenomenon not only exists in North Dagger Draw, but it exists in South Dagger Draw.

And what I've done here is, I've taken the monthly producing data for the well and looked at it, and I take -- I calculate the oil cut for that month and plot it versus the oil rate for that month to see whether at the higher rates we had higher oil cuts.

And if you'll -- you know, thumbing through -- I'm not going to go through each one of these individually, but I will represent to you that all 17 of these, a statistical regression of the data, just doing a linear regression of this data, gives you a positive slope.

In other words, at higher rates, over the life of the well, over this portion of the life of the well, at least, at the higher rates we are producing at higher oil cuts. And it -- All 17 of these wells have a positive slope.

This illustrates that the pool is rate-sensitive, from the standpoint of water production. If we produce these wells at low rates, we are going to be pulling out excess water, excess reservoir energy, and we will lower the ultimate recovery of the pool.

Q. Let's go to Exhibit Number 10. Will you identify and review that?

A. Okay, Exhibit Number 10 is kind of tabulated data on the same type of analysis I did for these 17 wells.

These 17 wells are examples. But I want to tell you right now that I studied every well, and I did these calculations for every well in Dagger Draw for which I had data. Not only Yates wells, but Conoco wells, Marathon wells, Santa Fe wells, for every well that I could get data on, basically from the public data records. And you could go in and plot -- do a statistical regression of oil cut versus oil rate.

Now, on Exhibit 9, the previous exhibit, we had a positive slope on those exhibits. And what we have on Exhibit 10 is a table with the first column being the well name; second column, operator; the next four columns giving the location of that particular well; and then the -- What was it? The seventh column is what I term oil-cut slope. That is the slope of this line, like you see on this Exhibit Number 9. I did not want to present 280 of these plots to you; it would get overbearing. But here's the data from it.

Now, it's very important to understand that 95 percent of the time, on this analysis, that that slope is positive.

Q. Mr. Fant, this slope was determined by using statistical regression, I think is what you said?

A. Yes, sir, a linear --

Q. Is that just a mathematical process by which you determine whether you've got a positive or a negative slope?

A. Yes, it is simply a mathematical process. Any number of mathematics books will -- you know, can illustrate how that is actually done.

Q. Now, five percent of the wells, you -- if I understand what you've said, did not show a positive slope; is that right?

A. That's absolutely true.

Q. Do you have any idea why that would be?

A. Well, you know, I went in and looked at some of those, and I believe that it has to do with statistical aberrations due to what is termed in the mathematical sense outlier data points. And later on in my presentation I will show you an example of what can cause that to happen. I believe that the -- most of the negative slopes -- you can look. There's a few on the front page.

The Afton 2 has a -- you know, a 2 times 10^{-5} slope. That's very small negative slope.

The Binger 2, -7 times 10^{-5}.

The Binger 1, -8 times 10^{-6}.

These are very small numbers. These are very, very small negative slopes, and they are caused primarily by statistical aberrations that I will -- I will illustrate for you later why that occurs.

Q. All right. At this point, why don't we move to Exhibit Number 11. Are you ready to go to that?

A. Sure.

Q. Could you identify and review that, please?

A. Okay, Exhibit Number 11 is basically the same type of plots that we saw in Exhibit Number 9 for two wells, the difference being, Exhibit Number 9 was based upon data over several months to several years of the life of the well. In other words, it took into account some natural decline on the wells.

And people might try to say, Well, that's just a decline effect. But what I wanted to illustrate with this is, we have the same type of data plots for two wells, one in North Dagger Draw, one in South Dagger Draw, that shows that this phenomenon of higher oil cuts at higher oil rates, or higher producing rates, is an instantaneous function also.

And when we look at the first one, the Diamond "AKI" Number 1, this is a well -- Mr. May has already mentioned this well. This well was drilled at an unorthodox location, has a 30-percent penalty on it. As a result, we needed to know what the -- it's 30 percent off of the IP.

We placed a pump in the hole, and that pump was producing around 800 barrels of oil per day. But you see there's a cluster of points on the first one, kind of on either side of 800 barrels a day, and that cluster of points was when we first put a sub pump in the hole.

One of the interesting things you can do with a sub pump is, you can put what's called a variable-speed drive unit on it, and you can actually spin it faster, and that pump is capable, then, of producing higher volumes of fluid.

So we put a variable-speed drive on it, turned up the production rate and increased the production in the well to approximately 1300 barrels of oil per day. That's the two points there, over on the right, at about 35 percent oil. If you'll notice, the 800-barrel-a-day rates were around 28, 29, maybe 30 percent.

We turned this well up to 1300 barrels of oil per day -- Now, this is in South Dagger Draw, so that's still within the allowable limit. We turned it up to 1300 barrels a day, the oil cut went up to 35 percent. And actually we stepped it up there. We had a few data points around 1100 that were about 32-percent oil. The allowable was set to about 900 or 950. I don't remember the exact number. And so they turned the well's production back down, to comply with the allowable. And you can see that right around the 900-barrel-a-day range, the oil cut simply dropped right back to 30 percent.

So basically what --this shows that this well, as we turn it up, as you increase the rate on this well, the oil cut improves. Or in other words, we're pulling less water out for every barrel of oil. It's a very important premise. We're taking less energy out of the reservoir for every barrel of oil produced, and therefore we are recovering -- we will, over the life of the well, at higher rates, recover more oil.

The second plot is simply the same type of plot for the Aparejo "APA" Number 5. This particular instance, it was not a submersible -- it was not putting in a variable-speed drive unit; it was actually running a different size pump to create this data.

But as you can see here, at very low oil rates we almost got no oil. I mean, we were at the 5-percent -- 5 to -- less than 5-percent oil cut on the second one. And as we raised the rate up, we're upwards of 12 percent, a very strong relationship between the oil cut and the producing rate.

It's very important, and in all reservoirs it's an accepted premise that you want to take out the least amount of water that's possible.

Q. Now, Mr. Fant, at the 1991 Division hearing on Conoco and Yates's applications to increase allowables in these pools, Conoco's engineering witness testified that increased allowables and higher producing rates in the reservoir resulted in better water cuts.

Have you seen anything in your study that would cause you to disagree with that statement as it applies to the reservoir today?

A. No, he was right then, and it was known then, and that was one of their premises for raising the allowable at the time, is to -- is because you get better -- he terms it in better water cuts, I term it in better oil cuts, but it's the same concept. You want to minimize the amount of water withdrawn from the reservoir.

Q. Let's go to your Exhibit 12. Would you identify that, please?

A. Okay, Exhibit Number 12 is actually a plot of the same two wells that we were dealing with in Exhibit Number 11, but in this instance we're dealing with -- instead of the oil cut, we're looking at the GOR of the well, as plotted against the producing rate in that well.

And what this shows, clearly and pretty strongly, is that as we produced at the higher oil rates, we produced at a lower GOR in the well. And both wells show that very clearly. And, you know, these particular plots of GOR have a negative slope. And, you know, this is a on an instantaneous basis.

Q. Now, let's go back and refer back to Exhibit

Number 10. What does this exhibit tell you about the relationship between high production rates in these pools and the resulting gas-oil ratio?

A. Okay -- Yeah, Exhibit 10 is the table of the wells that I talked about earlier.

The final column on the right is what I term the GOR slope. I did the same type of statistical regression on the data to determine what the slope is for the GOR, and 75 percent of the time the GOR slope is negative, as we would expect it to be.

You know, so we've shown that with oil cut and with GOR, over history producing the wells at higher rates improves those two aspects, the GOR and the oil cuts. And we've also -- Also the data shows that if you just go out there and change the producing rate day to day, it improves the GOR, and it improves the oil cut on a day-to-day basis.

So not only is this a phenomenon that occurs over time, but it's also a mechanism that occurs on an instantaneous basis in the reservoir. And this -- I do want to say, the instantaneous basis is related to new wells. You know, this is basically the first few days of production, of the Diamond and the Aparejo 5.

Q. Now, Mr. Fant, in 1991 Conoco's engineering witness testified that at higher producing rates he felt no secondary gas cap had developed. Do you agree with that still today, based on what you know of the reservoir?

A. Absolutely.

Q. He also testified that at higher rates the gas-oil ratio was no higher than at lower rates. Do you agree with that?

A. Yeah, I agree it's no higher. In fact, the data clearly states that it's actually lower.

Q. Have you studied well-interference data in these pools to determine the appropriate number of wells for each 160-acre proration unit?

A. Yes, sir, I have studied that very heavily. In fact, it's been the primary focus of my professional life for the last 18 months.

Q. Why don't we turn to what has been marked as Yates Exhibit Number 13?

A. Okay.

Q. Would you identify and review that, please?

A. Exhibit Number 13 is a plot of rate versus time, and I have it entitled -- The first page is entitled Withdrawal Comparison on oil Production, the second page is Withdrawal Comparison on Gas Production, the third page is Withdrawal Comparison on Water Production, and the fourth page of that is Withdrawal Comparison on total Fluid Production.

Most of the interference data that I have studied in this pool has been related to production of the wells. If interference occurs between wells, then essentially the decline rate of one well is affected when another well begins producing.

That is -- And I want to point out at this point that interference is not a function of rate. If it's going to occur, it doesn't matter what rate you're producing at, it's going to occur. That's a fact. That's a principle. If there's a conduit for interference to occur, it's going to occur, period.

But I'm not going to sit up here and say there's absolutely no interference between wells in this field. And in fact, this particular exhibit, Exhibit Number 13, is an illustration of where interference has occurred between two wells. I have studied interference data basically throughout these two pools, from North Dagger Draw to South Dagger Draw, and to submit all of that data would be beyond -- we would not have time to put all that in. But I want to illustrate for you an example where we do have interference.

We had drilled the Warren "ANW" Federal Number 1. In February -- It was completed in February of 1995. It's represented by the squares on this first plot. And as you can see, in June of 1995 the Thomas "AJJ" Number 6 was drilled.

Now, as you can see, the Thomas -- What this thing shows is, the lower line on this plot is the production from the Warren "ANW" Number 1. The line with what is actually diamonds on it is the -- and it's the next one above the Warren -- is -- and it's a line that actually begins in June of that year -- that's the Thomas 6. And then the line with the circles, dots, above that, is the sum of the two.

Now, what's happened here is, when we drilled the Thomas 6, there is communication between the Thomas -- some -- partial communication between the Thomas 6 and the Warren 1. That's a fact.

As you can see, as soon as the Warren Number 1 was put on production, the next month the decline in the Warren Number 1 changed. It went to a steeper slope.

One of the nice things about engineering data, though, is that we can calculate how much additional oil is being recovered by the Thomas 6 and how much of the oil is actually being -- is involved in this interference between the two.

If you want to look at the second page, you'll see that gas production was also affected. But what's kind of funny is, really water production never was affected. And you get back on the last page, you can see that the total fluid production was impacted.

Now, we see some interference between these two wells. These two wells are not in total communication with each other. Their full zones in the well are not in communication with each other. If they were, we would not be recovering new oil.

And it's very simple to come in here and do an extrapolation of how much oil the Warren would have recovered, how much will be recovered now with the two wells, and the difference between the two is how much new oil is being recovered. And the calculations show that 71 percent of the oil recovered in this Thomas Number 6 is brand-new oil, absolutely new oil.

Another point that shows why these wells are not in total communication with each other is, if they were in total communication across the zone, okay, if everything was in communication, shortly after, within a month or two after drilling the Thomas 6, both wells would be producing at essentially the same rate.

Well, you can see that the oil production from the Thomas 6 is significantly higher, several hundred barrels a day higher than the production from the Warren 1.

In other words, if we had not drilled the Thomas 6, that incremental 71-percent oil would have been left in the ground, because this well is in -- the Thomas 6 is not in communication with any other well. Therefore, if we had not drilled the Thomas 6, that oil would not be recovered. That is oil that is absolutely unique to that well.

Furthermore, I'm not saying that the Thomas 6 is taking oil away from the Warren. This is oil that the Thomas 6 deserves to recover. It's important to understand that, that waste would have occurred if we had not drilled the Thomas 6.

Q. Was this exhibit prepared for presentation in the context --

COMMISSIONER BAILEY: Bill, do you have another Exhibit 13? Mine's only a two-page on, instead of the four-page one.

(Off the record)

Q. (By Mr. Carr) Mr. Fant, was this exhibit prepared for the purpose of the Oil Commission hearing?

A. The exhibit was prepared for the original hearing. The study, this study that I did, was done back in February of 1996. So, I mean, yes, I prepared this particular exhibit for that hearing. But the study had been done much earlier. It was done before any of that.

Q. Let's take a look at Exhibit Number 14, the plat showing the area of current development, and I'd ask you to review for the Commission what this is designed to show.

A. Okay, Area 14 [*sic*] is a plat of the area -- what I call the area of new development for Yates Petroleum.

This is the same exact plat that was presented in the Examiner hearing.

I would probably say that the area of new development may extend a little bit further to the east now. We have drilled some wells further to the east that have been phenomenal.

But this was the area, the primary area of study, because this is the area we're developing under the rules of the -- Dagger Draw. And so this is primarily the area that's being impacted by those rules, and those rules need to reflect what is best for this part of the reservoir and close adjacent areas.

And what this has, there are dark lines on this particular plat that show where I have found known instances where wells have been in communication with each other, where they are -- where they have had some interference between the two.

Now, we see -- We can count up here solid lines, one, two, three, four, five -- Am I counting that right? Yeah, there are five solid lines and one dashed line. The dashed line at the time of the original hearing was what I suspected possibly could be interference. And I'm here to tell you right now that, yeah, that probably should be a solid line; I believe those two wells are in communication with each other. I'm not trying to say that there's not some interference out here, but I am going to show you from the data that it's very, very small.

Now, the question should arise, how many potential chances are there on this plat alone of interference? And I'm here to tell you that there are 137 potential paths of interference, on this plat alone, between a well and its direct offset.

And what that says is, we have six known instances and 137 possible. Well, that's a pretty small percentage, you know. Say it's less than five percent. Actually, you know, if you take six and divide by 137, you know, it's between four and five.

And if you remember, as I showed on Exhibit -- as I talked about on Exhibit 13, 71 percent of the reserves involved in this case were brand-new. When you look at all of these instances right here and look at the average, how many of the reserves are being impacted when there is some interference, only 20 percent of the reserves are being impacted between two wells. Okay?

So when you look -- when you take the fact that only five percent of the time do we have interference between wells, and then only 20 percent of the reserves are impacted in those known instances of interference, you multiply those two together and you come up with the fact that only one -- less than -- actually, it's less than one percent of the reserves in this field are even impacted by interference in this area, in this area of new development, the area of this field where the rules are impacting and, as I will show later, are causing waste.

Q. How do allowable restrictions impact the situation where there's interference? I mean, what happens there, Bob?

A. Well, as we -- as can happen in these wells, if you only have one stringer that communicates between two wells, that may be the only stringer present in one well, and the other well may have four or five stringers in it, very common case.

Now, if the well with only one stringer is allowed to produce at 700 barrels a day and the well with four stringers is only allowed to produce 700 barrels a day, then the -- within that one stringer, the well with only that one stringer in its well has an unfair advantage.

In other words, you know, that would be like being on the edge of -- If it was going toward the edge of the reservoir, the well on the edge of the reservoir would then have an unfair advantage over the person with the good well, because the good well with four stringers may be capable of 1400, 1500 barrels a day, but they're not allowed to do that.

In other words, they may -- If drainage were to occur, the person with the good well is the one being drained. And that's an important thing to understand here today, that correlative rights is not to make the wells equal, but correlative rights pertains to both parties.

Q. All right, Mr. Fant, let's go to Exhibit Number 15.

A. If I may, I have one other comment back on --

Q. -- 14?

A. -- Exhibit 14. Basically, this shows there are so many instances where there is no interference between the wells, that we absolutely need four wells per 160, we need that.

That was just the other thing. I apologize, Mr. Carr. I just wanted to say that.

Q. All right, looking at the number of wells that are needed on a 160, would you now go to Exhibit Number 15 and review for the Commission what this exhibit shows?

A. Okay, Exhibit Number 15 is two plots, and they -- both plots show basically the same thing. They are plots of oil rate versus cumulative production for a proration unit. The two proration units that we're looking at here in this particular -- in these two plots, are the southwest quarter of 29 and the northwest quarter of 29.

And you might ask, Mr. Fant, why did you choose those? Those are fully developed proration units, they are in the violation area, or the overproduction area. And furthermore they, up until this month, have not been curtailed, up until just -- we just recently started curtailing it.

And what I want to show you is, with these plots, we can calculate what the reserves for each well -- whether or not each well is contacting new reserves. There's been claims made by people that the four wells per 160 are just additional wells and just trying to get rate acceleration. There's been insinuations of that. And what I'm here to show you is that each well we drill develops brand-new reserves.

Now, looking at the first page of this, the southwest quarter of 29 -- I want to get my mental picture straight here on which wells -- where I was talking about.

The first well, what you can see is that over here on the left side of the X axis, you know, the first well was drilled, production jumps up and, you know, starts in, comes in, you know, stabilizes at about 400 barrels a day and starts on decline.

These wells in this area, as stated by Mr. Finley -- and I agree with him -- decline exponentially. So when you plot oil rate versus cumulative production, it should establish essentially a straight line. Well, and it pretty muchly did. And up until, oh, about a hundred and, oh, thirty, 120,000 or 130,000 barrels of oil production on this proration unit, that was the only well.

And you can take a -- you can run a line through those points, and you can see that it intersects the X axis at about 320,000 barrels of oil. Pretty good well. That's the ultimate potential recovery for that well.

So let's go in there. What happened after that? Once we had recovered about 130,000 barrels of oil, we drilled a second well, the Boyd Number 2. Suddenly, the production rate jumped to over 700 barrels a day, the next month it was under 700 barrels a day, and the well stabilized and began on decline.

And you can see that a line through that point -- At this point what we're doing is summing the two wells together. Okay. So this second line of data points includes not only the production from the first well but also the production from the second well. And you can run a line from that down to the X axis, and you can see that the two wells combined would recover about 550,000 barrels of oil, so we got an extra 210,000, 200,000-something barrels of oil.

We drilled the third well. It came in, and we -- you know, that bumped the ultimate production up some. And then we drilled the fourth well on the proration unit. And as you can see, the production, insofar as a daily rate in the fourth well, is significantly higher than any of the others had ever produced, a little bit better rock. And you can look at this one and see that, oh, the ultimate recovery is somewhere around 800,000 barrels for that proration unit.

But it's very important to note that if we had not drilled the last two wells, we would have stopped maybe just a little bit over 500,000 barrels of oil. So roughly 300,000 barrels of oil would have been left in the ground, not to be recovered by anybody else.

Now, if you look at the second page, it's the same type of plot. The first well -- And this is for the northwest quarter of 29. The first well is going to recover about 110,000 barrels of oil. The second well, very good well -- Now, the second well in this instance is much better than the first well. The second well boosts the recovery for the proration unit to about 500,000 barrels, kind of like the first one.

But the third well on this proration unit boosts it to well over 800,000 recoverable for the unit. And the fourth well moves it up to about 1.1 million barrels of oil recoverable for this proration unit.

Again, if we had not drilled the second and third well on this proration unit, if we had ascribed to only needing two wells per proration unit, on this proration unit we would have left 540,000 barrels of oil in the ground, not to be recovered.

Now, you look at two of them combined, 540,000 from one, roughly 300,000 to the other. Eight hundred -- Over 800,000 barrels of oil would have been left in the ground, if we had ascribed to only needing two wells per proration unit. And what this says is, most of those -- not most, but those reserves, that increment between them, are unique reserves to that well.

Q. Can you set a value on that production?

A. Well, let's just -- You know, if we have about 800,000 barrels of oil, these wells roughly produce around a two-to-one MCF per barrel of oil. Those additional wells, on these two proration units, just these two proration units, those four additional wells, is oil and gas worth about $19 million, of which $1.7 million would be paid in production taxes over the life of the well, that would not be recovered if we were not drilling four wells per spacing the unit.

Q. Now, Mr. Fant, what conclusions have you reached concerning the appropriate well spacing for the North and South Dagger Draw field?

A. We need four wells per 160.

Q. Let's go to Exhibit 16. Would you identify this, please?

A. Okay, Exhibit 16 is a plot with -- It has two Y axes on it. The right-hand Y axis is fieldwide production values in barrels or MCF per day, and the left-hand axis is pressures, pressure values, p.s.i. And it covers basically the life of the reservoir from 1971, when first production began in Dagger Draw, up through the end of 1995. That's basically -- And some of the pressure points run into 1996, but the production data, that's the -- the end of 1995 is the last point for which I had complete production data for all producers in North Dagger Draw. This deals specifically with North Dagger Draw.

Now, the black dots are pressure values as measured in wells at the time the well is completed. And what you'll see is that over in the early Seventies, 3000, 2950, 3050 was a common pressure encountered in the reservoir. In fact, I think Conoco has testified previously that, you know, about 3000 p.s.i. is what they call virgin pressure in the reservoir. I would like for you to note, however, that in 1976 there were pressures as low as 2200, 2300 p.s.i. measured in Dagger Draw.

Now, on this plot you can see, as I mentioned before, there was a ramp-up of production in 1990 through 1992 to a peak. It declined through 1994. Near the end of 1994 and up through 1995 there was another increase in production.

Now, we at Yates Petroleum did not drill many wells prior to 1989, and in fact there were not many wells drilled in this pool prior to then, you know, as evidenced by the production.

But if we draw a line, let's -- I want to draw -- you know, just draw a middle line there at 1989. Prior to 1989, we had removed 39 million barrels of reservoir fluid from North Dagger Draw. That's just from the production records. That includes oil, water and gas.

Now, I believe, and the data suggests, that -- and Conoco stated, that the pressures at that point, up until 1989, had dropped to roughly 2000 -- you know, somewhere between 1700 and 2300 p.s.i. You know, we got some varying pressure points. But at that point in history, reservoir pressure throughout Dagger Draw had declined to approximately -- or throughout North Dagger Draw, had declined to approximately 2200 to -- I mean, 1700 to 2300 p.s.i.

Now, if Conoco's theory of this great pressure communication across the reservoir, continuing be true, and if the Examiner findings were true, then that pressure would have continued to decline as we pulled more and more and more and more reservoir fluid from this reservoir.

But the black dots are the DST pressures in the wells as we have drilled them. And if you'll look at that, if you look since 1989, those pressures essentially haven't changed. They're not one constant flat number. And I'm going to explain to you why that's happening. But they're basically staying the same numbers, they're staying within the same range, they're not continuing to fall.

And it's very, very important that since 1989 we have removed from this reservoir, the operators have, removed 196 million barrels of reservoir fluid. We have removed five times as much reservoir fluid in the last seven years as were removed in the first, oh, 18 years. Yet the pressure hasn't dropped any more.

Q. Okay, Mr. Fant, we had from the discovery of the pool to 1988 39 million barrels removed; is that what you testified?

A. Yes, sir.

Q. And that dropped the reservoir pressures from 800 to 1000 or so pounds; is that right?

A. Yes.

Q. Since that time you've had five times as much fluid removed from the reservoir?

A. Uh-huh.

Q. And what has happened to the pressure?

A. We're finding pressures the same as we found in 1989; they have not dropped further.

Q. Now, the Examiner found that there was good hydraulic pressure horizontally across the reservoir. How does that finding square with the information you've presented with this exhibit?

A. If there were still good hydraulic communication horizontally across this reservoir, the pressures would have continued to decline throughout the reservoir. But they didn't, so it doesn't square with that data.

Q. And why has the pressure, in your opinion, not continued to decline?

A. People have continuously stated that Dagger Draw has fractures within it and that -- You know, we assume that once fractures exist they're there, period.

But what we're finding through a lot of study on different -- on not just Dagger Draw but on different fronts, is that fractures close as the effective stress across them changes.

And the way effective stress across a fracture changes is by reducing the pressure in the fracture. In other words, when you deplete the pressure in the fracture, fractures can close.

We know there are fractures in Dagger Draw; that's been stated by people. We know that the pressure had dropped with the removal of the initial 39 million barrels of oil. But we know it hasn't dropped any more. The fracture -- Some of the fractures have closed, helping to create the compartmentalization of this reservoir.

The fractures were the conduit by which fluid could move through this reservoir. In fact, fluid water movement through this reservoir was a trapping mechanism for the reservoir, it's why the oil and gas are found where they are. They're not in the places you would normally expect them to be in this reservoir. And the closure of these fractures has changed that.

What that says is that as these fractures close -- What it says is, the original wells should have made extremely high volumes of water for every barrel of oil. The original producing water-oil ratio for Dagger Draw was approximately 13 to 1. The current producing water-oil ratio for Dagger Draw is 2 1/2 -- for North Dagger Draw is 2 1/2 to one.

We have -- And there's always been this statement for years that people have said, We had to get the water off the reservoir, we had to get the water off. And in fact, Mr. Finley said we had to get the water out of the fractures so that the matrix could contribute oil to the production. You close the fractures, you bleed the water out of the fractures, they close, and when they do that you get higher oil cuts. That's what we have.

Q. Is the concept of compartmentalization in this reservoir consistent with all the data that you have on the reservoir?

A. Yes, sir.

Q. Is compartmentalization of reservoirs an accepted engineering concept?

A. Yes, sir.

Q. Would you refer to what has been marked Yates Exhibit 17 and identify these documents, please?

A. Okay, Exhibit Number 17 is actually two SPE papers that I want to provide to illustrate to you that compartmentalization of reservoirs is not some, you know, grand, new thing that we just thought of. It's something that has been accepted for years.

The first SPE paper is SPE Number 24,356 by a consulting firm, and all of these gentlemen and if there were, ladies, who wrote it are SPE members, they're members of the Society of Petroleum Engineers.

This particular paper discusses well performance. It's called "Well Performance Evidence for Compartmented Geometry of Oil and Gas Reservoirs". It was written -- It was presented in 1992, so a lot of the work had to go on with this thing in 1991.

They state, The last two decades have witnessed increasing evidence for compartmented geometry in oil and gas reservoirs.

So they've been looking at it for 20 years at this point, and now we're looking at it as 25 years, which is basically since the beginning of Dagger Draw.

Now, I want to read to you the first line of the abstract: Well pressures in production histories and transient pressure tests evaluated by conventional well-testing techniques and simulation are shown to indicate compartmented reservoir geometry arising by depositional and diagenetic processes.

Now, Mr. May has already spoken to you that this reservoir has undergone significant diagenesis, so diagenesis can create compartmentation.

And the second line of the introduction, or the second sentence of the introduction is very important. It says, Abnormally high completion pressures and anomalous well tests are often attributed to reservoir heterogeneity, with compartmentation being a dominant characteristic.

People are making the statements that the 2200-p.s.i. reservoir pressures that we're seeing in these wells are anomalously low. And I'm here to tell you that when a well, as Conoco presented in 1991, that after three years of production, drains the reservoir pressure down to 1100 p.s.i. in its compartment, when we drill a well next to it and hit 2200 p.s.i., I'm here to tell you that's an anomalously high pressure.

The pressures are -- If the idea of all this perfect communication across the reservoir were accepted, these pressures that we get in the wells would be much, much lower. So the 2200 is anomalously high, in fact.

It also says that -- anomalous well tests. Well, the IPs and well tests that we get on these wells are anomalously high. If we had this good pressure communication, like they're talking about, like they try to convey, across this reservoir, the new wells would be no better than the old wells in terms of rate at that time.

But the new wells produce like the old wells did originally, and oftentimes they produce better than the old wells did originally. They're in different compartments.

This -- One of their first witnesses ten years ago -- I mean their first reference that they use in this paper, ten years ago, Exxon completing the evaluation of reserves additions from infill drilling, and they reference it as Barber, *et al.*

The second paper that I've presented for us is SPE Paper Number 11,023. It's about five pages back in this. And that is that paper that talks about -- by these people at Exxon who did this work in 198- -- I mean, this was presented basically in 1982, because it's copyrighted by the SPE in 1982, so the work had to have been done in 1981.

In this paper they specifically mention

Pennsylvanian carbonate reservoirs as having compartmentation. And I just, you know, remind you that this is North Dagger Draw and South Dagger Draw-Upper Pennsylvanian reservoir.

So I bring these before you just to illustrate to you that compartmentation is known to exist, it's known to exist in carbonates, through diagenetic processes, and it's not an uncommon occurrence in Pennsylvanian carbonates.

Q. Mr. Fant, what is Exhibit 18?

A. Exhibit 18 is another SPE paper, SPE Paper Number 26,437, "Control of Fracture Reservoir Permeability by Spatial and Temporal Variations in Stress Magnitude and Orientation". Okay.

This paper was written by several people. One of the primary authors, and the primary author, is Mr. Larry Teufel, who at the time was working for Sandia National Labs. He is currently the -- I believe it's the Langdon B. Taylor Chair of Petroleum Engineering at New Mexico Institute of Mining and Technology. He's one of the premier minds in the world on what happens to fractures as the stresses around them change. Rock mechanics is really one of his best fields.

And this is a very complex paper, and -- But probably the most important thing to get out of it is that fluid flow through fractures not only depends on how many fractures there are and how well they're connected but on the conductivity of that fracture.

And he states in here, and it's basically at the beginning of the second page, that fracture apertures close and conductivity decreases as the effective normal stress across the fracture increases. That happens. And it happens because you deplete the pressure in the fracture.

We've known for years that when you fracture-stimulate a deep well, that if you try to produce that well too hard and draw the pressure down in the fracture too fast, you can crush and reclose that fracture. That's all I'm talking about here.

And, you know, in fact, I have discussed Dagger Draw with Mr. Teufel, and he -- You know, in trying to understand this fracture theory -- Mr. Teufel is one of the most brilliant people I've ever met, and discussing this with him is partially how I developed my premise of what's controlling the production in Dagger Draw.

These are some newer concepts. The change in the conductivity of fractures as we change the pressures in the reservoir, but they're no less valid.

Q. Mr. Fant, you're saying that compartmentalization of reservoirs is a recognized, from an engineering point of view, occurrence in oil and gas reservoirs?

A. Yes, sir.

Q. Let's go to what has been marked as Yates Exhibit 19. Would you identify this, please?

A. Okay, Exhibit 19 is a plot of the -- of oil rate versus time for the Savannah State Number 1. This is one of Conoco's wells. It's this well right here, in the northeast-northeast of Section 32, 19 South, 25 East.

It's one of the wells that Conoco has expressed a concern that they're being drained by the offset wells. They expressed it at the Examiner hearing, they have expressed it in the opening remarks thus far today.

Q. Now, what have you plotted, Mr. Fant, on this exhibit?

A. Basically I've plotted -- There's dots on this, which shows the actual rate in monthly production rates for the well, versus time. And then there is a solid line which is a rudimentary simulation of this well.

What I was concerned with is, how much acreage is the Savannah State Number 1 really draining? Can I calculate that?

I believe strongly that we have a compartmented reservoir. So take the statement that we assume that this is a compartmented reservoir. We want to know how large that compartment is.

I used equations from a textbook, Craft and Hawkins, which is an accepted reservoir-engineering textbook, and I used a technique called the superposition principle to place this well into an effective compartment and to analyze the -- you know, how this thing was put together.

Now, you have to make a few assumptions. But the assumptions I used were that the thickness was approximately 35 feet, the porosity was 7 percent, the permeability was about 14 millidarcies, a viscosity of 1 for the fluid, a reservoir compressibility of 2 times 10^{-4} per p.s.i. These are strange numbers, but these are the number I -- they don't mean a lot, but they're the numbers that go into the equations. They are the proper values for using in this type of situation.

And then the other big question is, how big is the area? What I had to do was adjust the parameters until I could create a match between the actual production and the predicted production in the well. And if you notice, that -- You know, I honestly feel like I did a pretty good job of matching them. See, we had the black line. It pretty well -- You know, the last two data points are a little off, but I think it did a very, very solid job of predicting the performance of the well, or matching the performance of the well.

It took me about a week to do this. This was not an easy set of calculations. That's one of the reasons it's not presented on every well in Dagger Draw.

But one of the most important things that this shows is that the compartment that this Savannah State Number 1 is in is about 29 acres in size, 29 whole acres. Now, if you take a 29-acre area and you call it a circle, it has a radius of 634 feet.

Now, when you look at the map, Mr. May -- you know, they had presented to -- or in the Examiner hearing, that -- they were worried that the Savannah State Number 1 was being drained by the State K Number 3. Well, the State K Number 3 is almost three-quarters of a mile away. You know, about somewhere -- you know, 3600, 3700 feet away. And the drainage -- The compartment that this well is in is 630-plus feet in radius. Okay, so it can't be that one.

The next closest well -- or the closest well, actually, is the Boyd -- closest Yates well is the Boyd 6. That well is 1900 feet away. Can't be doing it.

The State B Number 2 of Mewbourne, don't believe it was around then, don't think it could have been draining it. It was not creating this drainage. Even if it was -- I mean, even if it were around, again, it's too far away to be creating this drainage.

This well is in its own compartment. It's draining it very rapidly because it's a small compartment. And there's not much that we as an offset operator can do about the fact that Conoco has a small compartment that their well is in.

Q. Mr. Fant, what does this tell you about the number of wells you ought to put on a 160-acre spacing unit?

A. Well, I need at least four per 160, that's basically what it says.

Q. Let's go to Exhibit Number 20. Could you identify that, please?

A. Exhibit Number 20, okay. This is a plot of the production of the State K Number 3. This is oil production in MCF per day throughout time, up through February of 1996. I didn't update it. This is the exact same plot I showed in the Examiner hearing.

Now, the well at the beginning of this year was producing in excess of 1000 barrels a day, and it basically had that capability until we had to restrict it.

Remember, this is -- The State K Number 3 is in the southwest quarter of 28. It's the only well on the spacing unit. It's the only well on that spacing unit. We have not drilled any other wells on that spacing unit. That well is capable of 1000 barrels a day.

The data has already shown strongly that there is compartmentation of this reservoir and that we do need four wells per 160. Well, we drill four wells on this 160-acre spacing unit of this caliber, and you've got 4000 barrels a day of productive capability in the wells. That's where the 4000-barrel-a-day request came from. It's not based upon grabbing some number out of the air; it's based upon the data of this reservoir. This is a very good well, I admit that.

Q. And what you're doing is asking for an allowable limit that will let you fully develop this tract and, if you get four wells of this nature, not have to restrict them?

A. Absolutely.

Q. And you have made a recommendation for South Dagger Draw that is very simply twice the rate you're seeking in North Dagger Draw; is that right?

A. Yes, sir.

Q. And you're doing that just to try and maintain some sort of compatibility between the two reservoirs?

A. That's been the historical focus between -- One of the historical focuses is to try to maintain the two incompatibilities with each other, and so that's why we brought that.

Q. And even though your data shows that the efficient and effective and prudent way to develop 160 acres is with four wells, can you do that if you don't have the allowable that will let you produce that?

A. No. I mean, we can't drill any other wells on this proration unit. One well is already -- I mean, we've been accused of going out there and drilling too many wells. This is one well on a proration unit.

Q. And if there was interference or communication in drainage between wells, what happens with a -- say a 1000-barrel-a-day allowable on this well, in terms of drainage from offsets?

A. I guess I'm not really following you.

Q. If you have one well and you need three --

A. Oh, okay.

Q. -- or need four on a 160-acre tract, what happens in terms of drainage?

A. Well, we -- if drainage were to occur, we're really exposed to drainage. We don't create it, we get drained. Because we would not -- we're not allowed to drill any offset wells.

Oh, yeah, we could go out and drill them. Then we would have to shut this well in, and I'll show you what happens to a well when you shut it in, I'll show you that.

Q. Mr. Fant, we're not talking about just one unique well, the State K Number 3, are we?

A. Well, I mean, that's the way it has been portrayed by some people. But no, we've had -- You know, just to give you two quick statements, you know, the

Diamond, I've already presented that that well had a capability of 1300 barrels a day. We've already shown that.

The Patrick Number 4 and the Polo Number 6, these wells were both completed August 1st of this year. Different spacing units.

The Patrick Number 4, the initial production on that well was 2467 barrels a day. That's a big well. In fact, to my knowledge that's the highest initial potential in the history of Dagger Draw, and I -- you know, I will say that is high.

The same day we completed the Polo Number 6, and its initial potential was 1790 barrels of oil per day. So it's easily seen that, yes, 4000 barrels a day is needed when you have wells of this capability.

Q. Now, to get wells back in line with our current allowables, is it possible for you to shut them in at regular intervals and produce them at high rates when you actually have them on?

A. Okay, these wells are currently -- since we -- Back in the Examiner hearing and in the April meeting with Mr. Gum, we agreed to restrict our wells, our proration unit production to 700 barrels a day.

And to do that, we place the wells on time clocks, just a simple mechanical clock, electric clock, on the unit that turns the pump off for a period of time and then turns it back on. And it was on basically -- It ran so many hours a day, then it was off the rest of the hours of the day.

Now, I was -- At the time of the original hearing, I was wondering, you know, when we're producing, then, while the pump's turned on we're producing at maximum rate, and while the pump's turned off we're essentially not producing at all.

And so there was -- people were proposing, well, then, that's going to -- you're going to get your high oil cuts, then, if you do that.

And so I did some calculations to show that cyclic production of the well, cycling the production of the well, turning it off, on, off, on, was essentially no different than producing it constantly at a reduced rate, after a period of time.

You would get short-term benefits, a few days, a couple of weeks. But over time the effects would be the same as just producing it at the lower rate.

And in fact, I did some -- I presented two plots -- it's Exhibit --

Q. Exhibit 21.

A. Exhibit 21, yes, sir. -- that compare cyclic production versus continuous production at the reduced rate.

Now, these are kind of tough to understand, but what we have on the Y axis, cyclic production drawdown as a percentage of continuous production drawdown. If you put your well on -- And the X axis is time.

If you turn your well on -- let's say we just -- Your well -- you want to produce it at 1000 barrels of fluid a day, and you have to restrict it to 500 barrels of fluid a day. Now, if you just put a pump in there that can produce 500 barrels of fluid a day, that's the benchmark, that's what I call the benchmark in this. That would be a straight line at 100 percent, right through the middle of it.

And what this shows is that -- the other thing we can do is, let's say we turn it on for 24 hours and then we turn it off for 24 hours. So when we turn it on for 24 hours, let's say we have a pump in there capable of 1000 barrels in 24 hours. We produce it at that high rate for 24 hours, and it's like -- and that's producing at the high rate. You know, it's twice -- You have 200 percent the drawdown that you would have had otherwise.

There are three curves on this thing, and they represent the effects at different depths in the reservoir, 50 feet, 100 feet and 150 feet into the reservoir. These calculations were done with the same superposition principle and exponential integral solution out of Craft and Hawkins that I used in my Savannah analysis.

But what this shows -- What you can see is, you know, if you look at 150 feet in the reservoir, out here at eight or nine or ten days, yeah, there's still some benefits of doing the cyclic production, but it's almost down to just the 100-percent line, which is saying that it's basically the same as producing it at a 500-barrel-a-day rate. And this thing is kind of -- you know, it -- whether it's 1400 and 700, or 1000 and 500, it works on the same types of scale.

The second page is what the comparison looks like when you use a 12-hour cycle, and it just says -- and if you look at the long dash, 150 feet in the reservoir, it says after about nine or ten days, there's really no difference between what goes on between producing at the reduced rate or producing in a cyclic manner. It says -- it's -- What it really says is that the effects of restricting the well would take time to manifest themselves.

Q. Okay, let's go to Exhibit 22. What is this?

A. Okay, Exhibit 22, if you'll remember, I said that we would reduce the -- when -- We told the Commission that we would restrict the production from the overproduced units to the 700-barrel-a-day limit. That was done back in

April.

At the time we met with Mr. Gum in April, I presented some calculations to him that what I felt would happen was that the oil cut in these wells would move from, you know, 59 to 60 percent, down to about 52 percent. Okay? That was based on all the information in the first few exhibits I gave you about the oil cuts, slopes and all those kinds of things.

And I was kind of -- You know, we restricted them, and it started to take time for these things to drop. They didn't drop immediately. In fact, you know, they fluctuated for a few days, they went up. But they were fluctuating. This is daily oil cut versus time, for those restricted proration units.

Now, it took about two months for the oil cut to stabilize in these wells with this cyclic production method we were using. But the oil cut stabilized -- You know, the mathematical number is, I think, 51.6 percent. Yeah, this black line through it is basically stabilizing at 51.6 percent. But that's 52 percent to me. I mean, they did exactly what we represented that they would do. This shows that the oil cuts are sensitive to rate.

Q. Mr. Fant, if production rates increase, will these oil cuts improve?

A. Not immediately. This is -- It took time for it to come down, because we had -- You know, basically we had to damage the reservoir back to some distance. And in doing so, having to restrict the wells has harmed -- has hurt the reservoir, and it will take time for that to come back. It should -- When they're brought back to full production it should -- You know, based upon this data is, it will take about two months to get them back to where they were.

Q. And after they come back up, are you ultimately going to be able to recover the same volume of oil, or will some of it have been lost?

A. No, we won't. We will have pulled excess water out of the reservoir, which is reservoir energy. We will have pulled additional pressure from these compartments in the form of water.

When that water comes out, something has to expand to take its place, and so that water has come out, and that -- and we will not be able to recover some oil in the future.

Q. Are you saying that you will recover the same volume of fluid but less of that fluid will be oil?

A. That's basically the way it has to be looked at, and that is what is going to happen.

Q. Let's go to Exhibit 23. Can you identify and review this, please?

A. Okay, Exhibit 23. Back in July Mr. Collins asked me to -- Brian Collins, this is our assistant operations manager -- asked me to write him a letter and let him know what has been lost, what damage has been done because of restrictions. This particular memo talks about what happened between the date we restricted the wells in April 12th and this July 12th date.

And basically what it shows, there's three pages of memo, and then there's a set of calculations there in Attachment 1 to this, that show my original calculations in April of 1996. The next-to-the-last line in this table says that we would -- it's called Water-Based Loss -- would be roughly 21,000 stock tank barrels of oil. Okay, that's based upon what I predicted would happen to the oil cut. And it says basically that represents 7 percent of the restricted production over that time period is lost.

Then there's another graph similar to the data I just presented, only up through the July 12th date.

And then the last page is another lost-oil calculation. And if you'll read at the bottom it says, Calculation Based upon Actual Data. It's Attachment Number 3, and it says we've lost 21,078 stock tank barrels and roughly 7 percent, which is 7 percent of the restricted production.

Basically what's happening here is, if we restrict a well, basically 7 percent of that restriction is being lost permanently. I mean, that water that's being pulled out now is fluid we won't pull out in the future, and so that hurts us.

Q. Is that the same approach you were using in estimating the volume of oil permanently lost in the 104 days between the hearing and the Order?

A. Yes, sir.

Q. Could this production be produced during secondary recovery operations?

A. Well, no, I don't believe so. I believe it's permanently lost at this point.

Q. Why is that?

A. Primarily because secondary recovery is basically attributed to waterflooding. We have a fracture system, which, basically, we believe we do. We believe it's closed now. We believe that the pressure reduction has closed that fracture.

But if we go in there and inject water, our fracture system is going to open back up and the water is going to run right through it, and it would basically indicate that a waterflood probably wouldn't work, I mean based upon that theory.

You know, that's my belief right now. I think there may be some ways, you know, we can work on that.

But...

Right now we have a pilot project in South Dagger Draw, right down here, the Sawbuck Pilot Waterflood, and the results have been disappointing.

But again, this supports the model that I'm presenting to you of how and why this reservoir produces the way it does. It's fitting all the data, and it's very important that all the data fits with the model. If it doesn't, the you've got to throw the model out.

Q. Mr. Fant, this question was raised back during the May hearing and it is, Can't you just shut these wells in until they get back in balance?

A. I was asked that question in May, and there was kind of two prongs to it. You know, basically it was, will you suffer drainage if you do? And basically I don't believe -- not on any magnitude of anything.

The danger with shutting them in is that you may never -- There's a risk of losing that well. It may never -- It may not produce when you try to turn it back on.

Q. Let's go to Yates Exhibit 24. Would you review that now?

A. Exhibit 24 is a production -- daily production plot on the Polo "AOP" Number 6. This is one of the wells that I just recently commented to you that it had a very high initial potential. And I sometimes get a little animated about this stuff, but this clearly to me will illustrate to you the dangers of shutting in wells in Dagger Draw.

We're really not in the habit of shutting in high -- good, productive wells for long periods of time. But in light of what's been going on in this process, we ended up shutting in this well in mid-August. It came on first of August, and you know, the first day was a partial day. But, you know, as you can see, the green is the oil production, the red is the gas, and the blue is the water. And the black diamonds are the oil cut.

See, the well came in at 1700, 1800 barrels a day. It fell down and stabilized, about 1300 barrels of oil a day. It was stabilizing in mid-August. The oil cut was stabilizing at about 40 percent, and the water was about 2000 barrels a day.

At this point, this well had basically produced its allowable for the month, so we turned off the pump, shut the well in. Or we basically turned off the pump.

And in September we went out and I believe it was about the 4th of September, 3rd or 4th of September, turned the well back on. Now when this well was shut in it was a 1300-barrel-of-oil-per-day well with a 40-percent oil cut. We turned it on. All we had done to this well was, we turned the pump off. And a couple -- You know, a little over two weeks later we turned the pump on. Came back and it was, oh, 600-and-some-barrel-a-day, dropped down below 600, it increased to just over 700 barrels a day. But I'm also here to tell you that the next day it dropped back below 700 barrels a day.

So we took a nice 1300-barrel-a-day oil well and because we had to shut it in to comply with OCD regulations, the rules that were in place, the well was damaged to about half of its productive capability. The oil cut went from 40 percent to basically 20 percent. To me, that's -- this is horrible waste.

Q. Mr. Fant, there's another thing I'd like to address with this exhibit. Earlier, when we were talking from Exhibit 10 --

A. Uh-huh.

Q. -- we were talking about the slope of the oil cuts --

A. Uh-huh.

Q. -- how you had mathematically calculated those --

A. Uh-huh.

Q. -- and you talked about there being some statistical aberrations or something. Does this show you what you were talking about when you said one of those statistical aberrations?

A. Yes, if you look in the middle portion, while the well was turned off, this particular well flowed some oil to the surface. The gas was able to lift some oil. And if you'll look at the oil cut -- It's below the 100-barrel-a-day line; it's down around 20 or 30 barrels a day. If you'll look at the oil cut, it was 100 percent. And you might think, well, you know, this well -- if we really slowed down the production from this well we would get 100-percent oil.

But that's not the case. We know -- it's -- Everybody since day one with this reservoir has stated, nothing enters -- no fluids enter -- all -- no zones in this reservoir produce only oil and gas; they all produce water.

So the question becomes, what's happening to the water. What's happening to the water in this well?

What's happening is, we're getting natural fluid separation in the wellbore. The fluid comes into the wellbore, the water goes to the bottom, the oil and gas go to the top, and because the oil is on the top and the gas is bubbling up through it, when it flows a little bit to the surface -- It's not a pure flowing. It kind of, you know, it slugs a little bit to the surface. It's always oil and gas that come to the surface. But something has to be happening to that water.

This well has multiple little stringers in it. Those stringers are not going to be at the same pressure. They can't be. Mr. May has already illustrated that we have vertical segregation in this reservoir.

Furthermore, when you start to produce any reservoir, vertically segregated stringers, except by some freak of nature, will not deplete at the same rate. So the pressures are going to be different in those. One's higher pressure, and all the rest are lower than the highest pressure.

So what happens is, the water gets pumped, essentially pumped, into the lower-pressure stringers by the higher-pressured stringer. The higher-pressured stringer is allowed to flow water, gas and oil into the wellbore. It separates -- The pressure in there is high enough to pump the water into the others and allow some of the oil to flow to the surface.

That's part of the damage mechanism for this well. That's part of the reason it got damaged. That's how it happened. We know that no zones in Dagger Draw produce 100-percent oil and gas, that don't produce water. So the water had to go somewhere, and there's no other place for it to go but back into one of the stringers. And this well was damaged.

Q. Now, Mr. Fant, when you were running your mathematical calculation, trying to predict the slope --

A. Uh-huh.

Q. -- of the oil cut, if you had a well like this and it had been shut in for a period of time, did you throw out some of the points, or did you just include every single point on this graph?

A. I don't throw out mathematical points. I mean, I'm going to -- if I present a statistical technique, I'm going to use all the data.

Q. And in this case, if you had used all the data, what effect would that have had on your calculated slope of the oil cut?

A. This well, it would show an extreme negative slope if I did that calculation on this well right now, because of that erroneous data when the well was shut -- when the well was turned off. That's not proper data, that's not data that can be utilized in that.

Q. And so --

A. I did the calculation for 280 wells, and I was not going to go in and try to weed out any data. I don't want to be -- because that looks -- That doesn't look right. I used all the data.

And so basically -- There are a few of those negative-slope wells that are within the overproduced area. Those are the kind of wells that when their pumps fail, they can throw a little bit of oil to the surface, which gives you a low rate of oil with a high oil cut, which gives you -- which is an outlier data point, which gives you a statistical aberration to the method.

Q. And in preparing Exhibit 10, you used all the data available to you in the wells?

A. Yes, I used all data. I didn't cut any out.

Q. Okay, let's go to Exhibit 25. Will you identify this, please?

A. Exhibit 25 is a sheet of paper that has some calculations on it that show the revenue lost in the next 18 months if the Examiner order is implemented.

The top portion of the paper shows -- is entitled "Cost of Delayed and Lost Production", and it references the July 12, 1996, memo to Brian Collins.

It shows that New Mexico Revenue in 1996 will be reduced by $1.1 million due to the restriction of approximately 3325 barrels of oil per day for 92 days. That's a loss -- That's what the State of New Mexico lost because of that restricted production.

The memo further -- And so what we can do is, we can take $1.109 million, divide by 3325 barrels of oil per day and 92 days, and we can get a cost per day, per barrel of oil per day, shut in or restricted, and that's $3.62.

The memo further states that, 93 percent of the revenue is delayed and 7 percent is permanently lost. So that breaks drown to $3.37 cents per barrel of oil per day, times days delayed, and the permanent loss is 25 cents, with the same units.

The second portion of the calculations talk about the amount of delayed production. The total production for the field is in excess of 1 million barrels, all operators. Now, the Examiner order says we need to make this up in 18 months. That would require an average restriction of 1827 barrels of oil per day. That's simply a million barrels divided by 547 days, which is 18 months.

The thing to note is, this value does not represent the total restriction on the field, because there are at least four other proration units that are capable of producing in excess of 700 barrels of oil per day with the existing wells. I'm just talking about existing wells, not anything that could newly be drilled. I conservatively estimate that at least another 1000 barrels of oil per day would be restricted, and I'm here to say that's an extremely conservative restriction. This brings the total restriction for the 18 months to be about 2828 barrels of oil per day.

Now, the revenue-impact over the next 18 months.

Delayed revenue, 547 days, 28 barrels of oil per day, times the $3.37 comes out to $5.2 million.

The lost revenue works through the same calculations and comes out to $387,000.

Now, we've already delayed some -- some already. The revenue already delayed is -- we've done it for, you know, roughly 153 days, when I made this memo -- $1.7 million, and we've already lost $129,000.

This is lost revenue to the State of New Mexico. This is not what has been lost to Yates Petroleum or the other operators or just some individual royalty owner. This is what's lost to the State of New Mexico.

That totals up over the next 18 months, if the Examiner Order is implemented, $7.4 million that over the next 18 months the State of New Mexico will not have.

Q. Mr. Fant, in your opinion is it necessary to require the makeup of this overproduction to protect the correlative rights of operators in this field?

A. No we don't need that. In fact, the only potential impact of requiring this to be made up -- and I'm speaking from a technical sense here -- the only impact of -- potential impact of making us do that -- Actually, there's two. One is damage to wells, but the other impact is to impair the correlative rights of the overproduced units.

Q. What would -- We've set out here in this exhibit the amount of delayed and lost revenue to the State. You said it didn't also show what would occur to Yates. This would occur with the same effect on other working interest owners in the pool to varying degrees; is that not right?

A. Yes.

Q. It would also impact other royalty owners; is that not right?

A. Yes.

Q. And you included only the existing wells in your estimate?

A. Yes.

Q. If you drill additional wells that come in as recent wells have, that would even further exacerbate this number, would it not?

A. Yes.

Q. What conclusions have you reached from your engineering work on this reservoir?

A. That the higher producing rates in the reservoir result in higher oil cuts, lower GORs. Those situations prevent waste. That's probably the biggest thing. They prevent waste because for every barrel of oil we're pulling out of the reservoir, we're pulling out less gas and less water.

And that's an important thing to do. It's an accepted principle in petroleum engineering that pulling out excess reservoir energy reduces the ultimate recovery of the field.

Q. To make up the overproduction, what would you have to do?

A. Just operationally, we'd have to shut the wells in, and we've seen what that will do to wells.

Q. The cancellation of the overproduction in these pools impairs the correlative rights. I want you to summarize that answer.

A. Could cancellation of overproduction --

Q. -- impair correlative rights?

A. No, just as I said, or not canceling it can impair correlative rights.

Q. Even as operator of a better well, you have a right to produce what's under your tract; is that --

A. That's right, correlative rights doesn't make all wells equal.

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, it would.

Q. Were Exhibits 7 through 25 prepared by you?

A. Yes.

MR. CARR: May it please the Commission, I would move the admission into evidence of Yates Petroleum

Corporation Exhibits 7 through 25.

CHAIRMAN LEMAY: Without objection, those exhibits will be entered into the record.

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

CHAIRMAN LEMAY: Thank you.

Let's take a little break and then come back for cross, about ten minutes.

(Thereupon, a recess was taken at 2:20 p.m.)

(The following proceedings had at 2:19 p.m.)

CHAIRMAN LEMAY: Okay, we shall continue. Is that the end of your direct, Mr. Carr?

MR. CARR: Yes, sir, Mr. Chairman.

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Fant, let me reconcile two statements that you made towards the end of your presentation.

Am I clear in understanding that should the Commission require Yates to shut in those wells that are in overproduced spacing units, that you have no concern or reservation about those spacing units than being subject to drainage during the period of that shut-in?

A. As I've stated in my case, in the Examiner hearing, I don't believe that's a big consideration. There -- As has been pointed out, that there are some small instances of interference between wells in the overproduction area. But in my opinion, it's not a significant concern, no.

Q. All right. If drainage was to occur, the problem in this reservoir would be that there is simply a limited amount of energy by which to produce the fluids, and if there is offsetting drainage, then there would be pressure depletion by certain wells while others are shut in, right?

A. If there were drainage, if that word is a consideration --

Q. Yes.

A. -- in that particular stringer, then, there conceivably could be.

Q. All right. If under your position there would be no drainage occurring, Yates' wells could be shut in, then something else is causing your example, the Polo well, after being shut in, not to return to the level of high oil cut that it had enjoyed before it was shut in? Yes?

A. I'm not understanding the question.

Q. All right. You said you're not concerned about drainage. You were concerned about shutting in the well, and there would be some kind of near-wellbore damage occurring, or something to that particular individual well that precludes it from coming back and producing at the oil cuts prior to the shut-in?

A. Yes, there's wellbore damage.

Q. All right. Your conclusion, then, based upon the Polo Number 6 well, is, after that shut-in period it did not come back at the higher oil cut it had enjoyed previously, and therefore it wasn't subject to drainage; there was something else that affected the well?

A. I didn't quote anything about that well with regards to drainage.

Q. I understand that. It was your example of a well that was shut in and then attempted to be restored to production later, and it did not return to the same level of productivity, right?

A. Yes.

Q. And you attributed that difference to the fact that the well must have been damaged somehow by the shut-in?

A. Yes.

Q. All right. The example you gave us was the Polo Number 6, and if we'll use your Exhibit 1 as a locator map, it's up in the northern portion of North Dagger Draw, it's in Section 10. And if my map is correct, it appears to be in the southeast quarter of 10, and it would be the southwest-southeast of 10, I believe that is the Polo

Number 6. Did I find the right well?

A. (No response)

Q. Yes, sir, did I find the right well?

A. Yes.

Q. All right. Your Exhibit 24, then, shows the data points in August, and then it was shut in. Help me read this schedule here. Approximately how long a period was it shut in?

A. A little over two weeks.

Q. Okay. And then in early September it is returned to production; it's at a lower rate?

A. Yes.

Q. All right. When we look at the compartment that that well is producing in, do you have an opinion as to whether it is in the same compartment with the Polo wells in the southwest of 10? There's some other Polo wells there.

A. At this point in time, there is not enough data to make that -- any estimation of whether or not it is in that same compartment.

Q. During this period of time for shut-in on the Number 6 well, were the Polo 1 and/or 4 being produced?

A. The Polo 4 was. I do not know about the Polo 1.

Q. The direct west offset to the Number 6 is being produced?

A. Yes.

Q. Do we have enough data available to determine whether the Number 6 well has been affected by the continuing production from the Number 4 well?

A. No.

Q. Let me look at Exhibit Number 1 with you. Again, within this area of overproduction, rule violation, do you have a calculation or a total, Mr. Fant, of what is the total volume of overproduction attributed to the Yates spacing units?

A. Are you speaking of Exhibit 1 or --

Q. I'm sorry.

A. -- Exhibit -- whatever number -- 7?

A. I have confused you. I'm looking at Exhibit 7 --

A. Okay.

Q. -- and I've been calling it Exhibit 1.

Let's look at Exhibit 7. Within this area, then, do you have a total cumulative overproduction for the Yates-operated spacing units in North Dagger Draw?

A. As of what time?

Q. As of today.

A. As of today, the current -- I do not have an exact number. It's approximately 950,000 barrels right now.

Q. Okay.

A. It's lower than what it used to be. It's going down.

Q. And part of that reduction is the fact that you have gone ahead, or Yates has gone ahead and restricted its capacity on those spacing units, and you are beginning to accrue some over- -- underproduction, if you will, or some credit to apply against the overproduction?

A. Are you speaking of the 350-barrel-a-day restriction?

A. Yes, yeah.

A. The number I quoted you was as of the end of August, which was prior to that -- us implementing that restriction. We implemented that restriction basically last week.

Q. All right.

A. So that -- The reduction to 950,000 occurred prior to that.

Q. All right. But for the sake of discussion, we'll use a number, 900,000 barrels, subject to check, whatever the exact number is.

I've glanced at these two SPE papers. They're Exhibits 17 and 18. They appear to be dated and available. You'll have to help me; perhaps your eyes are better than mine. Exhibit 18 appears to say it was released at a symposium in October -- Is that 1992?

A. You are speaking of 17?

Q. 18, sir.

A. 18 was released 1993.

Q. That's a 1993 number?

A. Uh-huh.

Q. Okay. And when we look at Exhibit 17 -- There's an earlier paper, I think, in one of these, but this one on top says 1992?

A. Yes, it's 1992.

Q. All right. I've scanned through both of these papers, and I can't find anything to do with rate. They don't talk about how fast to produce these.

A. I don't know --

Q. Yeah. These papers don't deal with rate. They deal with the notion of the compartmentalization of a Pennsylvanian-type reservoir, and they speak to the probability of drilling wells in a density that's compatible with what's happened in North Dagger Draw, you know, the 40-acre well density; isn't that what we're talking about here?

A. Yes.

Q. All right. This information was available to you in the summer of 1995, wasn't it? These SPE papers?

A. Yes.

Q. Except for some of the later displays, most of these were presented to the Examiner in the May, 1996, hearing, right?

A. Uh-huh.

Q. The proposition that the reservoir is compartmentalized and the opportunity to produce these wells at greater than the existing allowable of 700 barrels a day was known to you in the summer of 1995, was it not, sir?

A. I believed in 1995 that compartmentalization existed in North Dagger Draw.

Q. Okay. And by May of 1995, Yates has wells in these violation spacing units that had the capacity to overproduce the spacing unit allowable; is that not true?

A. Yes.

Q. All right. So in May of 1995, you had that knowledge.

In addition, you knew the reservoir may be compartmentalized, right?

A. I believed it at the time, yes.

Q. All right. Let's look at Exhibit 7. When I look at the map, it appears to me that Yates controls and operates the east half of 19, all of 20, all of 21, all of 28, all of 29.

Mr. Fant, what precluded you in the summer of last year, prior to overproducing these wells, from filing a case at the Oil Conservation Division, bringing in this information to the Division, with notice to the industry, and develop a pilot project within the area you control, and test these concepts?

A. I would say, really, probably nothing, other than the fact that in May they already thought I was premature, or they thought in May of this year that I was premature, so last year would have been -- as I stated in the Examiner hearing, that nobody would have believed me from the year before.

Q. Well, you made that conclusion, but who was skeptical of your argument?

A. If people were skeptical in May of this year, then they certainly would have been skeptical in the summer of last year.

Q. You had the ability to file such a case in the summer of 1995 and present this argument then?

A. Yeah, it could have been filed.

Q. And prior to achieving the magnitude of overproduction, then, had the opportunity to get the Division Examiner to approve the overproduction, even over opposition?

A. You know, that -- that possibly could have been thought of. But so much of the data that has been presented here to confirm this was not -- all of this data was not available at that time.

Q. And that would be the point of a pilot project within the area of your control. You come forward with your hypothesis, you get approval to test the concept, we develop a procedure that does it without violating correlative rights, and you come back a year later and demonstrate that it worked?

A. Now, that's an interesting point. You say it doesn't violate correlative rights. Well, Conoco has said that doing this does violate correlative rights. We did not have a constant interest throughout this area. We believe that it does not violate correlative rights.

But what you just proposed can't happen, because yes, we may be the operator, but that does not mean that we have the same interests throughout, and it does not mean that we have the same ownership of other parties throughout.

So what you just proposed is really not possible because of the variety of ownership in the area.

Q. Did you even try to contact the other operators and interest owners in the summer of 1995 and ask them whether they would support you in such a project?

A. No, sir, I did not. We knew that it would not be possible at the time.

Q. If you'll turn with me to Exhibit Number 23, this

is your memo to Mr. Collins about trying to put a value on what you characterize to be the lost oil?
A. Yes.
Q. Can you estimate for us, Mr. Fant, what is the value of the oil gained as a result of overproducing the allowable?
A. Well, the value of it is the -- basically 7 percent -- the value of what's gained is equal to the value of what's lost if we restrict the wells. That's basically how it would work.
Q. That's --
A. So, you know, to New Mexico over the next -- you know, it's equivalent to what's lost here.
Q. All right. So if I take the 930,000 or 940,000 barrels of oil overproduced in the allowable and multiply it by your $20 oil price on page 2 of this display, then I at least come up with the gross dollars that are attributable to the overproduction?
A. Yes.
Q. Okay. Turn with me to Exhibit Number 22.
A. Would you help me in what 22 is?
Q. Twenty-two is the oil cut versus time on the restricted proration units.
A. Oh, okay, yes.
Q. The data points are plotted from April of 1996

through part of September of 1996.
A. Uh-huh.
Q. And what you're representing here are the changes in the oil cut over time as these wells within the violation area were curtailed?
A. Yes.
Q. Okay. The average magnitude of change, I think, is about seven or eight percent, between producing these at capacity and then producing them at the restricted rate?
A. Yes, sir.
Q. Okay. Is the reduction in oil production at the restriction due to any pressure depletion that's occurring in the reservoir?
A. Please ask that again. I didn't -- I'm not really understanding your question.
Q. The oil cut has been reduced at the restricted rate.
A. Uh-huh.
Q. What, if any, effect has pressure on that event?
A. Over this time period, minimally. You know, basically none.
Q. Okay. Describe for me what your argument is that demonstrates that the reduced wells at the restricted rates are in fact actually losing oil. What's your concept?
A. My concept is what I've stated before. You are

pulling out excess water for every barrel of oil.

So actually, over this period of time that we restricted these wells, the pressure dropped less in the reservoir -- you know, the pressure-drop in a couple of months in the reservoir is pretty small. But -- We pulled less total fluid out over this time period, out of these compartments, and so it dropped less than it would have if we had been producing at the higher rates.

But when we get to the end of the life of these wells, because they were restricted we will recover less oil, because more -- water has been taken out. And if we take water out now, then near the end of the life of the well that represents oil, water and gas that will not come out of the reservoir, because we've taken that volume out already as water.

And the oil represents about 26 percent of that final production stream, and so the 26 percent of the water volume we're taking out now is oil that won't be recovered at the end of the life of the well. That's how the math works on it.

Q. All right. Have you attempted to analyze this in another way to try to quantify the volume of ultimate oil recovered that is not in fact recovered? Have you attempted to do it with any production decline curves?

A. There is certainly not enough data in here over this time period to do that. But it is quite simply -- You take 7 percent of the overproduction and that, if required to be made up, that will be lost forever. And if you're looking at a million barrels fieldwide, that's 70,000 barrels of oil, just because we have to make that up. That doesn't include the restrictions, because the wells are actually capable of more than 700 barrels a day.

Q. Did you work with Mr. Collins on determining what method you would use for restricting or curtailing these wells?

A. I did the calculations, and what I showed Mr. Collins was that it did not matter whether you cycled the production or whether you simply ran smaller equipment to do it. The net effect was the same.

Q. Okay. In the field, then, did Mr. Collins require that all the wells be restricted at the same percentage, in order to achieve that spacing unit's maximum allowable of 700 a day?

A. No, no, they were simply -- Basically, the restrictions, in order not to burn up excessive equipment, if you're going to -- if you have three pumps, three sub pumps on a -- or two sub pumps on a spacing unit and you can achieve the results of obtaining 700 barrels a day by cycling one of those pumps and running the risk of burning it up, it's better to run the risk of only burning up one pump than two, than burning up two pumps.

So generally on those various units we have some lower-volume wells because they're older, and then we have generally a high-volume well, and that high-volume well is generally the one that was restricted.

Q. All right, that was my question.

The method you utilized, then, to get within the restriction was to curtail the high-capacity well?

A. Basically, yes.

Q. All right. Did you attempt to take a high-capacity well, as a field example, shut it in and then leave it shut in for an extended period of time, producing the allowable out of the older wells and then returning the newer high-capacity wells to production later to see what would happen?

A. No, basically we didn't do that for a couple of reasons.

First, shutting in a sub-pump well for an extended period of time is a danger- -- not a dangerous thing to do, but it's not a good practice, because when you shut them in for an extended period of time, the probability of them turning back on goes way down, because as the well's pressure builds up bottomhole, you can short out the equipment downhole. And if it shorts out, you've got -- you've just burned up -- You haven't bumped up the pump then, but you do have to get a pulling unit out there and trip the well.

So no, we did not do that because of operational constraints.

Q. Within the violation area, did you have the ability to shut in the older wells and produce the allowable out of the new well and still maintain the allowable restriction?

A. Someplace that -- Some places, that might have been conceivable, but I do not believe that would have been practical.

Q. What I'm looking --

A. You would have had the same problems. You shut them in and you run the risk of burning up pumps.

Q. What I'm looking at is, you have -- Yates has what? Got eleven, I believe, eleven spacing units that are overproduced.

A. Well, not at this time, no.

Q. Well, in the hearing -- All right, there's ten, I guess.

A. I believe it's actually nine.

Q. We'll take nine for the sake of argument.

Within those nine, we've got various combinations of spacing units, some of which have four wells, some have less?

A. Uh-huh.

Q. Did you try to create a field example to show us various options about how you might shut your wells in, in these various spacing units, to see whether you could achieve the 700-a-day maximum and yet not have an adverse effect on the wells?

A. Well, as the data I've shown shows, that you shut in a well and you can damage it. And so any kind of shut-in runs the risk of damaging the reservoir. So -- shut-in for a length -- for an extended period of time runs the risk of damaging the reservoir.

So no, we did not go through to run all these tests like you're saying. But we simply showed that, hey, when we said the oil -- we said the oil cuts would go to 52 percent, and that's what the oil cuts did.

Q. Other than the Polo 6 well, which is your example of what you say is a damaged well as a result of shut-in --

A. Uh-huh.

Q. -- do you have any other examples?

A. The production department, in history, had talked about the same type of occurrence in one of the Foster wells. We do not have daily records back to that point, so I was never able to reconstruct it.

But this concept of the damage is what I was talking about with Mr. Stogner. I did not have evidence of this, basically because we're not in the habit of shutting in good wells. It's just not something we're in the habit of doing.

Q. On Exhibit 9, Mr. Fant, I think this is the sample of 17 production plots where you're showing oil cut versus oil rate?

A. Yes.

Q. Did you attempt during this period to test any of these wells, producing them at 700 a day for a period of time in establishing an oil cut at 700 barrels a day, and then coming back and establishing its oil cut at its maximum pump capacity, which would have been in excess of 700 a day? Did you try any of that kind of stuff?

A. Well, if you'll look at several of them -- You can go back and you can look at the Cutter. It's got a couple of data points that are almost exactly at -- It's about, oh, seven or eight back into it, the Cutter "APC" Number 1.

It's got a number of data points right there at 700, and you can see that that's at the low 30s. And then you've got a data point out at 1400 where it was at 48 percent, roughly, and two or three data points around 1000 where it's roughly at 40.

So yeah, I'd say that basically illustrates your point right there very well.

Q. Let's look at them. The first one here is the Aparejo Com 3.

A. Uh-huh.

Q. It shows an oil cut just above 30, oh, about 35 percent, at -- What's forecasted here on the curve, it's not an actual data point, but read over on the horizontal line and estimate 700 a day. Read up and find the line, and it looks like an oil cut of about 35 percent, right?

A. Yeah, probably a little more.

Q. And then when it goes up above 1000, it bumps 50 percent?

A. Yes.

Q. So there's an example that supports your position, right?

A. Yes.

Q. All right. We look at the next one in here, and it's 600 a day. It in fact does better than 50-percent oil cut. And in fact those data points don't change all the way up until probably 900 barrels a day. And then there's a small increase if it goes above 1200. So for that well, there's a little benefit at the higher rate?

A. Yeah, but if you'll remember, this well is in South Dagger Draw. It has an allowable of 1400 barrels a day per spacing unit, so it's allowed to produce up there.

Q. Oh, so this one's okay then? This one works?

A. But it just illustrates the point I was exactly trying to make with it, yes.

Q. The next one is the Boyd State Com 2. It apparently doesn't have the capacity to produce more than 600 a day, and so it could be produced at its pump capacity and not violate the oil allowable for the North Dagger Draw?

A. If it were the only well on the spacing unit.

Q. Okay. And you're concerned about shutting in the other wells in the spacing unit, because you believe that the shut-in is going to cause it to come back later at an oil cut that is less than it enjoyed early on?

A. I believe the data demonstrates that, yes.

Q. And again, the only data you've given us to support that point is the Polo 6 well?

A. I believe that illustrates the point very well, yes.

Q. All right. Exhibit Number 21 is, I think, one we saw at the Examiner Hearing. It was your presentation of what you anticipate would happen if you cycle one of the high-capacity wells using a 24-hour cycle, and then you used a 12-hour cycle.

I think it was your conclusion that cycling using this strategy was not going to be a beneficial way to produce this well under the restriction, something to that effect?

A. Basically what I was saying is that cyclic production is the same as restricting it, as -- You know, cyclic production is no different than just continuously producing at the lower net rate.

Q. All right. Did you actually cycle any of these wells using this strategy?

A. Basically all of the wells were cycled. Well, all but -- Well, all of them were originally cycled, and one of them we actually ran a smaller pump in.

Q. So what is Mr. Collins doing in the field to achieve the levels of restriction that you're currently operating under?

A. He is doing two things. In some instances he's running smaller equipment, in some instances he's cycling production. He's doing what is operationally feasible.

Q. Okay. Have you field-tested any other method to try to achieve the allowable restriction?

A. Yes, in the State K 3 we just simply -- after the -- We had an existing large-volume pump in there when it burned up. This was -- Remember, this was the one -- the well that only has one well on the spacing unit. And when, through having to turn that well on and off, we prematurely burned up that pump -- And that's basically because actually the start-up time period for a submersible pump is the most violent period of time, it's the hardest period of time on the pump. So making it start a bunch of times and you just -- you're going to wear it out much faster.

And when we ran -- we were cycling that pump, it burned up prematurely. And Mr. Collins instead of saying, Hey, let's put in another big pump and burn it up, let's just put in a smaller pump.

And so we ran a smaller pump, and that well was actually not even -- with that smaller pump was not able to produce the 700 barrels a day. So that was continuous reduction. And that was actually one of the larger reductions in oil cut. And no well -- None of the wells that we restricted, no well out there, improved in oil cut. None of the wells that we restricted improved in oil cut because of the restrictions.

Q. The data you've presented on those restrictions is limited to what we've seen on Exhibit 22, which is the plot of that data?

A. Yes, sir.

Q. Do we have available the actual numbers so we can see the total fluids withdrawn by the well and determine the amount of oil and water produced in relation to total fluids during the restriction?

A. Well, we have filed production reports on them, so you do not have it on a daily basis, but you do have it on a monthly basis, and this covers several months of data, so -- I mean, you know, the data exists in the public record.

Q. You created a model on one of these wells, Exhibit Number 20, on the State K 3 well?

A. I don't believe so.

Q. I'm sorry, which one was it? All right, I've tagged the wrong display. It was on the Savannah State display. Here it is, it's Exhibit Number 19.

A. Okay, yeah.

Q. All right, what I need to ask you to look at, Mr. Fant, is Exhibits 19 and 20 together.

All right, the Savannah State, based upon your modeling, you've attributed a calculated 29 acres of area contributing to the production in the Savannah State well?

A. I have calculated that the compartment size is 29 acres, yes.

Q. On Exhibit 20 for the State K 3 well --

A. Uh-huh.

Q. -- have you attempted to model that to see how many acres are contained within the compartment for which that well produces?

A. No, sir. As I mentioned before, this first one took me over a week to do. I do not have enough time to do them all.

Q. Okay. I'm interested in the swabbing oil cut relationship to the second month of production. It's your Exhibit Number 8.

A. Uh-huh.

Q. Again, this is a display we saw at the Examiner hearing.

A. Uh-huh.

Q. You've not updated it or changed that display, have you, sir?

A. No, this is the exact exhibit. I have changed one thing. I have included the diagonal line through it for visual reference.

Q. All right. If I remember correctly, it was your decision not to use the first months of production for that oil cut. Instead, you chose the second month's producing oil cut for these wells?

A. Uh-huh.

Q. Right? You chose not to use the first month's oil cut, because that data -- in fact, you characterized it to be unreliable?

A. I consider -- Yes, I consider the first month's production somewhat -- first month's -- I consider the water production in the first month to be a suspect number because of completions. Generally the oil is accurate.

Q. All right. The swabbing oil cut is taken very early in testing and producing the well, is it not?

A. Yes.

Q. Would not that data also be unreliable to determine the oil cut from swabbing tests?

A. No, sir. That data is not based upon what's reported to the State or not reported to the State. That data comes directly off the drilling report, off the actual completion report of the well. So --

Q. I don't have trouble with the number; I have trouble with the fact that you don't have stabilized production data in a swabbing test that will give you an accurate data point for your oil cut.

A. What I'm showing on this thing, on this particular plot, is that when you produce the wells at a low rate -- and that's what swabbing is, producing them at low rates -- you get much lower oil cuts than you do when you produce them at high rates. I'm not speaking to stabilization, I'm not speaking to pseudo-steadystate flow.

I'm simply saying that when you produce the well at low rates, you get low oil cuts; when you produce the well at high rates, you get high oil cuts. And I also state that there is no direct correlation between swabbing oil cut and producing oil cut, other than producing oil cut is generally very much higher.

Q. I'm having trouble understanding how this exhibit is useful for the Commission to understand whether the oil rate for a spacing unit goes higher than 700 a day. This does not tell us anything about that issue, does it, sir?

A. This is strictly to illustrate to the Commission that at higher producing rates you get higher oil cuts. That's what it's intended to show.

Q. Exhibit 10 is a tabulation of oil-cut slope versus GOR slope for 58 or 59 wells; I've forgotten the number. It runs for several pages.

A. No, this is -- Well, it's for a significantly larger number of wells than that. It's basically every well in Dagger Draw.

Q. I'm looking at Exhibit 10.

A. Yes.

Q. Yeah, okay. All right. When I look at the oil-cut slope, is this the second month's production oil-cut slope? Where am I getting this oil cut?

A. As I said in my direct testimony, the data for this is from the production history of the well, all production history -- all reported production history of the well.

Q. All right.

A. So this -- Yates Petroleum wells come from our database, our records, and the rest of them come out of *Dwight's*.

Q. Do we have volumes that you can show us associated with the oil-cut slopes so that we can see the total volume of water and oil that is calculated to reach this slope?

A. This slope is simply the slope of the line. It does not speak to a volume of water or a volume of oil. This is simply a mathematical slope of the line. It's just to indicate that there is a positive relationship between increasing the oil rate and increasing the oil cut. It simply demonstrates that if you increase the oil rate in wells in Dagger Draw, you increase the oil cut and conserve reservoir energy.

Q. I wanted to see the total volumes of withdrawal because I would assume that would be an important number, to see how much oil you produce in relation to the total withdrawals of fluids by that well. Do we have that analyzed somewhere here?

A. No, this is simply the slope of the line, as shown on Exhibit -- go back -- as shown on Exhibit 9. It is simply the slope of the line, indicating there is a relationship between producing rate and the oil cut, showing that at higher oil rates, you get higher oil cuts.

Q. When I read the oil-cut column, slope column, then, if it's a positive value, that means I'm getting a higher oil rate and therefore it's better?

A. Yes, sir.

Q. And if I see a negative number, that is a well that is producing at a higher water cut and a lower oil cut?

A. That the -- As I said in my direct testimony, there are some of these that are negative. They're due to statistical aberrations. You can look at the Aspden 2.

Q. Well, that's what I'm looking at.

A. That's a very --

Q. Let's start with that one right there.

A. It's a very --

Q. This one is in the violation area, and yet it has a negative 2.68?

A. No, it has a negative 2.68 times 10^{-5}. So you've got to move -- you've got to put four zeros in front of the 2, and put a decimal point in front of that. That's an extremely small negative slope.

Q. When we read down and look at the Binger "AK" 2 and the Binger "AKU" Com 1, these are also negatives, but they have a power of five and six, so you're still saying it's a small change?

A. They have a power of minus five and minus six, which makes them very small numbers. In fact, the data from the Binger 2 showed that it actually -- when we restricted it, its oil cut went down, and it's based upon the data that I presented about the Polo 6. When you have these calculations in this area, it's basically a statistical aberration due to the well's ability to flow oil to the surface.

Q. There's nothing changed on this exhibit from the one that Examiner Stogner saw in the May hearing?

A. No, sir, this is the same exhibit.

Q. If you'll turn with me to Exhibit 16, this is the -- It says "Canyon Completion Pressures and Field Production Versus Time".

A. Yeah, just a minute. Yes, sir.

Q. You've plotted some pressure points in here. I'm more interested in the oil volumes that are shown on the display post-January, 1987.

A. Post-January, 1987, there are -- Okay, yeah.

Q. The green line down there.

A. Yeah.

Q. We've got a jump in the producing oil volumes that you've analyzed.

If I remember correctly, your discussion was that original pressure in the 3000 pounds, give or take, have been produced for a number of years, and the consequence of which is that you believe it had closed the fracture systems in the reservoir and made the reservoir more compartmentalized, right?

29.

A. Okay. Just a moment, I haven't been able to --

Q. Yes, sir.

A. -- put my fingers on that one yet.

Yes, okay.

Q. All right. The first production plot on the lower left -- The first one on the lower left is what is forecast based upon production for the first well in that spacing unit?

A. Uh-huh.

Q. It forecasts if you take it down to a zero rate, you're producing just over 300,000 barrels, right?

A. Yes, yes.

Q. Then when the second well is added, the combination of those two wells are plotted next as we move to the right?

A. Yes.

Q. And that combination of two wells, now, will produce, oh, about 550,000 barrels?

A. Yes, sir.

Q. Okay. What does it cost to drill and complete these wells? What kind of range are we in for price?

A. Well, they're about $700,000 to sometimes $800,000. There have been some that come in under $700,000.

A. Some of the fractures closed, yes. I won't say that all of them did, but the evidence strongly suggests some of them closed, yes.

Q. If that evidence suggests that, what is providing the means by which you're achieving the high productivity of these wells drilled later in North Dagger Draw?

A. The matrix in this reservoir is still quite permeable. The matrix is good rock.

And just like I said before, we're drilling in areas that we weren't drilling in four, five, six years ago. We're drilling in new areas. And as Mr. May said, that the deposition -- It's individual facies within this reservoir that are -- create the reservoir rock. And we have to be in areas where the facies are much better.

Furthermore, many of our wells are not producing that much more fluid than they used to -- than other wells used to produce; they're just simply producing a lot higher oil cuts than they used to, which again speaks to the closure of the fractures and the matrix, and more of the flow moving through the matrix and having oil come into the wellbore from the reservoir instead of having water come into it.

Q. I'd like you to look at your Exhibit 15. It has two parts to it. I'm interested in the first page. It shows production decline curves in the southwest quarter of

Q. Well, it looks like, at least from a layman's point of view, that you can drill the two, the 550,000 looks to be profitable for wells that cost that.

And then you add a third well.

A. Uh-huh.

Q. And for the third well, you achieve additional recovery of only 100,000 barrels?

A. Yes.

Q. Okay.

A. Small compartment for that well.

Q. Uh-huh. And so we've spent another $650,000 to achieve 100,000 barrels?

A. Uh-huh.

Q. Is that still profitable to do?

A. Actually, yes.

Q. And then we go on and drill the fourth well, and at that point there's a dramatic change in the slope, is there not?

A. Oh, yes, yes, there's a dramatic change in that slope.

Q. What accounts for the dramatic change in slope?

A. This particular well is a much higher-rate well. It has the capability to drain its compartment faster. I mean, that's the facts of it.

Q. Part of its recovery is recovery that might have otherwise been produced by one or more of the original three?

A. I don't believe so, because I've looked at the interference data for these wells, and they show no interference. The other wells did not change in how they produced when that well came on, so I don't believe that there would be any interference there.

Q. Okay.

A. So none of its reserves would have been recovered by the other well. So they're definitely -- You know, they're unique reserves.

Q. Under that analysis, what is the estimated recoverable life, if you will, of the spacing unit using four wells?

A. This does not speak to the recoverable life. This speaks to the recoverable oil.

Q. I understand that. Have you plotted or estimated how long it will take to recover this oil?

A. No, I haven't.

Q. I'm curious about the life of the reservoir. I'm curious about whether or not at this point in time in the reservoir there is enough remaining oil that if your wells are shut in to balance with the pool, there's enough remaining oil for the others that in fact that shut-in means something to those that have not exceeded the producing allowable?

A. I believe if you'll look at this particular proration unit, it would only -- to shut it in would only require -- and I am, forgive me, talking off the top of my head -- but it would only take a few months, five months, in that time frame, of being shut in.

Q. To balance --

A. To balance.

Q. -- with its oil?

A. And it certainly has more life than that left.

Q. The forecasts here are using the wells at rates in excess of the allowable? I assume that's what's happening here.

A. This is not -- No, the forecast does not. These were -- Some of these wells produced in history in excess of allowable, but the forecast is based upon actually rates below allowable.

Q. I cannot, then, use this exhibit to show the difference between producing this spacing unit at the current 700 a day, versus 4000 a day that you're proposing?

A. This spacing unit, if you'll look at the last two data points on this particular plot, these four wells combined produce about 380 barrels of oil per day.

Q. So this spacing unit is not going to enjoy the benefit of an increased oil allowable?

A. No, I never said it would.

Q. When I was looking at Exhibit --

A. Well, let me change that. I really do want to make a comment. If they change -- If they cancel the overproduction, then yes, it will enjoy -- not enjoy the benefits; it will not be damaged by the 700-barrel-a-day allowable. That's important to understand. Forgive me.

Q. I'm looking at Exhibit Number 11, Mr. Fant. It's on the Diamond "AK" 1. This is a South Dagger Draw well, is it?

A. Yes, sir.

Q. I think so.

A. You're speaking of 11?

Q. Yes, sir. This --

A. Okay.

Q. In fact -- Yeah, the first page of this is a South Dagger Draw well.

Do you have anywhere in the materials production decline curves that will show us a well forecast production within the 700-a-day allowable, versus the proposed 4000-a-day allowable?

A. This well does not have a 700-barrel-a-day allowable. This particular well has a 900-barrel-a-day allowable set by Commission rule.

Q. I understand. I first looked at it and thought it was an example, but it's not. And so I'm asking you in the material that you brought today, do you have an example of production decline curves so that we can see what you would forecast to be the ultimate recovery from a well if it's restricted in a spacing unit for 700 a day versus the 4000 a day?

A. I don't have that exact thing, no. But you can take 7 percent of the restricted production, and that will not be recovered if you restrict it.

Q. When we looked at the table of -- on Exhibit 14, this is the one that shows the plot of part of the violation area, and it shows examples where you have concluded there is interference between wells?

A. Yes.

Q. Okay. Again, this was simply used by you to speak to your argument that you needed the option to have as many as four wells in a spacing unit, but I see nothing in here that addresses the rate at which to produce those wells?

A. No. My other data expresses the rate issues.

Q. All right. The drive mechanism in North Dagger Draw is simply gas expansion? We don't have an active water drive support for the pressure in the reservoir, do we?

A. Conoco has claimed that there is a weak water drive, especially in the areas of newer development. I don't even see evidence of a weak water drive. It is -- The drive mechanism is solution gas.

Q. I think we attributed the weak water drive to South Dagger Draw, but --

A. No, they actually attributed it to wells up on the northwest edge of North Dagger Draw, I believe, based upon Mr. Finley's testimony.

Q. I'm interested in your opinion, Mr. Fant. This is simply gas expansion?

A. Well, solution gas drive, not necessarily -- Gas expansion connotates gas-cap drive to me, but this is solution gas drive.

Q. Okay. And you're not at all concerned that the overproduction from North Dagger Draw has caused a pressure decline in the reservoir?

A. No, obviously, the data that I showed in my exhibits with the production and history of the well, you see we've ramped way up on production in the field, and the reservoir pressure in the new wells hasn't changed any.

So no, it has not created excessive pressure declines.

Q. When did you personally become aware that Yates had spacing units in Dagger Draw, North Dagger Draw, that were overproduced?

A. About the time I went and met with Mr. Gum, sometime around in there, yes.

Q. I'm sorry, sometime -- ?

A. About the time that I first met with Mr. Gum.

Q. This is in 1995?

A. Summer of 1995, yes.

Q. Do you recall more specifically what portion of the summer that you went to see him?

A. I believe it was June. I don't want to -- You know, I don't want to give an exact date because that would be talking too much, but I believe it was in June.

Q. All right. And that would be consistent with the fact that the production information shows that in May Yates had spacing units that were overproduced? We saw that at the last hearing?

A. Yeah.

Q. All right. Did you go to Mr. Gum in Artesia at the Oil Conservation Division Offices there?

A. Yes.

Q. And did you go with anyone else?

A. No, I was the only one that went there.

Q. Were there any other Oil Conservation Division personnel present, other than Mr. Gum?

A. I don't believe so. I believe it was just myself and Mr. Gum in his office.

Q. At the time you talked to Mr. Gum in 1995, do you know how many wells Yates had that had the capacity to overproduce the spacing unit allowable?

A. In retrospect it could be calculated, but no, I don't know that number.

Q. Did you have a number in mind as to the magnitude of overproduction?

A. No.

Q. When you went to see Mr. Gum, why did you go there?

A. I knew that we had wells that were not experiencing the declines that were natural -- I was fairly new at the time, working Dagger Draw. We had a reorganization recently, and I was getting my feet on the ground with Dagger Draw. And, you know, basically I realized, hey, these wells are not declining like you might expect.

And so I went to him and, you know, asked him if -- I had heard these rumors -- rumors or concepts, from people that, you know, in Dagger Draw you've got to produce them hard, because you get better oil cuts at higher oil rates. And I was interested in going to Mr. Gum and wanting to ask him if we could produce at even higher rates.

Q. All right. When you went to Mr. Gum, you knew the Dagger Draw rules for the maximum allowed production of 700 barrels a day on 160 acres, did you not?

A. Yes.

Q. Did you disclose to Mr. Gum at that time in 1995 that Yates in fact had spacing units that were being overproduced?

A. I disclosed to Mr. Gum that we had wells that were above allowable and were not experiencing the declines that were normal, and I did not say -- I did not use the words, "we have wells overproduced", but I indicated to them that we have wells that are above allowable and they were not experiencing a decline. So...

Q. You're very clear on the recollection that you disclosed to Mr. Gum in 1995 that you had spacing units that were overproduced?

A. You didn't listen to what I said. I said, I said to Mr. Gum that we had wells that were above allowable and that were not experiencing the declines that were normal out there. That's what I conveyed to Mr. Gum.

Now, the inferences anybody else wants to take from that, they can do that. But that's what I -- That's my absolute recollection of what went on there. Okay?

Q. All right. You didn't pose your problem to Mr. Gum as a hypothetical about, What do I need to do in order to produce these wells at rates larger than the allowable?

A. I wanted -- My hypothetical was, How do I get to produce them at even higher rates? That was the hypothetical.

Q. Describe for me --

A. If we had a miscommunication, then that was a miscommunication, but that's what I was conveying to Mr. Gum at the time.

Q. All right. What were you asking Mr. Gum to tell you?

A. I wanted to know -- See, I was interested in running step-rate tests on these wells, to produce them where they are, which was high and above allowable at the time, try and increase it even more and even more, turn them up.

Q. Did you show Mr. Gum any production or give him a specific example of the possible rates that you were looking at?

A. No, sir, I did not. It was the preliminary meeting. He indicated we would have to have the approval of offset operators, and at the time that was not feasible.

Q. Describe for me the procedure for your proposed step-rate test to Mr. Gum in 1995.

A. You just heard it.

Q. Did you specify --

A. Produced wells --

Q. -- any specific rates?

A. I did not give any specific rates. I did not give any specific time periods. It was a hypothetical to get the issue -- to put the issue before him to say, What have we got to do? You know, I want -- It's important to me to make sure we get these wells produced right, and this is something we need to look at. How would we go about it?

Q. All right. You did not --

A. That's what --

Q. You did not leave that meeting, then, with the understanding that Mr. Gum had in any way approved Yates to overproduce the allowable?

A. No, sir.

Q. Okay. And after that, then, you did not pursue a step-rate test or any other producing testing for the well, because you were concerned you could not get offset operator approval?

A. Yeah, we basically felt that it would not be possible.

Q. And you never asked?

A. No.

Q. Okay. And the next time you address the overproduction is in March of 1996, when Mr. Gum is contacting Mr. Collins and advising you that he's discovered you've got spacing units in North Dagger Draw that are overproduced, and what are you going to do about it?

A. Are you speaking of me as Yates Petroleum?

A. Yes, sir.

Q. Okay. Yeah, he came to Yates in, I think it was early March, and said, We need to look at this and, you know, bring me a proposal. And he allowed us a time to prepare something for that.

Q. All right. And you were involved in the preparation of a proposal?

A. Yes.

Q. Did your proposal include an analysis of how to restrict these wells and bring them back into compliance in the spacing units?

A. Our proposal was to -- There were discussions between Mr. Collins and Mr. Gum about a time frame to take them in. But what we actually proposed was to restrict them to the 700-barrel-a-day allowable, not accrue any more overproduction, and to bring this matter before the OCD. We did it -- and to bring it as fast as we legally could, which we did.

Q. All right. where --

A. And we also restricted the wells --

Q. Okay.

A. -- immediately.

Q. During this period of time, are you conducting any field tests of wells to see what is their most efficient oil cut at which to produce them?

A. The most efficient oil cut to produce any well is the highest oil cut possible. And --

Q. Well, where's the 400- -- Where does the 4000 barrels of oil come from, then, Mr. Fant?

A. Just as I said in my direct testimony, it comes from the fact that basically the State K 3 -- When we set the Application, we didn't have the Polo 6 or the Patrick 4, but in the original Application, the best well we've had on a long-term basis is the Polo -- I mean, excuse me, the State K Number 3, which is basically a 1000-barrel-a-day well for a year. And that's where you drill four wells of that type on one proration unit, and you have 4000 barrels a day.

And that -- that's -- I'm not going to say, Let's go out there and make it 10,000 barrels a day, because I don't have the data at this point to say that. But I do have data that says that 1000 barrels a day per well -- per -- you know, with four wells on the spacing unit, gives you 4000 barrels a day. It's based upon well data.

Q. All right, and that level of allowable, then, equates to a capacity allowable?

A. Just like Conoco asked for in 1991, and Mr. Hanks asked for in 1976 -- 1975 or 1976, in that time frame, yes, sir.

Q. Was there any opposition to the Conoco request back in 1991?

A. To my knowledge, no.

Q. At that time, were any of those spacing units overproduced?

A. Absolutely -- Actually, I believe -- and I'm calling this from recollection -- I believe there was one or two spacing units in 1991 that were overproduced, yes, sir.

Q. Let's look at Exhibit 7 again. It's this colored plat. Tell me the data that you looked at and what information caused you to put a darker shading on the color for any of these spacing units to show they're overproduced.

A. I'm not -- I didn't say they are overproduced.

Q. No, sir, at any point in time they've been --

A. Okay.

Q. -- overproduced. Now, my point, is if they were overproduced for a single month --

A. Yes.

Q. -- then it's on the map?

A. Yes, if ours were overproduced for a single month, then they're on the map. If somebody else's were --

I did not -- It goes back to what I said before: I'm not drawing distinctions, I go straight by the numbers.

Q. All right. For example, if an operator of one of these spacing units drills an infill well, IPs it for a higher rate, produces it for that first month and reports a number in excess of the allowable, then it's noted on this plat?

A. Yes.

Q. At any point?

A. Yes.

Q. Despite the fact that the following month they may have curtailed that production and therefore every day after that abided by the rule?

A. The data that I've seen on most of these, when I've looked at individual ones, is not that they curtailed it the next month; it's that it declined the next month.

Remember, we talked about the rapid declines that are normally experienced in Dagger Draw, and most of them that did get overproduced, they declined the next month. And you can tell that it's declined because if it's restrictions then it goes flat, but if it's decline it continues.

And so it's not generally a restriction that brings it back into line but a decline.

Q. And typically in Dagger Draw, that decline was evident in the first month or two of production?

A. That would be typical, yes, sir.

Q. And you're seeing for your new wells in Dagger Draw that that was not occurring?

A. In many of them, yes.

Q. And we saw that in May of 1995?

A. It was evident in a few wells in May of 1995, yes.

Q. And those wells are produced for May and June and July and August and September and October and November and December, and you continued to produce them?

A. They were continued to produce, yes.

Q. We looked at the production information at the last hearing, Mr. Fant. I'm going to show you what was Conoco Exhibit 12 in that last hearing.

Exhibit 12 refers to the available production information that was presented in the May 2nd hearing. It deals with the southeast quarter of 29. The southeast quarter of 29 has got the Boyd wells in them.

What I'd like to discuss with you, Mr. Fant, is the strategy Yates is using with regards to adding wells to a spacing unit. In this example, the first well is produced, a negative number indicates that it is underproducing its allowable.

Under the allowable system for oil wells, you're not allowed to carry over underproduction, are you? You can't carry it over to the second month, can you?

A. I don't believe so.

Q. Yeah, it's not like gas prorationing where you can carry over underproduction, right?

A. I don't believe so.

Q. All right. So the second well is added in May of 1995, because the first well can no longer sustain a rate that allows it to meet the allowable for the spacing unit, right?

A. Yeah, it was never able to meet allowable for the spacing unit.

Q. So in May of 1995 you add the second well, and now the combination of the two wells will exceed the allowable, right?

A. Yes, sir.

Q. And it continues to do so. And in November of 1995, despite the fact that those two wells are substantially overproducing the allowable, Yates adds a third well and commences to produce that well?

A. Yes.

Q. Why are you doing that?

A. This one's just what Mr. Patterson talked about. This in no way represents the way Yates Petroleum normally developed them. We drilled -- That third well on that proration unit was drilled because a judge --

Q. The judge made you do this?

A. A judge was interested and wanted that well drilled, because there were legal issues involved in this. That's my understanding of it.

Q. Did he tell you to drill it and produce it?

A. He didn't tell me anything.

Q. All right.

A. But we drilled it based upon that.

Q. Are you working with Mr. Collins, the operation manager, on the sequencing of adding new wells to these spacing units? Are you involved in that?

A. Mr. Collins does not have, generally, much input into when new wells are approved for -- to be drilled. I mean, he certainly as the operations manager has some. But he's primarily -- He doesn't approve the drilling of the wells.

Q. Are you making the decisions for Yates on adding infill wells in these spacing units?

A. No, sir.

Q. All right, does Mr. McWhorter make those decisions?

A. No, sir.

Q. Who makes the decision?

A. Generally, locations are approved by S.P. Yates.

Q. During the summer of 1995, prior to Mr. Gum talking to Yates in March of 1996 about the overproduction, did you continue to be aware of the overproduction?

A. I was aware of it.

Q. Did you report that overproduction to any of your supervisors in Yates?

A. I believe they were aware of it.

Q. Did you ask for guidance and instruction on how to handle the overproduction?

A. That is not my responsibility at Yates Petroleum.

Q. Did you receive any direction from supervisors or management on what to do with the overproduction?

A. No, sir.

MR. KELLAHIN: No further questions, Mr. Chairman.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Questions of the witness?

Do you have some redirect, or after --

MR. CARR: Very brief.

CHAIRMAN LEMAY: Go ahead, Jim.

MR. BRUCE: Just a couple.

EXAMINATION

BY MR. BRUCE:

Q. Mr. Fant, referring to your Exhibit 14 --

A. Give me some help.

Q. -- the interference chart --

A. Oh, okay, yeah. All right, yes.

Q. Okay. You know, looking at this map there's a number of undrilled locations here.

A. Yes, sir.

Q. And on these undrilled locations is it possible to tell whether there will be interference before the well is drilled?

A. Absolutely not.

Q. Were some of the -- I presume, but correct me if I'm wrong, that a number of these locations aren't drilled or haven't been drilled because of overproduction?

A. Yes, our practice is to -- We don't drill these wells, except in this one instance that has been pointed out to you where the judge basically wanted us to drill the well. But the wells would not be drilled -- additional wells would not be drilled on a spacing unit unless we were below the 700-barrel-a-day allowable.

Q. So if the allowable was increased, some of these wells could be drilled and produced?

A. Yes.

Q. Okay. Some of them could be drilled now, but it would be not reasonable to produce?

A. We could drill them all, but they couldn't -- they essentially -- The net effect is, they could not be produced.

Q. And then one final thing. What you're saying is that the effect of any fracturing in the dolomite is limited or eliminated using fractures closing under pressure decline?

A. I believe -- I didn't quite hear that well enough. I'm sorry.

Q. I'm asking the effects of the pressure, any pressure decline, on the fracturing, that severely limits the effect of its fracturing in the reservoir; is that what you're saying?

A. I don't know that there's enough data at this time to say that all fractures get closed. But they don't all have to, to create the compartmentalization, just some of them do.

We deal -- In these reservoirs, we generally deal in what is called series flow so that -- It says that if at any point you have a barrier, you have a barrier. Okay, if at any point we stop flow, flow can't go through there.

So just -- You know, you don't have to close all the fractures, and I'm not willing to say at this point that all fractures in the system are closed. But I do believe that some of them are.

MR. BRUCE: Thank you.

CHAIRMAN LEMAY: Mr. Carr, do you want some redirect?

MR. CARR: Very briefly, just...

REDIRECT EXAMINATION

BY MR. CARR:

Q. Mr. Fant, to be sure there's no confusion, earlier this afternoon Mr. Kellahin was talking to you about the value of overproduced oil and how that would relate to the value of the oil that you would not be able to make or produce while making up the overproduction. Do you remember those questions?

A. Vaguely, yes.

Q. We're not talking in that scenario about just taking money out of one pocket and putting it in the other, are we?

A. No, sir.

Q. When -- Isn't the problem with being overproduced and then having to shut wells in to make it up, that ultimately you come out with a 7-percent reduction in that delayed production?

A. Yes, sir, that's what happens. You lose that oil forever.

Q. And you also lose the revenue associated with that oil?

A. Yes.

Q. That means the working interest owners?

A. Working interest owners.

Q. It means the royalty interest owners?

A. Yes.

Q. And it means the State of New Mexico?

A. Yes, through royalties and production taxes and income taxes.

Q. Now, several times this afternoon Mr. Kellahin said that after meeting with Mr. Gum about step-rate tests, you didn't go out and talk to the offsets, did you?

A. No, sir.

Q. You did not?

A. No.

A. Did the offsets include Nearburg Producing Company?

A. Yes, sir.

Q. Was --

A. In the area -- In the area where the tests were feasible to run, Nearburg was an offset operator.

Q. And wasn't Nearburg -- Wasn't this during the time of what I think Mr. Kellahin characterized as the war between Yates and Nearburg?

A. Yes, sir.

Q. All right. Did Judge Schuler tell you to drill a well and then not produce it?

A. I don't know. I don't believe so.

MR. CARR: All right. That's all I have.

CHAIRMAN LEMAY: Additional questions of the witness?

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. The lack of decline that you noticed in the wells in this overproduced area, beyond that first or second month, is that unique to Yates's wells in this area, or are the other operators also experiencing that lack of expected decline?

A. Well, I think the fact that -- For as big as Dagger Draw is, there's actually very few operators involved in it. There's only about six operators ion it. Yates has wells like this. Nearburg has wells like this; theirs are overproduced. And Mewbourne has wells of this capability.

So 50 percent of the operators do have wells, but they're all basically in this area of new development. So it's not a unique situation to Yates.

The magnitude, I think, is -- of Yates' overproduction stems from -- there are some exceptional wells in this area, and we do happen to operate most of the area.

Q. Exhibit 10, the listing of all the wells with the

oil-cut slope and the GOR slope --
A. Uh-huh.
Q. -- do those include wells for both the North and South Dagger Draw, or are these unique to --
A. No, these do include North and South Dagger Draw.
Q. I noticed that the Savannah well and the Polo "AOP" Number 6 that we have on other exhibits are not included in this listing?
A. No. With regards to the Savannah well, when I generate -- This exhibit is exactly as I presented in the Examiner hearing in May, and I did not have data for that. There was a requirement that I have at least like three months of production data on it, otherwise the statistical technique is not even remotely valid. If you only have one month, you can't put a slope on one data point. And somebody in college told me one time that it takes three points to do a regression. So I like to have those.
So the situation with the Polo is, the Polo was completed in August, and so -- the Polo and the Patrick and all these other -- It's much too recent. These wells are too new for that, for me to do that.
Q. But that's the only criteria of whether or not a well is included in this list?
A. Yeah, I just did not have the data at the time that this was generated. This is a tremendous number of

calculations to do this, and I just -- I did not update it.

Q. Exhibit 14, which shows the known instances of interference --

A. Uh-huh.

Q. -- these are all Yates wells showing interference, according to looking at this map of Exhibit 7?

A. Yes.

Q. Were any calculations made to see if there was interference with adjacent spacing units in other sections --

A. Yes, and in fact --

Q. -- 17 and 30?

A. -- all of these were examined as to how they might interfere with the adjacent sections also. I just happened to -- The adjacent sections weren't what I considered to be this new area of development. In retrospect, I probably should have added the two sections, Sections 32 and 33, where Conoco drilled their Joyce wells and their Savannah wells and where Mewbourne drilled their State B wells.

But no, in all instances I looked through, none of these areas are interfering with wells outside of them.

Q. Okay, because I'm looking at Section 17, which has the northeast quarter of Conoco, which has overproduced at some point, at least for a period.

A. Uh-huh.

Q. I don't see --

A. No, yeah, this particular thing is only Yates wells.

Q. Okay.

A. This map only shows the Yates wells. Section 17 was omitted because -- In my original of thoughts it was Conoco. But I did look at all of the possible interference going outside and there was none.

Q. Is fracture stimulation a normal SOP for completion of wells in this area?

A. Well -- Forgive me, I may have misconveyed that. The stimulation practices -- We do not fracture-stimulate these wells. When I was talking about the fracture stimulation and the closure and crushing of the fracture, I was just talking about how fractures close.

We do not fracture-stimulate these wells. These wells -- And in fact, one of the things Mr. May said was that, yes, that completion procedures have changed over the years, but they really for the most part -- Since 1971, yes, they've changed. But since 1989 for Yates Petroleum, completion procedures have remained fairly consistent. We acidize the wells. We perforate them, and we acidize them, generally with volumes of 20-percent hydrochloric acid.

Q. I believe you made the statement that interference between the wells does occur, independent of the rate. But doesn't the rate interfere with correlative rights?

A. Well, in their cross-examination of Mr. May they were basically insinuating -- or maybe Mr. Patterson -- they were insinuating that at the original hearings all the data was presented that at 700 barrels a day there was no impact on interference or anything like that.

And I made the statement about, Interference is not caused by rate; it's caused by pressure communi- -- it's caused by a communicating stringer between one well and another. If there's a communicating stringer, the only way to adequately protect correlative rights is to make sure that both wells are able to withdraw from that stringer at the same rates, at the same type pressure drawdowns. That's the only way to fairly do that.

So the only to protect the correlative rights where there is interference is to produce the wells at capacity, because both wells must be allowed to withdraw from that stringer at the same rate.

And the only way to make that -- the only way to control that is to let them produce at the capabilities of the well. If you artificially -- put some artificial restriction, which is exactly what 700 barrels a day is, it's an artificial restriction that no longer has any bearing on the productive capabilities of the well. When you put that artificial restriction on it, then the one you're damaging is the person -- is the operator with the better well, because the poorer well may only have that one stringer and they're allowed to pull 100 percent of their production out of that, and if they can make 700 barrels a day, they're allowed to pull 700 barrels a day out of that stringer.

But the offset operator may have production coming from other stringers, and so they're not allowed to pull 700 barrels a day out of that one correlative stringer.

And therefore the operator with the better well, their correlative rights would be impaired in that issue.

I know it's contrary to what has been so long thought, but when you sit down and put the numbers to it, the numbers speak that we need to produce the wells at their rates, at their capabilities.

COMMISSIONER BAILEY: That's all the questions I had.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yes, sir, Mr. Fant. I've got a basic question about whether the wells are pumped off.

A. Uh-huh.

Q. On Exhibit 12, the one that you just got overproduced, Number 7, this one we just picked up --

A. Uh-huh.

Q. -- that first well, was it pumped off?

A. The first well most certainly was pumped off. I mean, it was producing at the physical capacity of the well.

Q. Okay.

A. The second well was not.

Q. Okay. But you're over anyway, so --

A. Uh-huh.

Q. But the first one was. And by and large, I guess that's another question I had, on Exhibit Number 10. I believe that's your tabulation of all the different wells --

A. Uh-huh.

Q. -- and that correlation of the increase in the oil cut with the rate?

A. Yes, sir.

Q. Now, did that correlate with the initial rate? I mean, with the pumped-off business? Do you get the drift there?

If the initial rate was quite high and the well was pumped off initially, you couldn't make it go up, I guess --

A. No.

Q. -- you couldn't make it go up?

A. No. And I'm not -- I hope I didn't misconvey myself. I'm not saying that we need to take every well in Dagger Draw and turn it up to 4000 barrels a day. There are places where that's not possible, just -- you know, the southwest quarter of 29. It's not possible.

But there are places where it is possible, and that's where the focus needs to be. There would be no -- essentially no impact on the ones where it's not possible.

Q. Well, these are just a matter of curiosity --

A. Yeah.

Q. -- on my part, whether the wells are initially equipped to be pumped --

A. Most --

Q. -- or do you learn that by trial and error?

A. No, most of the wells are initially pretty well pumped off, most of the wells. These wells that we -- most of these -- and I say most of the wells. Most of the wells throughout the entirety of Dagger Draw --

Q. Uh-huh.

A. -- the data used to prepare this chart -- I mean this tabulation of data -- is probably 95-, 99-percent pumped-off data, okay? Because this is historical production.

Q. So total fluid stays the same, but the oil cut went up; is that what you're saying?

A. No, total --

Q. The rate, the oil rate went up, so the -- And as the oil rate goes up, the oil cut goes up? That's what you're showing us?

A. Actually, on most of this it's because the oil rate went down, and the oil cut went down because of decline. This is historical production data, this -- showing that as the oil rate went down, the oil cut went down. It's illustrated to show that -- over time, that this relationship exists.

Q. Okay. So that is -- I didn't understand that.

A. Yeah.

Q. So the information in this compilation of 100 wells or so does not, I guess, fit with these curves here where you actually increase the rate on Exhibit 9.

A. No.

Q. The rate had to increase -- Or was it high and then gone down?

A. Most of these were right to left. Time on most of these would go from right to left. Okay? So the initial times they were at high rates, and the later times they were at low rates. That's the case on -- and I'm simply -- I present those to say that this is examples of this data right here.

Q. Okay.

A. The difference being, when you move to Exhibit 11, that is some where we turned them up and turned them down.

Q. Okay. Now, did you do that -- That's another question there, you turned it up and you turned it down. Was it always one way, just up, or did you vary it, go up and down like you would a step-rate test?

A. In the Diamond "AKI" Number 1 we started at 800 and 28-percent oil cut, we went to 1300 and 35-percent oil cut, and then we turned back to 900 and a 30-percent oil cut.

Q. Okay.

A. So we went up and down on that one. That's why I feel that's such a very powerful example of what was going.

In the case of the Aparejo 5, the second one, we simply went from low to high.

Q. Okay, that's what I thought you said.

Now, in the gas cut going down --

A. Uh-huh.

Q. -- the GOR going down -- Is there any gas injection in this area?

A. Oh, no, sir.
Q. Let's see, what the heck. I had another question on 13, if I can find it. Oh, yeah, your withdrawal comparisons.
A. Okay.
Q. Is the static reservoir pressure the same on both of these wells?
A. The static reservoir pressure? At some point in time after they were drilled?
Q. Yes.
A. I do not have measurements of the static reservoir pressure after drilling. I believe that the static reservoir pressure in the Thomas 6 is higher than in the Warren.
Q. Well, I guess my point was, could this be just that what we're seeing here is one well is three times as permeable as the other?
A. No, I believe if that were the case, then it would not show additional reserves to be recovered in this pool.
And this one shows that 71 percent of the reserves in the Thomas 6 would never have been recovered by the Warren 1, or because there's no other interference with any other wells, it would never be recovered by any other well.

Q. And that's seen on one of the rate-versus-cum curves?

A. Not these particular ones. That's -- Basically, I took the decline through the first five data points for the Warren Number 1 and then extrapolated that out, and then I took the new decline rate and then -- and said, Okay this much has been impacted.

But this well, this particular well, is not presented on a rate-versus-cum plot.

Q. You didn't have one of those?

A. No, and one of the reasons is, those rate-versus-cum plots in my system are set up to be generated and created on a spacing-unit basis, and these two wells are in different spacing units. I mean, I can force the computer to do something different; I just hadn't thought to do that at the time.

Q. Yeah, on Exhibit 16, the one with the measured pressure behavior, are there any -- This is all on newly drilled wells, this is your field --

A. Uh-huh.

Q. -- completion pressures and field production --

A. Yes, sir.

Q. Are there any pressures on the oil wells, producing oil wells, that would suggest that they're also 2000 pounds static reservoir pressure or...

A. My estimation would be that they would not be 2000 p.s.i., once they had produced for a time, because they're in their own little compartment for the most part, and the pressure does deplete within the compartment.

Q. Is there --

A. This compartment doesn't deplete the next compartment.

Q. Are there any measurements?

A. Just one back from the case presented by Conoco on one of their wells -- I want to say it's the Barber Fed Number 6 -- that after three years of production the pressure had been reduced to approximately 1150 p.s.i. from an original pressure of 2200 p.s.i.

Q. So that would be available probably later. Okay.

Let's see, I had a comment on Number 20. That's the State K 3?

A. Uh-huh.

Q. Now, does that indicate that reduced rates at least don't seem to damage anything? I guess I'm looking at the oil rate there.

A. The oil rate -- I don't think that this can be described as indicating that. This well is restricted down -- You know, it came down as restricted and over time came back up.

But I do know this specific well, when it was restricted, dropped from approximately 57- or 58-percent oil cut to -- I want to say 50. It had about a 7-percent change in oil cut when it was -- you know, about a month and a half after it was restricted.

Q. Okay. Oh, yeah, I missed Exhibit 21. I wasn't sure what was being compared there. This is a pressure a certain radius away from the wellbore; is that what we're looking at there?

A. Yeah, it's the pressure as compared against what the pressure that far away would be if you were producing at --

Q. -- constant rate?

A. -- constant rate. The same total net rate coming out of the reservoir. In one case you're producing it at twice the rate for after the one, in one case you're producing it at a constant rate.

Q. And this calculation, I would guess if I understood you right, doesn't include a fractured system?

A. No, sir, this is based upon a just a simple --

Q. -- homogeneous --

A. -- homogeneous system, very, very rudimentary but just to illustrate that cyclic production and continuous production have the same effect.

COMMISSIONER WEISS: And I think that concludes all my questions.

Thank you.

THE WITNESS: Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Fant, you -- Where do I want to start here?

You indicated the pilot waterflood was disappointing to date in this field?

A. Yes, sir.

Q. Do you anticipate doing something with carbon dioxide?

A. At this point I don't know what to do with it, in all honesty. If water- -- Generally, if waterfloods do not work, the probability of the CO_2 flood working is reduced. And so at this point I do not anticipate doing anything with CO_2.

Q. How much of the oil in place do you figure you'll get in this field?

A. We've never come up with what I considered to be a good stab at that number called oil in place. You know, I'm sorry, I've never been able to do that. I would estimate 10 to 15 percent, probably on the low end of that at probably around 10 percent.

Q. So we'd leave a lot of oil down there?

A. Yes, sir.

Q. You made a comment, Yates is not in the habit of shutting in good wells?

A. I would not say that that's necessarily just Yates, but most companies.

Q. This goes back, probably, before your time. I raised the issue of the Bough C before, with submersible pumps in the -- actually the early Sixties.

A. Uh-huh.

Q. Are you familiar with that at all, that time frame of production?

A. You know, forgive me, no, I'm not familiar with the early --

Q. Well, the allowables were 30 barrels of oil per day rather than 90 at the time --

A. Yeah.

Q. -- and there were submersibles on Upper Pennsylvanian reservoir, and there was curtailed production.

A. Uh-huh.

Q. From all your testimony, I was getting the impression that if you curtail production, you're losing a lot of oil --

A. Yes, sir.

Q. -- in most reservoirs that have high water cuts. I don't know if -- That generalization is what I'm trying to get at.

A. Most reservoirs that have these high water cuts, it's related to a water drive, okay? You know, either a bottom water drive -- many of the Ellenburger reservoirs, say, over on the -- The ones I'm probably most familiar with are the ones in central Kansas, which are, you know, bottom water drives.

Edge water drives are most assuredly rate-sensitive, and you do need to produce them at maximum capacity.

This one has to do, I believe, with the mechanics of how the reservoir is responding to drawdown, in Dagger Draw, and the way that the permeabilities are changing.

There's a lot of work going on now that's showing that -- You know, we as reservoir engineers for many years have taken permeability, system permeability, as a constant number, and what we're finding out is, it's not. As we change the pressures on the system, it's -- that number can change, and in different parts of the system it can change. It can change in the fractures faster than it can change in the matrix.

And so that can help us in this instance, and I believe it is actually helping us in this case.

Q. My point was only to add a historical perspective --

A. Oh, forgive me.

Q. -- to the sense that there haven't been operators curtailing production when they've had good wells. And I would challenge that, because there's a lot of curtailed production during the time of low allowables and better production, especially in the early 1960s and late 1950s --

A. Oh, yes, sir.

Q. -- and I assume many operators were either shutting in wells or curtailing production, similar to the overproduction situation you find yourself in here.

This is not a unique situation, I guess, was my comment. Operators have found themselves in situations where they're either overproduced or they need to curtail production or they become overproduced. They didn't go out there and just produce because they thought it was in their best interest.

A. That -- You know, my experience in the oil industry began in 1984, and so --

Q. Mine began in 1956, so --

A. Yeah. So, you know, unfortunately mine -- and it was not -- you know, I did not -- you know, the recommendations, I don't know where they came from within the company to produce them at the rates that they were. I just -- You know, my mental perspective is since 1984, in America, we've been trying to produce as much oil as we can.

Q. That's true.

A. But --

Q. And we have -- Again, we've had hearings, numerous hearings, especially during the crisis in the Middle East, where we encouraged operators to come in and we'd raise our allowables if they would put on hearings for MER.

And we did, we raised numerous fields, the allowables, from the existing level when there's evidence shown that that was the maximum efficient rate to produce the field at. And everyone has that opportunity.

A. Yes, sir.

Q. I want to go back to your compartmentalized model because what I'm visualizing is, almost each 40 acres, now, is its own separate reservoir, with very few stringers that are extending between wells. Is that kind of the way you visualize this reservoir?

A. Well, that's one of the first things that comes to mind. And I've been asked the question, Are these things 40 acres in size? I don't believe that they are 40 acres exactly, in size. I don't believe they're all the same size.

I don't believe that all the compartments on a -- You know, within a well, you've got vertical stratification, and each one of those will have its own compartment. And each one of those will be of a different size.

I know I've calculated with the Savannah State Number 1 that its compartment, the average of its compartment size, is about 29 acres. So I know that they can be significantly smaller and that there are some that extend -- I'm concerned at this point that we're still not recovering all the oil that can be recovered out there, because we are seeing only limited communication between the wells, and -- Yeah, I'm not saying at this point that I want to drill more wells.

Q. I was going to say, would you recommend 20-acre well density?

A. Not at this point, no, sir. I believe -- you know, when you start doing the calculations now, based upon what we know the porosities really to be more closely to, the recoveries seem more reasonable.

Q. I wonder if you'd look at your pressure. I guess it's Exhibit 16. I want to take this back to your model.

You start off with original bottomhole pressure close to 3000 pounds. You withdraw, you said, approximately 39 million barrels of fluid or fluid equivalent.

A. Uh-huh.

Q. And then you start -- you continue to get pressures in the range of 2000, 2200 pounds.

Why wouldn't you expect with these undrained zones or cylinders to get the 3000 pounds?

A. It goes back to the concept that I believe in order to trap the oil in Dagger Draw we had to have the water movement throughout the reservoir. From one end to the other, we had groundwater movement.

That's what tilted -- That's what put oil downdip in North Dagger Draw from oil updip in South Dagger Draw, this groundwater movement through there. So -- And it was the fracture system that created this pathway to do that.

Okay, in order to close some of these fractures, to get them closed, we had to deplete the pressure throughout the fracture system. If we don't -- Which in turn reduces the pressure in the compartments, because the fractures while they're open are connected to the compartments.

So to close the fractures we must essentially lower the system pressure to about 2200 -- You know, and I say 2200. In some places it went lower, in some places they seemed to close off around 2500 p.s.i. Some places they didn't close till 1600, 1800 p.s.i. That just speaks to not all these fractures closed at exactly the same pressure and time.

But the net -- You know, not the net but the average pressure over this time really hasn't changed, and it hasn't continued to go down in these things. So basically --

Q. So you're continually finding new reservoirs with closed fractures?

A. Exact- -- that's basically the concept, yes, sir.

Q. I believe that's all the questions I had.

Will you be available tomorrow if we need to ask additional questions after hearing Conoco's presentation?

A. Absolutely.

CHAIRMAN LEMAY: Any other questions?

COMMISSIONER WEISS: No, thank you.

CHAIRMAN LEMAY: Any other?

COMMISSIONER BAILEY: No.

CHAIRMAN LEMAY: Thank you, you may be excused.

THE WITNESS: Thank you.

CHAIRMAN LEMAY: Hey, it's 4:30. Let's start tomorrow, huh?

MR. KELLAHIN: Yes, sir.

CHAIRMAN LEMAY: 8:30 okay?

MR. KELLAHIN: 8:30 is fine.

CHAIRMAN LEMAY: We'll see you tomorrow.

Do you have any more witnesses, Mr. Carr?

MR. CARR: No, that concludes the direct presentation of Yates Petroleum Corporation.

CHAIRMAN LEMAY: Thank you.

MR. KELLAHIN: We'll start at 8:30 with our geologist, then, Mr. Chairman.

CHAIRMAN LEMAY: All right, thank you very much. See you tomorrow.

(Thereupon, evening recess was taken at 4:35 p.m.)

* * *

CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Commission (Volume I) 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 September 24th, 1996.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998