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 II)
September 19th, 1996
Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission, WILLIAM J. LEMAY, Chairman, on Thursday, September 19th, 1996 (Volume II), 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 19th, 1996 (Volume II)
Commission Hearing
CASE NOS. 11,525 and 11,526 (Consolidated)

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E X H I B I T S

Conoco

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E X H I B I T S (Continued)

Conoco

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Conoco

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E X H I B I T S (Continued)

Conoco

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WHEREUPON, the following proceedings were had at 8:35 a.m.:

CHAIRMAN LEMAY: Good morning. This is the Oil Conservation Commission in the second day of hearings on consolidated Cases Number 11,525 and 11,526.

I think, Mr. Carr, yesterday you were giving your presentation of witnesses and --

MR. CARR: -- and we have concluded --

CHAIRMAN LEMAY: -- do you have some addition to --

MR. CARR: Our direct case has been concluded.

CHAIRMAN LEMAY: Your case has been concluded?

MR. CARR: Yes, sir. Thank you.

CHAIRMAN LEMAY: We shall turn the podium over to Mr. Kellahin. Mr. Kellahin, it's your show.

CHAIRMAN LEMAY: May it please the Commission, I'll present two witnesses this morning.

The first witness is Mr. Bill Hardie. He's already taken the witness stand. Mr. Hardie is a petroleum geologist. He resides in Midland, Texas.

Mr. Hardie and Mr. Beamer and I have agreed among ourselves that our presentation will be such that Mr. Hardie will make his geologic presentation on North Dagger Draw, and then before he's excused he'll go into his presentation on South Dagger Draw, and that way we complete a full presentation with this single witness before we move into the engineering witness.

And with Mr. Beamer we'll do the same thing. We'll talk about North Dagger Draw, and then when I finish my direct with him, he and I will go into South Dagger Draw.

The first sets of exhibits that I'm handing you are the Conoco exhibits, the engineering and geologic exhibits for North Dagger Draw.

WILLIAM HARDIE,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. My name is William Hardie. I'm a geologist with Conoco, Inc., for the southeast New Mexico area.

Q. Mr. Hardie, you're going to have to keep the volume of your voice up. Where I'm sitting, there's the hum of this wonderful heater that is spewing forth heat this morning, and so you'll have to speak above it. We've stopped the drip, apparently, and so Florene is not going to be drenched.

Give us a short summary of your educational background and employment experience, and with particular emphasis on your involvement with the Dagger Draw production.

A. I have a bachelor of science degree from Baylor University, a master of science degree in geology from Baylor University as well. I graduated in 1990.

And at that time I started working for Conoco in Midland and have been assigned the southeast New Mexico area since that time, so it's been about six years that I've worked in southeast New Mexico. And I've worked Dagger Draw for that length of time as well, amongst the other fields that Conoco operates in Eddy and Lea Counties.

Q. Have you qualified as an expert geologist in past hearings before the Division that have dealt with issues in Dagger Draw?

A. Yes, I have.

Q. Have you made a study and investigation of the geologic factors involved not only in North Dagger Draw but in South Dagger Draw?

A. Yes, I have.

Q. The maps that we're about to see were not generated exclusively for the hearing today, were they, sir?

A. These are standard maps that we have on file and update periodically.

Q. So this represents work product that you've been involved in for the last five or six years with regards to Conoco's geologic analysis of Dagger Draw?

A. That is correct. I have added items on the maps for the specific purpose of this hearing, but the geological information is something we compile and update on a regular basis.

Q. When Conoco drills Dagger Draw wells, are you involved in that process as their geologist?

A. Yes, I am.

Q. And when Conoco has a working interest in other wells, drilled by operators other than Conoco, is that geologic information eventually assimilated by you and integrated into your work product?

A. Yes, it is.

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

MR. CARR: No objection.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) Mr. Hardie, let me have you, sir, to help us understand your analysis of the geology. Look first at North Dagger Draw, and let me have you begin by identifying what we've marked as Conoco Exhibit Number 1.

A. Exhibit 1 is an isopach of the net dolomite across North Dagger Draw. It's quite similar to the map presented yesterday by Mr. -- by Brent --

Q. Yeah.

A. -- May.

Q. May.

A. There's very little difference, actually, in the geological interpretations between Brent and myself, and I think that will become apparent as we progress.

Q. Tell us the color code so we understand what we're seeing.

A. Okay, we're looking at -- First of all, the contours themselves are color-coded such that the darker blues represent thinner sections of the dolomite, and then they progress into the colors, yellow colors, as they get thicker and thicker, so that the outer edges of the dolomite fairway are the zero line, and it thickens towards its axis, approaching thicknesses over 350 feet thick.

Q. Help me understand what you mean when you talk about the dolomite thickness map.

A. Simply what we have done is to take the Upper Pennsylvanian interval and count up the total feet of dolomite within that interval. That footage is what we map.

As Brent explained yesterday, the reservoir at

Dagger Draw is dolomite. If you don't have dolomite, you don't have reservoir. So by mapping the dolomite, you're mapping the reservoir. It's very convenient, one of the unique features of this field.

Q. What are the other colored lines represented on the display?

A. The red bold outline is the North Dagger Draw Pool boundary as of the last hearing. You can see there are some well symbols lying outside of that boundary. The pool is constantly growing, so I'm quite certain that this needs to be updated.

The solid yellow line inside that is the -- is a boundary around the proration units which are currently, or at the time of the last hearing were in violation of the allowable and had accumulated illegal oil.

I've also shown on the cross-section through dashed red lines three -- on the map, three of the cross-sections that we'll be showing in the later exhibits.

Q. One modification in this Exhibit 1 from the last hearing is, now you've included the northwest quarter of Section 33 as part of the violation area, including that spacing unit?

A. That is correct. We did not recognize that as being in violation at the last hearing. It was and it still is. So that is --

Q. And who's the operator of that spacing unit?
A. Mewbourne is the operator of that spacing unit.
Q. At the last hearing, in May of 1996, was all the production information for the wells producing within the violation area available to the parties at that hearing?
A. There were a lot of wells drilled early this year around the violation area. The information was not available to me at the time of the last hearing. I have since gathered that data, the production data, the geological data, and incorporated it and revised the maps that you're looking at now from the last hearing.
Q. When we get around to talking about the volumes of production from spacing units in the violation area, those volumes are going to be different than the volumes we discussed in May, are they not, Mr. Hardie?
A. They will be different. They have been updated.
Q. All right. And those numbers now, to the best of your knowledge, include all production volumes attributable to those spacing units that account for the overproduction?
A. That is correct.
Q. Let's look at the distribution of reservoir thickness on this map, in relation to the Conoco-operated properties in Section 32, as well as 31, and how they are similar or different from the dolomite thickness in the violation area.

A. One of the reasons I've included this map as an exhibit is to compare first of all just reservoir thickness in the violation area and other parts of the field. And when you take a quick look at this, there is very little difference. The violation area includes thick portions, it includes thin portions.

I would note that in Section 28 you can see a prominent re-entrant of the blue colors, indicating that the total dolomite thickness is becoming very thin in that area. That happens to be one of the worst violating proration units.

So there's not a good relationship between thickness and the ability of a well or the operator to violate the allowable.

Q. There was an statement made by one of the Yates witnesses that I think reversed what I believe is Conoco's position about what you believe to be the risk to Conoco in terms of thickness in relation to the thickness in the violation area.

I believe that the statement yesterday is that you were in a thicker portion of the dolomite. And if that was said, I would like to give you an opportunity to explain to us your interpretation of the relationship of the thickness and how that affects your correlative rights as you relate to the overproduced spacing units.

A. Of course correlative rights involves several issues, one of which would be the thickness of the reservoir. The thinner the reservoir, the higher the rate in that thin reservoir, the more chances there are for violating correlative rights. There's not as much pay in a thin zone as there is in a thick zone.

That's one of the attributes that we will examine today as we move through these exhibits and look at the various geological parameters and how they relate to the violating area versus the non-violating area.

Q. All right, sir. Let's set this aside, then, and have you turn your attention to Conoco Exhibit Number 2. Mr. Hardie would you identify Exhibit Number 2 for us?

A. Exhibit Number 2 is a structure map on the top of the upper Pennsylvanian dolomite. Again, this is very similar to the map that was presented yesterday by Mr. May. So what we're looking at with this map is an elevation map on the top of the reservoir.

Again, some of the components that I've included on this exhibit, the outline of the pool boundary as of the last hearing, is shown in the heavy blue line. The violation area is shown within there as a thinner green line. Solid yellow shading on this map indicates that that acreage is operated by Conoco. Cross-hatched yellow shading on this map indicates that Conoco has interest in that proration unit but does not operate.

So as you can see, we do have an interest in many of the proration units which have currently produced illegal amounts of oil. Most of those -- in fact, I believe all of them -- are operated by Yates. Conoco has a partial working interest in them.

Q. With regards to the Yates-operated spacing units in the violation area for which Conoco has a working interest, to your knowledge does Yates contact Conoco and ask you what levels you would like to have these wells produced at?

A. That is never discussed amongst operators. The only discussions we may or may not have between operators is the viability of drilling a project. Is there enough reservoir there to justify the drill? If we have a concern, we may approach the operator.

In this case, we're sitting in the middle of the reservoir, so there are no concerns about missing or hitting unviable pay sections.

When we are approached with an AFE to participate in a well, we have two options. We can participate and join in, or we can nonconsent or farm out our interest. And because of the productivity of the wells in this area and the amount of money they can generate, even within the bounds of the law, Conoco participates in these types of proposals.

We do not involve ourselves in the day-to-day operations of our offset partners.

Q. With regards to the Conoco-operated spacing units in Dagger Draw, Mr. Fant made a point yesterday with Exhibit 7 that he shaded in your spacing units a darker color if at any point in the producing life of that spacing unit he found a point in time where that spacing unit was overproduced.

Are you familiar with the production history on your spacing units in terms of over- and underproduction?

A. I'm familiar with the production history on them. I haven't examined them closely to see if there were small instances of overproduction. I can assure you that it is a Conoco corporate policy to remain within the guidelines. If perhaps a well exceeded an allowable, it did not happen with my knowledge; and if it had, I would have done something about it.

I realize there are in the records instances where we momentarily exceeded the allowable, but we never at any point accumulated anything significant in terms of illegal oil. In fact, nothing in terms of -- even close to the amount of violations that have occurred in the past.

Q. Mr. Hardie, I think there's next to you, over on the right, a copy of the Examiner Order. It's underneath that first display. Yes, sir. Is that a copy of the Order?

A. Yes, it is.

A. If you'll turn to page 8 with me, Mr. Fant, and I had a discussion yesterday on the geologic conclusions the Examiner had reached in that Order, and he brought to our attention that in that first finding he had a disagreement with the finding and particularly with regard to the conclusion about good vertical permeability.

What is your position on behalf of Conoco with regards to that issue?

A. We -- Conoco has extracted, I believe, two if not three cores from this reservoir and we have tested them extensively. Those cores show good vertical permeability.

Typically, we don't test zone barriers, and there are zone barriers within this reservoir, and those barriers are mappable and identifiable and we treat them as such. But within a zone, we have good indication that there is good vertical communication. And in certain parts of the field, even the barriers -- we have good indications that they are no longer intact, no longer capable of isolating zones; they experience pressure depletion from adjacent zones.

So depending upon where you are in the field, there can be very good vertical communication, but there are zone isolators.

Q. With regards to the geologic conclusions that are inherent in Finding 9 E, what is your position? That finding says, There are consistent hydraulic connections and good pressure communication across the pool.

A. It has been our experience, sometimes very painful, to prove up that statement E. We --

Q. Why do you say painful?

A. Painful because we've drilled wells that we thought would have good pressure, and they had dismally low pressure, and the only way they could have had low pressure was by drainage from offset production, either laterally or vertically. So there's clear indications that this is the case.

There are likewise some indications that there are some permeability barriers within the reservoir. You can encounter higher pressures, particularly as you step out into newer portions of the reservoir and avoid infill development. That statement is true.

Q. We touched on numerous issues in a technical sense yesterday, and I'm going to ask you to help us frame, from your perspective, those issues of importance for you that you want to share with the Commission.

Before we do that, Mr. Hardie, I'd like you to give me a general overview of your geologic conclusions with regards to the characterization of the reservoir between North Dagger Draw and South Dagger Draw and the distribution of those fluids. Give us a short course on Dagger Draw.

A. This is a complicated reservoir to give a short course description in, but I'll do my best.

There are several theories to try to explain the distribution of fluids from North to South Dagger Draw and into Indian Basin, one of which is the hydrodynamic theory, originally proposed by Hugh Frenzel, I believe, back in the 1960s when he was developing for his company the Indian Basin field, and he recognized differing gas-water contacts within that field. That theory can still be applied as we move to the north, into South Dagger Draw and North Dagger Draw.

It does have some problems with it. It doesn't fit perfectly.

I have in the past proposed alternative theories as to the distribution of fluids in this reservoir, namely having to do with the way the fluids migrated into the reservoir upon them being filled.

The reservoir itself, this 40-mile-long reservoir that we have broken up into three or four different pools, has been tilted, and that tilting to a large degree occurred after it was deposited, so that we're looking at a tilted reservoir. It's faulted at its updip end, at Indian Basin, creating the ultimate trap and seal.

The reservoir was filled from a downdip direction by gas and oil. The gas and oil passed through a series of compartments that Brent explained to us very well yesterday.

These compartments are not perfect seals. They act as almost semi-permeable membranes. They're extremely permeable to gas. The gas rushed on through this reservoir and went up to Indian Basin.

They're less permeable to other fluids; they're less permeable to oil. So as oil came and began entering from a downdip direction and an updip direction, it became progressively trapped as it entered each successive compartment, such that by the time we get to Indian Basin, virtually all of the oil has been trapped.

So you have, in a sense, a tilted oil-water contact across this field that can be explained just by the way the fluids migrated into place. That's another theory. There's several.

The bottom line is, the fluid distributions are not what you would expect in a completely and continuous and connected 40-mile-long reservoir.

Q. Is it possible to apply your science and experience to North Dagger Draw and determine the size and the shape of these compartments in the reservoir?

A. You can. And although you can determine the size and the shape of them geologically in some instances -- and I'll show you some instances -- in most cases geology doesn't help much with the identification of compartments. The most important parameters are evaluation of production data. And I think Yates has confirmed this as well. They concur with this.

Conoco has in the past identified some very large compartments, and there can be no other explanation for the pressure data we have seen than to recognize that there are extremely large compartments, large compartments which can be drained very effectively, very quickly, with single wells. And we have examples of this.

Before I get into much more technical data, I would like to address, if I could --

Q. Sure, I'd like you to frame the issues as you see them for part of your presentation.

A. -- some issues that Conoco and Yates have dealt with in the past. Many of these issues we agree on, many of the issues we disagree on.

I think it's somewhat unfortunate that our disagreements always end up in this public body, because for the most part we agree on the geological and reservoir parameters in this field.

I have a tremendous amount of respect for Yates' technical staff. Yates hires the best people in the business, and I think you can tell that.

I think they would also recognize my right and ability to take the same data set and arrive at different conclusions, because at times we do that.

But there are other instances where we're in complete agreement, and I want to get those out in the open, because I was under the impression in some of yesterday's testimony that particularly Mr. Fant thinks we disagree on some issues, and we don't. I'd like to go over a couple of those, if I could, here, the first of which would be the issue of 40-acre spacing.

I got the impression from Mr. Fant's testimony that he thought Conoco was in favor of somehow restricting the development of this pool on 40-acre spacing, and that's simply not the case. We're very much in favor of the right of an operator to develop his acreage on 40-acre spacing. We have testified to that fact. They brought that testimony out. We still stand behind that.

Does that mean we think that this reservoir should be developed everywhere, at all locations, on 40-acre spacing? Certainly not. There are portions of this reservoir which need 40-acre spacing in order to recover an efficient amount of -- an equitable amount of the reserves.

Mr. Fant has brought out some of those examples.

There are other portions of this reservoir which do not need four wells per proration unit, they need one, and we've experienced those in the past.

I gained the impression from Mr. Fant that he thought this was the first time in the history of this reservoir that we have been able to maintain high sustained rates from it, and that's certainly not the case. It may perhaps be the first time Yates has been able to maintain high sustained rates from this reservoir, but it's certainly not the first time Conoco has been able to. We could have in the past, and can today in some cases, exceed the allowable. We don't. And that's an important conclusion to draw.

When Mr. Fant looks back through the history and he sees that Conoco has not accumulated significant volumes of illegal oil, he assumes that we couldn't. And it's not that we couldn't; it's that we didn't.

And I'd like to show you a couple of examples where we didn't. And this map is probably a good one to do that. This is Exhibit Number 2, the structure map across North Dagger Draw.

I'll draw your attention to Section 36 of Township 19 South, 24 East. The lower half of the section is operated by Conoco.

This is one of those incredibly prolific pockets in the reservoir. Conoco, in the late Eighties, perhaps early Nineties, drilled its D State Number 2 in the southwest of the southwest quarter. It was the only well in that proration unit at the time. It was a fantastic well, capable of production rates just at the allowable.

Conoco produced this well at rates between 550 and 600 barrels of oil per day for approximately three years, draining a very large area. We didn't know that we were draining a large area at the time. There weren't many wells in the field at the time.

We could have drilled another well in the proration unit because we were about a hundred barrels shy of the allowable. We chose not to because we knew that if we did, we'd have to restrict it. Operationally, that's a nightmare. Yates has testified to that.

The well produced for a period of about three years and literally crashed and burned. It went from rates of 550 over a period of months to rates of 50 barrels a day, 40; on a good day sometimes we might get 60.

At that point Conoco decided to drill an offset to it. We had plenty of allowable left. We decided, because we knew this well had made tremendous amounts of reserves, to get as far away from it as we possibly could. I proposed the D State Number 4, on the opposite corner of the proration unit. The D State 4, to me, was a great location.

We had tried to recomplete the D State 1, which is just east of it, from the Morrow into the Cisco. Mechanically, that was not terribly successful, so it hadn't produced many reserves. We tried to twin that well with the D State 3. Mechanically, that was a dismal failure. The pump, the SP we put in that well, became irretrievably stuck. The Cisco was no longer available to us.

We had a large area. The only other offset was Yates' State "CO" Number 4. Large area to drain. I'm excited about this well, I propose it hoping to see something like we saw in D State 2. It was drilled. Mudloggers told me that the pay section in that zone looked just like the D State 2. I was even more excited.

We completed the well, perforated the same intervals that produce elsewhere. The well produced approximately 100 barrels a day. I called the production office to find out what was wrong. What's wrong with my well that should be so great? They measured bottomhole pressure at approximately 400 pounds. That location had been drained by the D State Number 2 and offsetting production.

Now, if we had developed this location at a time when we had, let's say, a 4000-barrel-a-day allowable, Conoco could have gone in here, drilled on four locations, and pulled the same number of reserves out of the ground with four wells -- Who knows? If we got there before our neighbors we might have even got some of their reserves at the same time. The ultimate result of that would have been that we would have gotten the same amount of reserves, perhaps some of our neighbors', and drilled four wells instead of the necessary one. We drilled two, we wasted some money. The second well in that unit is marginal at best. That's one example.

So the question that we're asking ourselves today is, Is there some rate at which it is easy to violate the correlative rights of the offset operators? Is there some limit that we can put on this reservoir?

If the answer is no -- and I think that's what Yates is proposing when they suggest that the highest-producing oil well be the limit -- if the answer is no, then we need not regulate this pool; it's nonprorated. Let's turn out the lights in the Artesia office and save the taxpayers some money.

I don't think that should happen, and I don't think anybody in here does.

This should be a prorated pool. There has to be some balance in terms of rate which protects the correlative rights of the offset operators and at the same time offers an operator an equitable chance to recover his fair share of the reserves.

It may be that that rate is such that you have to constrain a well and create some waste. That may occur. But it's got to be balanced against the rights of the offset operator. I would suggest to you that a rate of 4000 barrels a day does not accomplish that.

And as we testified to when we first asked for the allowable increase, a rate of 700 barrels a day does accomplish that.

Certainly there are interference examples at that allowable rate. We've -- Conoco has recognized these in the past. But that is a balance between protection of offset rights and the ability to pull your proper amount of reserves out of the reservoir.

I'd like to talk a little bit about interference and, if I could, I'd like to use some of Mr. Fant's examples. I am not a reservoir engineer, but I have worked this reservoir for six years and I'm pretty familiar with some of the examples that he brought forth. He had a different explanation for them. I would contend that some of his examples were nothing other than interference.

I'll begin with his Exhibit Number 24, in which he described their brand-newly drilled Polo Number 6 well.

The Polo 6 is the first Cisco well drilled in the southeast corner of Section 10, and as you can see it's outside of my pool boundary, over on the right-hand side of your map. It's a brand-new well. The pool boundary probably now extends into the southeast corner of Section 10.

This well came on at over the allowable rate, and Yates shut it in, in order to not accrue any other illegal oil. When they brought this well back on line, it came in at a lower rate than it did when they shut it in.

If you take a straight edge and run it through the oil rate on this diagram, you'll find out that it matches up perfectly, as if this well had been producing all along. I would contend that this well wasn't producing all along, but the reservoir was being produced all along. Those reserves weren't coming out of this well; they were coming out of the adjacent wells. This well is offset on three sides.

Conoco has seen this kind of example on countless times, and we attribute it to interference between wellbores. I would suggest that Mr. Fant needs to add perhaps a dashed line on his interference diagram, Exhibit 14. A difference of opinion, same data. He attributes it to one thing, I attribute it to another.

Q. Let me ask you to amplify this point, Mr. Hardie.

Mr. Fant's conclusion, based on the Polo example, is that he was experiencing wellbore damage?

A. That's right.

Q. This was his sole example in the pool of that phenomenon, for which then he attributed he could not restrict these wells in some kind of cycling procedure.

Have you had an experience like this, with just the opposite results, where you shut a well in over time and yet are able to return it to production successfully?

A. That has happened in the past, and if I can bring up an example, particularly as we get later on in some of my exhibits -- I'd like to bring up one more example of interference.

Mr. Fant presented in his Exhibit 15 a rate-versus-cum diagram to show that as they drilled progressive wells in a proration unit, they encountered new reserves. And they in fact did, depending upon how you interpret this. You might disagree that they did not. I would suggest that they did encounter new reserves.

But with each successive well they encountered less reserves. In my mind, that's interference. That is not terribly significant interference, but it is interference. You've cut the cums of these successive wells, sometimes in half, sometimes much less, depending on how you interpret it

I would suggest that Mr. Fant needs to include on his interference diagram a couple more dashed lines in the southwest corner of Section 29.

My point here is, again, we're looking at data sets and drawing different conclusions based on them. It's clear that Mr. Fant has a subjective interpretation about interference. My interpretation of interference is perhaps a lot more liberal. I would have a lot more lines on here. And I would question his statement that only five percent of the cases result in interference. I think it's much, much more prevalent in this reservoir than that.

Q. Is the geologic data available to you consistent with your conclusion about interference?

A. Yes, it is. And again a lot of this is -- I'll try to highlight this as we progress through some of the later exhibits.

I want to make one more point on yesterday's testimony, and then perhaps we can get through with the rest of what I have brought today, and that has to do with Mr. Fant's Exhibit Number 10, I believe it was, in which he examined the oil rate versus oil cut and found a positive relationship fieldwide. He looked at every well in the field and compared the rate of the oil being produced with the oil cut and found that as the rate lowered, the cut lowered.

This is certainly nothing new to Conoco. We've recognized this countless times. We attribute it to something entirely different, other than the pumped-off status of the well.

I contend that all those wells are pumped off. We don't tend to produce wells in a non-pumped-off condition, and I think Mr. Fant did confirm that yesterday at some point.

That phenomenon is what we attribute to -- what we call a weak water influx. As wells in Dagger Draw decline, particularly in the later part of their stage, when they're not making much oil, you begin to see a slight increase in water cut. You can see this on plots. You don't see it on the big wells; the increase is too small. But on the older wells, if you look at them, there's a slight increase in water cut, a decrease in oil cut. We attribute this to a weak water influx, recognizable only when the well is down low in its life.

And it brings up an interesting issue in my mind. What if you are not producing -- you have a great well, it's capable of rates in excess of 1000 barrels a day. You are required to constrain it so that in fact it does produce a higher water cut, because you're producing it with a high volume of fluid in the wellbore, very inefficient method of production. It does increase water cut, I'll admit, we've testified to that.

What if you do that initially? How is that going to affect, in the later life of that well, that slight increase you get in water cut? Is that going to decrease it so that ultimately you produce the same amount of oil and water over the life of the well; you just get it at a different stage in the life of the well?

It's an interesting issue. We can't prove it or disprove it unless we examine one of these high-rate wells that is allowed to produce to depletion. But I would bring that up as a possibility. We're talking about the same volume of oil and water; it's just a matter of when you get it.

And that's the last issue I'd like to bring up, is that we fully and completely concur with Mr. Fant's notion that wells that have high fluid volumes in them produce at a higher water cut. We've testified to that in the past, and we haven't changed our position on that. The most effective way of producing these wells is to pump them off.

I'm done with that. Let's, if we can, move on to the following exhibits.

Q. Mr. Hardie, let's turn, then, to what we have as Conoco Exhibit Number 3. Let's keep out one of these locator maps, either Exhibit 1 or 2, which will help us find the line of cross-section as we look at the cross-section displays.

The first one we have is the A-A'. Show us the orientation of the cross-section on perhaps Exhibit 2, and then let's talk about what we're seeing in the display.

A. If you'll look on Exhibit 2, please find cross-section A-A', and you'll -- This is a cross-section that I included in the last hearing, and I include it again with a few changes. I've added overproduction, illegal oil attributed to the proration units above each of the wells in the cross-section.

This cross-section was simply designed to show the stratigraphic relationships between the proration units which are violating the allowable and those which are in compliance. It begins with the Patriot 2 and 3, in an area that is in compliance, over on the left-hand side of your cross-section.

This is pretty typical. As we move from the heart of the field, the older part of Dagger Draw, you can see, and we move out to the flank, off to the right of your cross-section, we begin to encounter thinner pay zones. In Mr. Fant's term, we encounter dolomite stringers.

If you'll examine the wells in the middle of this cross-section which are completed, virtually all of them are completed in that upper dolomite stringer. That is a relatively thin interval. It varies, around 50 feet thick to 60 feet thick.

Please look at the Yates Number 3 Tackitt "AOT". Look at the completed pay interval in that well. You've got about, I'm guessing, 60 feet of pay in the upper stringer. That well has -- and the wells in its proration unit, have produced 239,000 -- over -- almost 240,000 barrels of illegal oil as of today -- or as of July, which was the latest available data.

When you look at the thin pay interval available to these wells, that's one of the parameters that we look at to determine if we're affecting the offset correlative rights of adjacent operators. This is a relatively thin pay interval, and it's having tremendous amounts of oil pulled out of it. So we're examining thickness, that's all.

A couple of other items on this cross-section I need to explain as we move on, and I got a little ahead of myself.

The color code. Brown is lithologically indicating shale. Blue indicates limestone, non-pay, tight carbonate. Purple indicates dolomite, pay, potential pay.

If you'll look on the cross-section, there's a dashed line running down the middle of it. That is at a datum of minus 4300 feet. That approximates the oil-water contact, and Mr. May referred to this yesterday, that that's only approximate. And using the word "contact" is somewhat of an oxymoron; it's more of a gradation. You probably don't encounter a very distinct contact.

As you perforate lower and lower in the section you encounter higher and higher water cuts. It is very unusual for an operator to perforate below minus 4300 feet. It does happen, but typically those wells will have high water cuts. It is not an economically attractive thing to do, shooting below that line.

So anything above that line that is colored purple as a dolomite is potential pay. So you can see what is available to these wells, and it's not much in terms of thickness.

I suppose I'm ready to move on to the next cross-section.

Q. All right, sir, let's do that. It's Exhibit 4, and it's going to be the B-B' cross-section?

A. That's correct. Again, if you'll refer to Exhibit 2, you can locate on the map cross-section B-B. Again, you can note that it passes through some of the worst violation areas and into Conoco-operated acreage in Section 32.

A point was made yesterday by Mr. May in which he -- I think he perhaps misunderstood something I had said in the previous hearing. He seemed to think that I thought that Conoco's Number 1 Savannah on this cross-section was being drained by the Yates Number 3 State K well. I don't believe that. And if I gave that impression that I did, I apologize. That well is probably too far away to affect it.

And that's one of the illusions of this cross-section, is that it's a long thing, but it's been contracted to get it all on a small piece of paper. These wells are spaced quite a ways apart. In fact, most of them are 80 acres apart, across this violation area.

And that's another point I'd like to make, is that the violation area is not developed on 40s for the most part. The really good wells are developed on 80s. That's one of the reasons I contend they haven't seen much decline, is that they're draining very large areas.

And again, when you look, stratigraphically, at the intervals they're completed in, the limestone stringers, if you will, are relatively thin. They do have tremendous porosity and permeability in them. But in my mind the reason they're making high sustained rates is because they're draining large areas across thin intervals.

I contend that if Yates were to allow the wells in Section 28 to produce to depletion, if they were to go in and offset those wells, they would have a similar experience to what I had in the D State area when I drilled the D State Number 4 and found 450 pounds of bottomhole pressure in the producing zone. I contend these wells drain large areas. The compartment that they are draining has high porosity, high permeability. It is easily drained by a few number of wells and quickly drained by a few number of wells.

Yes, you can put more wells in there and pull those reserves out faster, but in doing that you violate the correlative rights of your offset operators, because you're draining such a large area.

I'm done with Exhibit 4.

Q. All right, let's turn to Exhibit 5, then, Mr. Hardie. It's the C-C' cross-section, and you're comparing wells that include Conoco-operated wells, the Joyce Federal well?

A. That is correct. This is one exhibit that was not included in the last hearing. Again, it just further illustrates the points I've been making.

In this case we're looking, and on the left-hand side of the cross-section, in the older part of the producing reservoir, you can see the pay thickness that is available to the wells in the older part of the field. They don't have the porosity of these thin stringers that are being overproduced nowadays.

Then, as you move across into the middle of the section, you enter a Yates-operated proration unit. It has four wells and has accumulated some 56,000 barrels of illegal oil as of 7-96.

You move into Conoco's acreage on the other side of Section 32, with our Joyce Federal Number 1, and you can see the dramatic thinning that occurs as we approach the edge of the reservoir.

Now, from a reservoir-thickness standpoint, Conoco doesn't have nearly the amount of reserves to play with that, say, Yates does as they encroach the thicker part of the reservoir. But it is possible to calculate volumetrically how much Conoco should recover in these thin zones, based on the porosity, the pay thickness, the height above our oil-water contact. And that is what I have included as part of my next exhibit, is an examination, volumetrically, of what these wells should recover and a comparison with what they are recovering.

Q. At the last hearing in May, you had the belief and expectation that the Conoco spacing units adjacent to the violation area were being exposed to drainage, and yet Mr. Carr questioned you at length about your ability to quantify, or at least give us some ratios about that drainage component, and you had not yet done that work?

A. I had not. That was one of the reasons that

Conoco requested a continuance of the last hearing. We had exactly a week and a half to prepare for that hearing, between the time we were notified and the time the hearing occurred.

We requested a continuance, because we wanted to do a fairly comprehensive study of volumetrically what this area was capable of producing. We didn't have time to do that, and we did not present any such information at that last hearing. We have prepared it now and are prepared to present it.

Q. All right. Exhibit 6 is one I spoke from yesterday. It's -- A large copy of it is on the display board, Mr. Hardie. Identify for the record what we have as Conoco Exhibit 6.

A. Exhibit 6 is simply an outline map of the amount of illegal oil that has been accumulated in proration units. The outline itself is similar to the exhibit we presented at the first hearing. There have been some changes that have occurred.

In each proration unit outlined in red, there is a reference number, so that we can easily reference each of these proration units. If you'll look at the Unit Number 4, Yates operated, you'll see the value of 26,912 barrels of oil in parentheses. That means that they are now that far under the allowable. That unit was some nearly 12,000 barrels overproduced at the last hearing, or as of the last available data we had at the last hearing.

You might say that unit has crashed and burned. It has experienced very steep declines. And I think that type of behavior is what we're going to see as these wells finally drain the compartments that they are producing from.

Another addition that has occurred since the last hearing was the reference number 14, the spacing unit operated by Mewbourne. We did not realize at that time that Mewbourne had exceeded the allowables, and we've included that for this display.

Q. You have conducted your volumetric analysis of the violation area and the adjacent property in connection with a reservoir engineer, Mr. Bob Beamer, did you not?

A. That is correct.

Q. So the engineering aspects of those calculations and that process have been completed by Mr. Beamer?

A. Yes, Mr. Beamer and I worked closely on that.

Q. All right. And you're going to present, then, as the presenter, the combined work product of you and Mr. Beamer to illustrate for the Commission your attempt to quantify the magnitude of drainage and violation of correlative rights that have occurred in this area; is that not true?

A. That is correct.

Q. All right, sir. Before we do that, Mr. Hardie, I'd like to have your comments with regards to a particular statement made by the Commission when they issued the stay of the Examiner Order. It's the Stay Order issued August 16th. There's a statement in the last finding in this Order, in 6, and I'll give you a copy of it.

The Chairman concludes that the Commission will hear this matter on the 18th of September, because those overproduced wells in the upper Pennsylvanian reservoir in South Dagger Draw and North Dagger Draw have ample remaining producing history to be brought into balance with Division allowables if the Commission affirms the subject Order.

Are you with me?

A. Yes.

Q. All right. What if any concerns does Conoco have about its ability to be treated fairly with regards to withdrawals in the pool, in relation to the magnitude of the illegal oil produced?

A. In terms of what we've been able to look at volumetrically, and in terms of what our offsetting wells are doing, they are experiencing very steep declines. It's easy to see that the damage has been done. It's over. You don't get the pressure back when the oil and water and gas has been removed in an illegal fashion. It cannot be replaced. And once that's gone, the ability to produce a reservoir at that old pressure is gone as well. We can't recover that.

And while we recognize that we cannot recover, perhaps, some of the damage that has been done, we can emphasize the need for strict enforcement of the allowable rules, and we can make our case for keeping the pool rules as they are and not increasing the ability of operators to violate the correlative rights of others.

Q. Let's look at your presentation, Mr. Hardie. Let's turn first of all to Exhibit Number 7 and have you identify and describe this display.

A. Exhibit Number 7 is a standard volumetrics-type map. It's ϕh. It's the primary input for determining the volumetrics in an area.

The way we constructed this map was to enter in the various well logs digitally, into a database. Those porosity logs were then evaluated, a neutron density crossplot value was obtained from them, the best determination of porosity in that log, and a 2-percent cutoff was applied to those curves so that we could determine the amount of effective pay available to each wellbore.

The interval that we evaluated for the purposes of this map were from the top of the dolomite reservoir to that minus-4300-foot interval, below which we know it's very difficult to make an economic well. So we've evaluated that interval. We've looked at the porosities, we've applied a 2-percent cutoff and determined how much pay can effectively contribute, of fluid, oil, gas, water. That's what you're looking at here, is a map of pore volumes.

To complete the volumetric exercise, you really need to look at Exhibit Number 8.

Q. All right, let me ask you about how the contours were put on Exhibit 7, before we leave it. Those were hand-drawn contours, but it was computer-assisted, was it not?

A. The values from the well logs were derived from the computer. The computer was allowed to make the cutoff. That way there can be no human input allowing William Hardie to pick the cutoff himself and then, with human error and discrepancies built in, pick the amount of pay available to produce a well. I am left out of this picture when it comes to picking the pay; the computer does that. Those values were then plotted on the map and Mr. Hardie hand-contoured that map, so that you can see before you the influences that my interpretation had on those values.

The map was then -- hand-contoured map was then digitized. And that digitized map was then evaluated, again with a computer program, as to the volumetric -- the amount of volume, pore volume, available under each proration unit. And the grid that was used to determine the volume, the pore volume, under each proration unit, is shown in the heavy red lines, and it's each 160-acre proration unit.

So that the final outcome of this process is to determine the total pore volume available under each proration unit. That's what this map has done. Those values are what exist on Exhibit Number 8.

Q. All right, let's look, then, at Exhibit 8.

A. You take a --

Q. We'll take a look at these comparisons in a minute, but go ahead and show us how the map is constructed.

A. You take a pore volume. That doesn't have anything to say about what may exist within that pore volume, and therein lies a little bit of debate in Dagger Draw. What is the water saturation?

Dagger Draw's aquifer is nearly fresh, and as the geologists and engineers among us know, fresh water has a very high resistivity. One of the methods that we use for calculating water saturation is the Archie's equation. And when high resistivities are encountered, Archie's equation doesn't work very well. And it doesn't work in Dagger Draw. The resistivities literally are at the limit of the tools that are logging them, they are so high. We have to obtain other methods for determining water saturation.

Conoco has used core data to evaluate water saturations across the field. We have taken cores that we've extracted, done capillary-pressure tests on them. With a capillary-pressure test you can develop a graph which tells you theoretically what the water saturation should be at a certain height above the known oil-water contact.

Our oil-water contact, or that transition, is somewhere around 4300 feet. Most of the reservoir here is at an elevation of minus 4150. So we've got about 150 feet of maximum height above the oil-water contact.

Those are the types of values that we use to come up with an average water saturation. We used 40 percent. You can alter that either way, up or down, but that's the value that was attributed to the entire map, because the entire map is at about the same elevation. It varies 50 to 60 feet from here to there.

The other parameter that is included is a recovery factor. This is a gas solution drive with a weak water influx.

Typical recovery factors, as was testified by Mr.

Fant, in these types of reservoirs are usually from 10 to 15 percent. We use 20 percent, because this reservoir has very large vugs in it, so we extended that a little bit. So that's another volume contributor -- or reducer, actually.

So we take that 20-percent recovery factor, we take a water saturation of 40 percent, and we take a factor that is used to calculate the expandability of various fluids in the reservoir that we obtain by measuring those, and apply those to the volumetrics, and it tells us what we should recover from each proration unit.

That number is listed on Exhibit 8 for each proration unit as the upper number. It was intended to be green, but it looks kind of blue, but it's always the upper number.

So that for example, in the reference unit number 30, the Mewbourne-operated unit in the southwest corner of Section -- I'm sorry, the northwest corner of Section 33, that unit, according to the volumetric calculations, should have recovered 172,000 barrels of oil.

Q. Now, the numbers of these tracts are obviously different from the numbering system used to identify the violation spacing units?

A. That is correct, and that wasn't a very good idea on my part, so...

COMMISSIONER WEISS: I'm confused, I don't know where you're talking about.

THE WITNESS: Okay, I'm talking about reference unit number 30. It's got a number in the upper left-hand corner, blue number. That's a reference number. If we look in that unit, the green number, the uppermost number, is the amount of oil reserves that should be recovered from that unit.

Q. (By Mr. Kellahin) It's 172,000 barrels of oil?

A. 172,000 barrels of oil. It's in thousands of barrels of oil.

Q. All right, let me stop you right there, sir.

A. Sure.

Q. By using a 20-percent recovery factor, these calculations credit that spacing unit with more recoverable oil volumetrically than you would have available if you had used a smaller recovery percentage?

A. Sure.

Q. Okay. You're attempting to determine what is the correlative rights, the opportunity to produce your share of reserves in a spacing unit, and to quantify the volume of recoverable oil within that spacing unit, right?

A. Uh-huh, that's correct.

Q. That's the first step.

The next step, or the second number down, is what these wells ultimately will produce within those spacing units?

A. That is correct. The next number down is -- Mr. Beamer performed a decline-curve analysis on the proration unit to determine from an active producing standpoint what that unit is predicted to produce.

So you've got two numbers. You've got the one that is determined from a volumetric evaluation, what that unit should produce. Below it, you've got the number that Mr. Beamer predicts that unit will produce, based on the current production from it today.

Q. Now, if that spacing unit has a single well, then he's used the production decline curves for that well; if it's a spacing unit with multiple wells, then it's a combination of those decline curves to get you the numbers?

A. That is correct. We take those two numbers, and we make a ratio of them such that --

Q. Well, let me follow the example for the Mewbourne example in tract 30.

A. Right, we take --

Q. If it exercised its opportunity to have its share of recoverable oil in its spacing unit, that share by this analysis is 172,000 barrels?

A. That is correct.

Q. Yet Mr. Beamer has concluded that if those wells are produced, they're going to recover 410,000 barrels of oil?

A. That is correct.

Q. They're going to exceed substantially their share of the reservoir's recoverable oil?

A. That is correct.

Q. What is the last number there?

A. The last number is that ratio. If the recoverable reserves, as determined from decline-curve analysis, equals the volumetrically calculated number, that should be one. If, in the example of the Mewbourne unit, the decline-curve analysis, the estimated ultimate recovery based on existing wells, exceeds that number, then that number is greater than one. And in the case of the Mewbourne unit that number is 2.39, which says that that unit is going to recover, in this example, 2.39 times more oil than it would have, calculated volumetrically.

I need to, at this point, introduce the next exhibit, which is related to these. This is Exhibit Number 9, and it's very simply a tabulation of the numbers that you see on the map, such that you have a map reference number, which corresponds to the proration unit reference number, you have a volumetric original-oil-in-place number in the next column for each proration unit, a volumetric reserves that would be recovered at a 20-percent recovery factor -- that is the second number on the map -- the amount of reserves that that well should recover.

The next column is EUR performance, the reserves that it is predicted it will recover based on the current production, and then again the ratio of that with wells recovering more than they seem they should based on the volumetric analysis being greater than one, and those recovering less, being less than one.

Now, let's get a couple of things straight on this entire map. If you take all of the volumes of oil predicted on the volumetric map, and you divide that by all of the volumes being produced, that ratio is not one. And that's one of the dilemmas of North Dagger Draw. That ratio is 1.25.

So that tells you that volumetrically, you're producing more oil than you really think you should. And we've noticed that in Dagger Draw for a long time. It's a phenomenon that we have recognized. Based on the best numbers you plug into the volumetrics formula, you recover a little bit more -- in this case a quarter more -- oil and gas than you think you should. That's great.

So the average to think about when you compare what a proration unit should recover versus what it's recovering, the ideal number is 1.25. That's the average for this whole map.

Q. That issue does not affect the credibility of this ratio comparison, does it?

A. No, because all we're doing is comparing pore volume to producing rates, ultimately. That's all we're comparing.

Now, when we take and we average all of the violating units on this map and that ratio of volumetrically what they should produce and what they are producing, that ratio, as you can see at the bottom of Exhibit 9 is 1.7. You're nearly producing twice as much as you would expect them to.

When you look at all the nonviolating units which surround it and you compare their ratios of what you think they should recover and what they are recovering, that ratio is less than 1. It's .9.

We would contend that the reason those ratios are so different when you examine pay thickness porosity, height above oil-water contact, the reason those violating units are recovering more, so much more than you think they should, is because they're pulling it off the adjacent leases, as a unit.

Q. Can you show us some examples of spacing units where we have an illustration of that concern?

A. As you can see on this map -- I'm referring to Exhibit Number 7 -- you have ϕh values that are ranging anywhere from zero -- meaning poor reservoir -- all the way up to eight. And as you can see, this map very well explains why certain units are capable of producing at the tremendous rates that they are. They have very high ϕh values.

For example, in the southeast quarter of Section 28 there's a thick in terms of ϕh. It approaches eight. It's surrounded by the State K Number 2, the Nearburg K Number 1, the Hinkle wells. Very high ϕh values. This is one of the worst violators in the proration unit, and it should recover more oil than other units that have lower ϕh values.

Q. What's the tract number on the display?

A. The tract number is not on this one, it's on Exhibit Number 8, and it would be tract number 28.

Q. Tract number 28?

A. I'm sorry, number 25.

Q. Yeah, I thought you were looking at the wrong one. 25 is the one in the southeast quarter of Section 28?

A. So that when you look at ϕh values and relate them to the productivity of the wells, there's a very good relationship there.

Q. You're giving that tract credit for its additional thickness, though --

A. You bet.

Q. -- in the volumetric calculation?

A. You bet.

Q. It gets for 672,000 barrels of recoverable oil, calculated volumetrically?

A. Because of the tremendous amount of porosity in that unit -- Even though it's thin, it has phenomenal porosity. Therefore it's going to recover a lot of oil and gas.

It also has the ability, because it's a large compartment, high porosity, high permeability, to drain that compartment at a phenomenal rate.

And that is the issue at hand: At what rate should we allow these compartments to be drained and not violate the offsetting correlative rights of the offset operators?

Q. When you look at the bottom number, it's 2.14. That spacing unit is ultimately going to recover twice its volumetric share of recoverable oil?

A. That is correct. And then -- and then -- well, volumetrically. So it's going to recover a phenomenal amount of oil, either way you look at it, but it's going to recover too much at its current -- the rate was when it was violating the allowable.

I'd like to point out one other thing on this map that is of interest. I got the impression yesterday, from

Mr. Fant's testimony again, that this is the first time he thought we had had rates, or wells, in this field capable of exceeding the allowable, and I'd like to point out an example on Conoco's acreage.

It would be on the far left-hand corner of your map. There is a unit -- On Exhibit Number 8, it's reference number 21 on Exhibit Number 7. It includes four wells, the Dagger Number 8, Dagger 11 and Dagger 16. I'll hold mine up and point to that unit so you can see it on the ϕh map. That is a Conoco-operated proration unit. It has very high ϕh values. In this case they approach seven. That's very high. That's very similar to what we're seeing in the violation area.

Conoco first drilled the Dagger Draw Number 8 in that proration unit. The old Dagger Draw Number 2 was a Hanks well that had been plugged before we took over the field. We drilled the Number 8 in that unit when we took over the field from Roger Hanks. The Number 8 was a good well, as you might expect it to be. It came on at a rate, I'm guessing, between 400 and 500 barrels a day, and stabilized to about 350 barrels of oil per day.

Shortly after we drilled the Number 8, in the next proration unit down, south of that, Nearburg drilled their Dagger 31 Number 2 well. That was a good well, and you can see why. It has very high ϕh values. It came on in excess of the allowable.

Conoco was concerned about drainage across our lease, and we faced the ultimate dilemma: We've got one well making a stabilized rate of 350 barrels a day, we're going to drill a second well, the Dagger 11, in order to protect our correlative rights across the spacing unit, knowing full well that if the Dagger 11 came in at a rate which combined with the Number 8 to exceed the allowable, we were going to have to constrain a well.

The Dagger 11 came in at over 1000 barrels a day. It was a great well. Here we are with a dilemma. We've got a proration unit that exceeds the allowable. What do we do?

In Conoco's mind, the operational inefficiency of cycling a well is something we don't even consider. You've got a $40,000-to-$50,000 submersible pump downhole, and you want to turn it off and on? Afraid not.

Conoco decided to shut in the Dagger Draw Number 8, a well making 350 barrels a day, and allow all the production to come from the Dagger Draw Number 11. Dagger 11 produced stabilized rates of 650, up near 700 barrels a day, for a period of about a year and a half, under the allowable.

All the while, during that year and a half, we had the Dagger Draw Number 8 shut in.

At some point, as is typical of compartments with good permeability, good porosity, the Dagger 11 crashed and burned, relatively speaking. We started seeing -- Straight declines for a year and a half, then it began dropping very rapidly. At some point we determined that it was equitable to bring on the Dagger Draw Number 8, about a year and a half later.

We brought the Dagger Draw 8 on. It came on at rates very similar to the rates when we left it, but it began a very steep decline as well, much steeper than it had when we first brought it on. Why? It had been interfered with, it had been drained by offsetting production. We're in a large compartment, easily drained. In this case we could have violated the allowable, but we did not.

It's a simple process of deciding from an operational standpoint how you are going to abide by the rules established by the OCD.

I'm done.

MR. KELLAHIN: Mr. Chairman, that concludes Mr. Hardie's presentation on North Dagger Draw. We're prepared to go into his discussion of South Dagger Draw at this point.

Q. (By Mr. Kellahin) Mr. Hardie, let me direct your attention to what is marked as Conoco Exhibit 1 now. We're using -- starting over with exhibit numbers, but each one of these exhibits will refer to the case number for South Dagger Draw. So don't let me confuse you; it's numbered as the South Dagger Draw case.

Let's start with Exhibit Number 1 and have you identify and describe that display.

A. Exhibit 1 is straight from the hearing that was held approximately a year ago in which Conoco as an operator came back to the OCD to re-examine a pool rule that we had implemented, pool-rule change that we had implemented in South Dagger Draw. That change, we thought, was necessary for the effective production of oil and gas from the South Dagger Draw Pool. It's not a change we made in North Dagger Draw; it's unique to this pool because, as we have testified, we feel that this is a different type of pool from North Dagger Draw.

Let me describe that change for you. Pool rules in South Dagger Draw are a little different than North. They're essentially double. We're talking about 320-acre spacing. The proration units are twice as big. The allowable is twice as large; you can produce 1400 barrels of oil from a 320-acre spaced unit.

The 10,000-to-1 GOR that exists for North Dagger Draw also existed for this reservoir. We were very concerned about that because, as we have described, South

Dagger Draw is essentially a thin oil rim to a very large gas cap. We're concerned about pulling too much gas from this reservoir, such that we're leaving oil behind.

We're also concerned about a clause known as simultaneous dedication, in which you are not allowed to have an oil and a gas well in the same proration unit. These proration units are big. It is very possible to have a portion of the reservoir that produces oil and another that produces gas. We're forced to decide which portion of the pay to complete if we come up with that dilemma where we've got an oil and a gas well. We've either got to shut in the gas well or complete up high in the old oil well and make them both gas wells.

Q. Now, that rule has a regulatory sense to it, does it not? It is the regulatory trigger or control in these associated pools where you have the opportunity to produce both oil and gas?

A. Right.

Q. And the issue, then, is whether that standard rule, in all associated pools, was to be modified for this reservoir?

A. We thought that it should be modified in this case, because there was the very likely chance that as a result of that rule we would leave oil in place, we would leave that thin oil rim unproduced. And we couldn't predict where that oil rim was going to occur. It was so thin that the ability to predict where it was going to be was beyond our means.

So when we drilled a well, we wanted to be able to produce that oil first and then get the gas. But in order to do that we felt it necessary to reduce the GOR, such that you could preserve reservoir pressure long enough to give operators a fair and equitable chance to recover that oil, yet still give operators of gas wells a chance to make good revenue. This is a very thick gas cap, so there is that opportunity to do it.

We proposed restricting the GOR limit to 7000. So that as a result of that hearing, the earlier hearing, the new rules are that you can produce 1400 barrels of oil per day, a GOR limit of 7000, which resulted in a 9.8 million-cubic-feet-of-gas-per-day withdrawal from a spacing unit.

9.8 million cubic feet of gas, 1400 barrels of oil. That's a lot of hydrocarbons that you can pull out of this reservoir. And at that time that was more than you could produce out of any existing wells.

A year later, we revisited this whole issue, brought it before the OCD to confirm that in fact we weren't violating correlative rights and that the rules were performing as expected. We produced this exhibit showing the various operators in South Dagger Draw.

There was also an opportunity for all the other operators to come in and present to the OCD any changes that they felt were necessary in pool rules. It was a year ago. A lot of good wells were drilled in that period of time. Conoco was the only company to show up and the only one to give a technical presentation. So there was an opportunity to change pool rules back then.

And this exhibit is included mainly just to show that the primary operators in South Dagger Draw, Yates Petroleum and Marathon Producing Company -- Conoco owns one, two, three, four units, right in the middle of the pool, and it just so happens that our acreage is right on that transition area where it's very difficult to predict oil or gas, which is why we were the primary leader in that hearing.

But I want to emphasize that we are a very minor participant in this pool. We're the ones who have been leading it. The other players have chosen not to effect any changes at the hearing last year.

Q. All right, let's turn to Exhibit Number 2 in this case, Mr. Hardie.

A. By now these exhibits should be getting familiar, because I've tried to use the same color schemes. Exhibit Number 2 has the red contours and is a structure map on the top of the Cisco dolomite reservoir.

A couple of points to make on this exhibit.

Solid green line outlines the South Dagger Draw Pool boundary. Solid yellow shading indicates Conoco-operated acreage. Cross-hatched yellow indicates that we have an interest in the unit, but we do not operate.

Again, structure in this area, as Mr. May referred yesterday, increases as we move to the south and into the Indian Basin Gas Pool, a good indicator that you're moving from oil production in South Dagger Draw into gas production in the Indian Basin Gas Pool, and you'll notice that the well symbols change as you move to the south and you start picking up those little gas symbols, and there is a line across which that change becomes very abrupt.

The pink dots indicate recently drilled wells in this pool. These wells were able to take advantage of the new pool rules, produce oil, some of them have gas wells within the units, but we are effectively producing oil from the oil rim over a very thick gas cap, as a result of those pool-rule changes.

We think they're good rules; we'd like to see them stay intact.

Q. Turn to Exhibit Number 3, Mr. Hardie.

A. Exhibit Number 2, again, is --

Q. This is 3 now.

A. Three, I'm sorry. -- an isopach of the dolomite reservoir, very similar to the one we looked at in North Dagger Draw, with the dark blue colors representing thin pay. As we get progressively more yellow, it indicates thicker pay, so that we're going from zero dolomite at the outer edges to a thickness in this case of upwards of 400 feet thick along the axis in the Indian Basin portion of the gas pool. So you can see it becomes very dramatically thick along its axis.

Also on these exhibits, I've -- Exhibit 2 and 3, I've outlined for you two cross-sections that I've included, cross-sections A-A' and B-B', in the dashed red line.

Q. All right, sir, let's look at Exhibit 4.

A. Exhibit 4 is an exhibit that I have pulled directly from that hearing a year ago when we re-examined the pool rules, so it has not been updated in many ways. The previous two exhibits are current as to the data available to me. This one is not necessarily that current; it's about a year old. But it's an effective presentation to demonstrate the difference in this reservoir and that of North Dagger Draw.

This is an isopach of the oil-filled portion of the dolomite. So that in this case we're going from light green, meaning thin oil-filled dolomite, to darker greens, meaning thick oil-filled dolomite. It's an isopach of the oil column.

And as you can see, that oil column, at least at the time of my knowledge back in 1995, September of 1995, ended at the current boundary of South Dagger Draw. That boundary is not that neat of a line. It comes in and out, you can miss it; you can hit the oil column, but there's no porosity in the zone so you can't produce oil. There are a lot of things that affect your ability to produce the oil out of this isopach, out of this column. But it dramatically shows that transition. As you move updip, you lose that oil, it's gone, and you go into gas.

I would also point out, just for the sake of further confusion, that I don't have both cross-sections marked on these older exhibits, this one and the next one we'll look at. So when we talk about cross-sections, we'll need to be sure to refer to Exhibit Number 2 or Number 3. Those have the cross-sections marked on them, both of them.

Q. Let's look at Exhibit 5, Mr. Hardie.

A. Exhibit 5 is the counterpart to Exhibit Number 4. It is an isopach of the gas-filled portion of the dolomite in South Dagger Draw and a portion of Indian Basin.

And the color scheme here is such that the yellow colors indicate thin gas-filled dolomite. And as we get more progressively and deeper into the red shades, we get thicker and thicker gas-filled dolomite.

You can see where Indian Basin field lies just by the dramatic color change that occurs as you move to the south. That gas cap gets very thick. There's a tremendous amount of gas that has been produced and will continue to be produced from the Indian Basin field. And I believe to date it's cum'd in the neighborhood of 1.5 trillion cubic feet of gas, and it's still going strong, a phenomenal reservoir, as are all of these, for the State of New Mexico.

Again, the concern here is that South Dagger Draw can be most adequately described as a gas field with a thin oil rim beneath it. And those are the pool rules. That's what we need to have in mind when we establish pool rules, allowables and GOR constraints upon production limits.

Q. Let's go to the cross-sections.

A. Again, we need to refer to Exhibit -- Either Exhibit 3 or 2, looking at the cross-sections.

Q. First cross-section I have is Exhibit 6. It's the A-A' cross-section.

A. If you look on one of your maps, either Exhibit 2 or 3, you can find cross-section A-A'. This is the same cross-section that I included when we revisited the pool-rule changes a year ago, and I used it to document -- I used this cross-section to document the inability that we have as operators to predict whether or not a well will make gas or oil.

As we move along this cross-section -- I'll point out first of all that there's a reference elevation, again, a heavy red line, and that elevation line is at minus 4000 feet, and that approximates the gas-oil contact.

And like our oil-water contact, that's an approximation. That is a transition, not a contact. If you are completing above that line, it is most likely that you will make a gas well. If you complete in a zone below that line, you have a very good chance of completing it as an oil well. However, if your zone that lies in the oil column is tight in terms of porosity and permeability, you may not have the opportunity to make it an oil well and you have to shoot up high and get the gas.

As we move along this section, you can see that some wells have a thin oil column available to them. They've completed in it and they are technically oil wells. Others, as we look, for example, at the Yates Number 1 Mojave, has virtually no pay beneath the reference elevation line. It's a gas well. They shot it up high.

The Marathon Number 1 Stinking Draw on the right-hand side of your cross-section is a well that was completed in the oil zone. The oil zone was tight, did not produce much oil, so they went up and shot up high and made it a gas well.

It's hard to predict whether you're going to make a gas or an oil well out here. But it's essential that you restrict gas rates such that we have the opportunity to produce the oil as we find it.

Q. The last cross-section is marked Exhibit 7. It's the B-B' cross-section, Mr. Hardie. Would you identify and describe that display?

A. This a new display from that previous hearing, back in September of 1995. It was not included then. And in fact, most of the wells drilled on this cross-section were not drilled back then. And this again demonstrates the ability or inability of operators to produce oil in South Dagger Draw.

Again, I've got the reference elevation of minus 40,000 [*sic*] feet subsea across this line. It looks kind of like a 1, but it is a 4. I think the ink has bled together. That dotted red line is at minus forty -- 4000 feet subsea.

I'd like to point out another zone that occurs in this cross-section that we didn't see in the other one, and that is what Conoco terms the C 5 zone. I've got it labeled in the middle of the cross-section. The top of that C 5 zone is denoted by the heavy black line.

It's a correlable zone. It's a compartment that you can map geologically, a unique instance in this field where you can do that, because that compartment can be identified lithologically. It's either a dolomite or it's a shale or it's a limestone. And when it's a dolomite, it's reservoir and you can produce from it.

But it comes and goes across South Dagger Draw. Because it is at the bottom of the reservoir, typically, if it's below that minus-4000-feet-subsea line, you get oil out of it. And if you'll take a look at the oil rates that I've printed above these wells, you can see that you can produce incredible amounts of oil from that zone.

It's relatively thin. Again, it's got high porosity, high permeability. It's a compartment that's very easily drained because of those reservoir characteristics.

All the wells completed in that zone on this cross-section are producing high-rate oil, with the exception of one well, and I'll call your attention to the left-hand side of this cross-section, the Marathon Comanche Fed Number 3. Marathon was looking for the C 5 zone when they drilled that well in hopes of producing oil. They found the zone was there, but it's above that reference elevation. They completed in that zone. That zone makes all gas. Not one drop of oil is coming out of that zone.

Please refer on your map to the proximity between that Comanche Fed Number 3 -- 3 Number 1, and the adjacent well to it, the North Indian Basin Unit Number 23, approximately half a mile apart, one well producing all gas out of the same zone, but the adjacent well is producing -- or at least IP'd at nearly 1300 barrels of oil.

If there is not a need for regulate in a situation like this, then we never need regulation. We have a need here to constrain gas withdrawals in these zones, because we have wells producing oil and gas out of the exact same zones.

If we increase the allowable to what Yates is proposing in this case, 8000 barrels of oil per day, the gas rate increases proportionately with that 7000 GOR to 54 million -- or 56 million cubic feet of gas a day. I don't think that's appropriate. And I don't think Yates has fully examined the ramifications of those kinds of allowable increases in this pool.

Q. Let me have you take a copy of the Examiner Order, Mr. Hardie, and I think we have one somewhere there --

A. I've got it.

Q. -- on your desk.

I'd like to ask you Conoco's position and recommendation with regards to the major aspects of what the Division Examiner required to take place.

I'd like to start first with the position Conoco has with regards to the operator committee that is ordered to be formed and to undertake an investigation of the technical aspects of both pools and to report back their recommendations and conclusions to the Division Director by -- I've got the deadline in here. I think it's an 18-month period. It begins on August 15th of 1996, and the committee has a -- up to about 18 months, I believe, in order to complete their study and make recommendations to the Director about changes in operational rules. What's your position?

A. Our position on that is that we've worked with Yates and other operators in this pool in the past. Admittedly, we don't agree on everything. But if we work together, the chances of us agreeing and avoiding having to come before you to publicly air our debates, I think, are greatly reduced. We're all in favor of working with other operators to achieve an equitable allowable, an equitable set of rules for producing these reservoirs. I can't say that if we meet on these pools that we would agree with Yates, but we haven't tried.

Q. Is there a material difference between operators' methods in drilling and completing and producing these wells?

A. There's some differences. There is an effort on, I know, Yates and on Conoco's part, to avoid completing in the gas cap. We want to get that oil out, that oil is valuable. We don't want to leave it in the ground.

Q. All right. I didn't make myself clear.

A. That's not what you mean.

Q. In North Dagger Draw, in terms of having a high-capacity -- one of these superstars, versus a lower-rate well, is that attributable to the method of drilling and completing the well?

A. No, that's attributable primarily to -- Conoco and Yates complete wells and drill them in very similar fashions. There's some minor differences. We achieve similar rates. We have in the past, we still do. The main difference --

Q. Is the technique for producing them substantially different?

A. No, we both use the same types of pumps, we use the same vendors, the vendors talk amongst themselves, they talk amongst us. A lot of exchange of ideas that go on technically between Conoco and Yates, such that we don't operate that much differently, with the exception that from a standpoint of developing our reserves in the unit, we operate differently.

We are not as prone to drill, say, a proration unit that has a 500-barrel-a-day rate. It's unlikely that Conoco is going to jump in there and drill another well, knowing that we must restrict that well to 200 barrels a day. Operationally, that's a nightmare for us. We don't want to do it. You end up losing money. If you're producing 200 barrels a day out of a well you're cycling and you're burning up a pump every month, it doesn't make sense.

Yates, on the other hand, has a different philosophy towards that. They may someday discover a way, creatively, whereby they can cycle wells and produce them at restricted rates, not creating waste. We haven't figured out a way to do that, so we just wait until we have sufficient allowable to drill the well. It's a choice that each operator must make in a unit that is capable of exceeding the allowable. That's why we have allowables. It's to prevent waste, prevent excessive withdrawals from the pool.

Q. In such a competitive reservoir as North Dagger Draw has become, Mr. Hardie, what is your recommendation or your company's position concerning changing or increasing the rates of withdrawal as set forth in the allowable?

A. Our position is just as it was when we first proposed the rate increase back in 1991, that the allowable established back then is appropriate. It sets a balance between an operator's ability to efficiently produce his wells and the need to protect the correlative rights of offset operators. Somebody's got to lose. There's not one perfect rate. There's a balance, though, and we feel that the current rates in both North and South Dagger Draw have achieved that balance.

Q. What's your position on canceling the overproduction?

A. As we mentioned before, because we feel like we've been detrimentally affected by that overproduction, canceling it is certainly not the proper option. That's a violation of existing rules. It was done over a period of over a year, and in many aspects it appears to be willful. There should be some consequences for doing that. We have pool rules. Mr. LeMay, you're here for a reason, Mr. Gum is here for a reason, and that is to regulate these types of competitive pools. You have a function, and we fully commit ourselves to supporting you in that function.

Q. What's your position with regards to the make-up method and the period of make-up? In other words, to produce the spacing unit up to 350 barrels a day in North Dagger Draw, provided the total volume of overproduction is made up in the 18-month period?

A. Conoco is willing to comply by the orders that are issued by the Division. We feel that the most equitable means of remedying the overproduction is to shut in the existing wells. That gets the problem taken care of quickly, minimizes the damage that may be caused by cycling wells in the process, and gets us quickly to a position where everybody is obeying the law and can then begin developing this field in a prudent manner.

MR. KELLAHIN: That concludes my examination of Mr. Hardie.

We move the introduction of his Exhibits 1 through 9 in the North Dagger Draw case, which is 11,525, and his Exhibits 1 through 7 in South Dagger Draw, which is Case 11,526.

CHAIRMAN LEMAY: Without objection, those exhibits will be entered into the record.

Mr. Carr?

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Hardie, I think we can cover a number of these things just finding again what we're in agreement on.

It's my understanding that we agree that we're dealing with very complex reservoirs here when we're talking about the North and South Dagger Draw Pools; is that right?

A. That is correct.

Q. And we discussed in May, I think we're in agreement that as this reservoir has continued to grow and continues to grow, we continually discover there's more and more we need to learn about the reservoir; is that not right?

A. We are learning more about the reservoir as it grows. The fact that it's as big as it is, is new knowledge. I don't think anybody here would have guessed that it was going to be this big.

Q. And as we go forward there are more things we still have to discover and study about the reservoir; is that right?

A. That is correct.

Q. We don't have a homogeneous reservoir here, do we?

A. We do not.

Q. We have multiple porosities in this reservoir?

A. They do vary.

Q. And they vary across the reservoir?

A. Yes, they do.

Q. Permeability variations also occur across the reservoir; isn't that correct?

A. Certainly do.

Q. The reservoirs were established by -- We have two pool in part because we had two separate discoveries, and the pools grew together; isn't that right?

A. That is correct.

Q. Do you know of any reason for the boundary between North and South Dagger Draw, other than that's just -- as there was stepout development, that's where they met?

A. That's where they met; that's why that boundary exists.

Q. There's no technical study that decided that's where the appropriate boundary ought to be between North and South?

A. There's no technical reason that there is -- that boundary exists where it is.

Q. Now, we are currently dealing with overproduced wells in North Dagger Draw?

A. Yes, we are.

Q. We agree on that. We also -- There are also some overproduced units in South Dagger Draw; is that not right?

A. To my knowledge, there are -- The data we have to date is somewhat sketchy, but I believe that there are.

Q. I believe you testified that we don't really have a dispute on the understanding in this reservoir that with higher rates there are higher oil cuts?

A. That is correct.

Q. Were you involved with the hearings in 1991 where the 700-barrel-of-oil-per-day allowable was established?

A. I was involved inasmuch as I was present. I did not testify. I think I was considered too new to do so.

Q. And you no longer have that luxury?

A. I don't. I wish I did sometimes.

Q. Isn't it fair to say that back in 1991 what we were trying to do, Yates and Conoco came together for a presentation to the Oil Commission, trying to set allowables at a level that would allow these reservoirs to be produced at the lowest bottomhole pressure?

A. Yes, that is correct.

Q. And the net result was, at that time, we really were producing wells with unrestricted rates under a 700-barrel-per-day allowable?

A. At the time of that hearing, that was the case. As soon as wells began getting drilled, it wasn't very long after that that we started bumping that allowable.

Q. The D State Number 2, the well you talked about as the fantastic well off to the west of the area you called the violation area --

A. Section 36.

Q. Right. That was one of those wells, was it not? That was in the south half of 36?

A. Yes.

Q. And I believe you testified that that well produced for a couple of years at a rate of 500 to 600 barrels per day; is that right?

A. That would be my guess. I don't have production data in front of me. I'm relying on my memory --

Q. Sure.

A. -- for this, so --

Q. Were you restricting that well, or was that the level that hit a sustained production rate?

A. That well may -- may not have been able to produce at higher rates. That was the rate at which the pump was running in the well.

Q. With that pump running on that well and at that rate, were you able to keep that well pumped off?

A. I'm assuming that that well was relatively pumped off.

Q. So it was efficiently produced?

A. Yes.

Q. Has Conoco drilled any wells in the pool that have an initial potential of over 2400 barrels of oil per day?

A. Conoco has not done that. I don't know whether predecessor Roger Hanks did that on the same acreage or not, no.

Q. Are you aware of any Conoco well that has a stabilized -- or stabilized at a producing rate of 1300 barrels a day like the Polo well?

A. Stabilized rate of 1300 barrels of oil per day?

Q. (Nods)

A. Now, my point, Mr. Carr, is not that we have an individual well that could break or violate the allowable. It is that we have had the ability, usually through a combination of two wells, to do so on a sustained basis.

Q. And my question is that when we talk about effective producing rates, there's a difference between a spacing unit on which one well can exceed the allowable and a spacing unit on which you have to have multiple wells to exceed the allowable; you'd agree with that?

A. You bet.

Q. And if you have a situation where you have one well on a spacing unit, like the State K Number 3, the Nearburg -- the Yates well that has stabilized at over 1000 barrels a day, under a 700-barrel-a-day allowable you have to restrict that well, don't you?

A. You have to restrict that well, and I fully admit that in so restricting that well, you will have a higher water cut. That is something that we as operators have recognized all along.

Q. And --

A. My point is that there has to be a balance between the kind of rates that that well can produce and the effect it has on offset operators. It may be --

Q. And my point is that you have to restrict the well, wouldn't you?

A. Yes, you would, absolutely.

Q. And by restricting it, you couldn't produce it at the lowest bottomhole pressure possible?

A. No, you could not. And I would also like to point out that there's some question in my mind as to whether that early water, the excess water that you produced, will be made up later in the life of the well.

Q. But we don't know that, do we?

A. We don't.

Q. Okay. Now -- And if we are restricting the well, we're not at that point able, perhaps, to keep it pumped off; isn't that right?

A. You cannot pump off a restricted well.

Q. Okay. And so we wouldn't be able to produce, say, the State K Number 3 in the most effective way, because we can't keep it pumped off; isn't that correct?

A. That is correct.

Q. At this point in time, does Conoco have any wells that produce in excess of 700 barrels a day, individual wells?

A. Not at this point in time.

Q. So you would have no wells that would be restricted by maintaining the current allowable?

A. We could, if we chose, drill additional wells in the existing proration units and achieve that problem. We have no desire in doing that unless there's some other compelling reason, perhaps offset drainage or some situation, to do so.

Q. But you have that choice by drilling an additional well, and you've elected not to; isn't that right?

A. Until such time as rates decline to the point where we feel like there's little risk of having to curtail a well.

Q. If you have one well that stabilizes at 1300 barrels a day, you don't have that choice, do you?

A. You certainly don't.

MR. CARR: That's all I have.

CHAIRMAN LEMAY: Additional questions of the witness?

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. You mentioned the problem between the D State -- When it was drilled, you felt that the bottomhole pressure indicated that there had been a certain amount of drainage by the Yates Foster well?

A. In that example I was referring to the first well, the D State Number 2, which produced for a significant period of time, began experiencing rapid depletion, at which point we drilled a second well, the D State Number 4, which is northeast of that location.

If you'll look in the southwest corner of Section 36, you can see the D State Number 4 labeled, one of the two wells that exist in that proration unit. That second well is the one that -- we drilled it -- The nearest and only offset was a well approximately a quarter of a mile away, drilled by Yates Petroleum. So it's two wells out in the middle of nowhere, essentially, and we had a bottomhole pressure of 400 to 500 pounds. Clearly had to have been drained by the good D State 2 well and by other offset operators.

It's my -- My point is in describing that event that we have a large compartment -- in this case, it extends for much more than one proration unit -- and it was drained very quickly and efficiently by a single wellbore.

Q. How long of a time period was there between the completion of the Yates Foster well and the completion of your D well?

A. Actually, the D State Number 2 was drilled before I started, right as I began, so I'm not sure on the history of those. I expect they were relatively close together, but I don't know that for a fact.

Q. And by the time the D State Number 4 was drilled?

A. That was approximately two years later.

Q. Two years later?

A. Uh-huh.

Q. Is it incumbent upon Conoco to prevent drainage under their state lease?

A. Absolutely, and we did so, we drained our state lease with our single wellbore.

Q. Even though you were not producing at the allowable and you could see that the Yates Foster well was draining it?

A. We were directly offsetting the Yates -- You're talking about the State CO Number 4 well. That is correct, we did not have available allowable.

You've got to keep in mind that when you're drilling a well and you have only 100 barrels of allowable left, that operationally you're going to have to cycle that well, you're going to have to turn it off and on.

If you start burning up electric submersible pumps at a cost of $40,000 to $60,000 a pump, on a rate of one to two per month or every couple of months, you're not going to make any money. You're going to create phenomenal waste if you're producing 100 barrels a day and you're burning out pumps. So you're creating value for the pump company, but that's about all.

And from a volumetric standpoint, when you examine these types of leases and you look at the reserves that have come out them and the amount of ϕh available under that lease, usually those high-rate areas have actually produced more than they should, even from the single wellbore.

Q. I'm looking at your Exhibit Number 7 for the Case 11,525, and then Exhibit Number 8 in comparison.

A. Okay.

Q. The inference was made off of Exhibit 8 that those reference-numbered areas were greatly influenced by the overproduction as the areas in yellow, and we can see so clearly that to the northeast those referenced areas have .04, for their volumetric reserves, .66, way below the figure of 1.25 that you say is reasonable for this area.

But when we look down at the southwest, we see also, and to the west, that some of these referenced areas are way above 1.25, and showing -- what? 1.48, 1.64. Have these areas benefitted where the others to the northeast have seen a detriment?

A. That's a very good observation. The ones to the northeast, the reason -- one of the reasons they may be so low is because they're so new, and they have not yet achieved the number of wells in them to drain them efficiently. So they're low because of that, perhaps.

It may just be that due to some mechanical or --

There are areas that we simply can't explain. They should recover a certain amount, and they don't. There are other areas that recover slightly more. So there's going to be a variability around that figure of 1.25, regardless.

But when you average everything together, all the violatings versus all the non-violatings, and that entire average is significantly higher, there is a way to attribute that, and one of the ways is to propose that perhaps those violating units are draining more than they should.

Q. But would you say those sections to the west and southwest have benefitted from the overproduction?

A. The ones that have overproduced have definitely benefitted.

Q. But those outside of the overproduced --

A. Those outside, one of the reasons they may have produced more than they seem they should have is because they were the -- at the time they were drilled they were the easternmost wells in the field. And there was this period of time when those wells sat there draining this undeveloped, undiscovered area, for a period of time. Within the law they did that, within the allowable, because we hadn't discovered that portion of the field yet.

So typically, those older wells along that flank will have values that exceed what you think they should.

They're draining large areas, but they're doing it within the confines of the law. That does happen.

COMMISSIONER BAILEY: That's all I have.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yes, sir, has Conoco had any consideration -- given any consideration to unitization of this field?

A. Unitization was discussed internally, and we've had informal discussions with the technical people at Yates. And because of the quagmire of ownerships in this unit, although there are a few operators, there are many, many different working interest owners, and the effort taken to unitize this would have been asinine, it would have been tremendous. And both parties felt like it probably wouldn't have happened.

I will be the first to admit that this pool begs for unitization. There's no question about that. Every dispute that we have could be resolved if this were unitized and a committee operated the field. But it's a competitive reservoir, and that's why we have pool rules established, to control competition and excessive withdrawals from existing units.

Q. You mentioned verbally numerous examples of interference, an example if weak -- you mentioned weak water drive. I guess these will be presented in the engineering testimony?

A. I think Mr. Beamer will probably give them a bit more detail than I'm capable of.

Q. And then on your volumetric maps, it seems like sometimes in these vuggy carbonate reservoirs, that porosity is difficult to estimate.

A. You bet, and in my opinion it's -- I don't know, criminal is probably too strong a word, but it's in some ways criminal not to run some form of an imaging log in every well you drill out here. Conoco as a policy runs some form of an imaging log so you can see what that wellbore looks like, because you're absolutely correct. And much of the secondary porosity, particularly in zones where you have a tight matrix and big vugs, you get an underestimation of what that zone is capable of producing.

That's not the case in the violation area. We've heard everybody testify that it has a good matrix. You cannot achieve these kinds of rates with a bad matrix, I'll assure you of that.

But nonetheless, our volumetric estimates would be more accurate if we had an imaging log from every wellbore. And because Conoco doesn't operate this area, I had access to no imaging logs, and I included no imaging logs in my evaluation. Everything is done with standard open-hole porosity logs.

Q. That can, I've been told, lead to errors of 100 percent.

A. And it certainly can, particularly, as I said before, when the matrix is tight. That's when you encounter the errors.

I don't think that's the case in this area. I know it's not.

COMMISSIONER WEISS: Those are the only questions I had. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Hardie, you initially said what -- I guess my question is, what is your definition of significant illegal oil?

A. My definition of significant illegal oil is if you don't catch it in the first month, you do it. And I don't know what Conoco's history is. I know that when we have a high-rate well, I watch it. And I'm ready to pick up that phone and call the field and say, Shut that thing in or curtail it or something.

And even so, it has happened that wells under my watch have for one month exceeded the allowable by a rate of perhaps -- I'm guessing -- instead of the 700 barrels a day for one month we may have produced 800, in looking at the plots. And I still to this day don't know how that happened. I thought I had calculated everything correctly. Obviously I made an error, and I take full responsibility for that.

Q. So you're saying -- To your knowledge, has Conoco ever exceeded the allowable for more than one month?

A. To my knowledge, it's never been for more than one month.

Q. How about other operators? Do you know their policies on -- That's probably an unfair question in a competitive reservoir. We're getting -- testifying from Conoco and Yates, and we have other operators in the field, and -- Do you know their policies at all?

A. I don't know their policies.

Q. You don't?

A. No, it seems like we're discovering it as we go here.

Q. Okay, I have -- Commissioner Weiss asked my unitization question.

Anything more you want to -- You said because it's too complicated you decided not to try it, I guess, huh?

A. It truly is a nightmare. Many of the working interest parties in this part of the world don't get along very well. They're --

Q. They're not uni- -- Well, we understand that. We're very busy here at the Division level with parties that can't get along in these North and South Dagger Draw reservoirs.

A. The operators actually get along more than you think they do, at least Conoco and other operators do.

Q. Your maps 7 and 8, or your Exhibits 7 and 8, in looking at decline curves, you're accumulating -- I mean you're adding together -- If there are three wells on a proration unit, you would add all three decline curves together so that a decline-curve analysis, I guess, on one well in a proration unit would show less recoverable oil than a decline curve analysis with three wells on that proration unit, but you're matching that to the volumetrics that --

A. Right.

Q. -- that you would assume that would be consistent. I mean, you have -- It seems like you would be favoring recoveries from wells with more than one well -- three or four wells on a 160, rather than one well.

A. If the compartment were small, that's the case. If it's a big compartment and one well is effectively draining it, then that decline-curve analysis is a good estimate of what's going to be produced from it.

In the case of our D State 2 example, we didn't recover much oil, much incremental oil, from the D State 4. We did recover some. It's a marginal well.

Q. How much do your wellbores consist of compartments that maybe have been drained, or at least the good wells, along with some of these compartments or zones that haven't been penetrated on one well? A combination of the two?

A. Probably a combination of the two. I can't say that we have never encountered a compartment that's been drained and then one that hasn't. I can't say that happened.

Q. Has that been the norm or the exception?

A. In my experience, it's been the exception. And I'm not saying that applies to the entire field, necessarily. There are compartments in this field. Some of them are very large, some of them are small.

Proration units with small compartments need four wells. Yates very accurately showed that to us.

I'm telling you that proration units with large compartments, and typically the ones that have very good permeability and porosity, don't need four wells.

Q. And your -- maybe not your figure, I won't attribute this to you, but you've defended 700 barrels a day. Is that magical, or is that a compromise figure between maybe what might be efficient rate and the protection of correlative rights?

A. That's, in my mind at least, a compromise between correlative rights and efficient rates. I think that compromise is going to require that some wells be constrained, otherwise it's not a compromise.

CHAIRMAN LEMAY: Commissioner Weiss, do you have additional questions?

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, I have one more question concerning unitization and a committee, I think, the procedure that was -- as suggested in the Order. I don't quite understand the difference there. You say that, you know, unitization is not possible but a committee is a good idea.

A. No, a committee which is designed to attempt, at least, to work out pool-rule issues, and I did say that I wasn't certain that we could work it out. But we haven't tried.

Q. Uh-huh.

A. And rather than stand before you and air out our dirty laundry, I'd rather do that in Yates' office or them come to us.

That's why I tell you it's somewhat disappointing that as operators we get along more than we don't, I think, and every time we don't we're here to do it publicly, so that I think it looks worse than it really is.

COMMISSIONER WEISS: All right, thank you.

CHAIRMAN LEMAY: Additional questions of the witness?

If not, he may be excused. Thank you very much, Mr. Hardie.

Let's take a break, fifteen minutes.

(Thereupon, a recess was taken at 10:38 a.m.)

(The following proceedings had at 10:53 a.m.)

CHAIRMAN LEMAY: Okay, Mr. Kellahin, you may continue.

MR. KELLAHIN: Thank you, Mr. Chairman.

<u>ROBERT E. BEAMER</u>,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Robert E. Beamer. I'm a petroleum engineer for Conoco, Incorporated, in Midland, Texas.

Q. Summarize for us your education and employment experience, Mr. Beamer.

A. I have a bachelor of science degree in petroleum and natural gas engineering from Penn State University, as well as a master's degree in the same field from Penn State University. I started to work for Conoco immediately after graduation in 1960.

Q. Summarize your experience in Dagger Draw.

A. I've been associated with the Dagger Draw operation for about the past two years, as a reservoir engineer, working closely with Mr. Hardie and the production engineering department.

Q. As part of your work with Mr. Hardie, have you reached certain engineering conclusions with regards to the proposal made by Yates that's before the Commission today?

A. Yes, I have.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Beamer as an expert reservoir engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

MR. KELLAHIN: Mr. Beamer is -- This is his last official function, Mr. Chairman. He's retiring on October 1st from Conoco and --

THE WITNESS: (Thumbs-up sign)

MR. KELLAHIN: -- this ends his career.

CHAIRMAN LEMAY: Well, congratulations to you.

THE WITNESS: Tomorrow is my last day.

MR. KELLAHIN: Tomorrow is the last day.

MR. CARR: I don't know, we may not be finished.

(Laughter)

CHAIRMAN LEMAY: It's been noted that consultants make more money going back to their companies after they've retired.

THE WITNESS: I won't be near here.

Q. (By Mr. Kellahin) Mr. Beamer, let's turn your attention to North Dagger Draw. I'd like to go through the submittal to the Commission of the production data that you've tabulated for the violation area, and then we'll get down to the technical aspects of your conclusions with regards to our contention that Conoco's correlative rights have been impaired in North Dagger Draw.

Let's start with the data. If you'll look at the booklet, it's the legal-sized paper found at the top with the spiral. They're exhibits numbered 10 through 24. Describe for us what we're looking at when we see this package of documents.

A. For each exhibit number, 10 through 24, when you open your booklet, the top sheet relates to the bottom graphs. You saw a copy of the tabulation from yesterday's testimony from our May session, and it is simply a tabulation of the oil, gas and water production history for a given proration unit, which is identified in your left column, and in the case of Exhibit 10 we're looking at northwest Section 21.

Q. All right, let's make the connection.

A. All right.

Q. In this case, Conoco Exhibit Number 6 is the display that shows the location of those spacing units in the violation area, and then there's a number that shows the total volume of overproduction?

A. Okay, in that Exhibit Number 6, the location reference number for each of the proration units which have been in violation over the past year and a half or so are numbered in the upper left corner on that map, and they are referred to at the bottom of this tabulation as overproduced unit number 1.

Q. This data, then, in this exhibit package supports the concluding numbers shown on Exhibit Number 6?

A. The concluding numbers on Exhibit 6 were drawn from these tabulations.

Q. All right. Show us how this particular set of documents, Exhibits 10 through 24, are different from a similar set introduced at the Examiner hearing.

A. The only difference is that we have added the additional months of production history available to us at this time.

Q. All right.

A. I believe at the May hearing, for most of these production units, we had data available through about March or April. Today we have data through June of 1996, so --

Q. All right, let's take --

A. -- so these differ only in update of data availability.

Q. Let's take the first one, then, for the northwest of 21 and have you show us how you've organized the data for presentation.

A. Again, it's a tabulation of the production history, comparing the actual monthly oil produced versus the allowable oil allocated to that proration unit. The allowable oil is noted in the second column from the left of each sheet.

When any one of these proration units exceeded the allowable for a given month, I bolded the overproduction number on the right-hand column and began a shading just to draw our attention to that point in time at which we would start accumulating the overproduction.

For this proration unit, we exceeded the allowable rate for a period of five months, at which time from the plot below, you can see on the upper plot where I've plotted actual barrels of oil per day versus the allowable oil. This proration unit, because of natural decline, it appears, went below the allowable rate, and we started seeing negative numbers in the right-hand column, which then began to make up for the over-allowable.

Q. All right. So if there's a negative number in the last column on the right, then that indicates that --

A. That means that for that month --

Q. -- it was in compliance?

A. -- the proration unit was in compliance.

Q. All right. And if it doesn't have a negative number it shows that in that month it was exceeding its allowable.

A. And any exceeded volume is in bold print, just to highlight it.

Q. All right. When we look at the bottom half of the display, when this is folded in this fashion --

A. Yes.

Q. -- the top portion is the tabulation of the production data?

A. Yes, sir.

Q. And we look below it on the next page, what are we seeing then?

A. The next page is a combination of performance plots. The top plot, as I mentioned earlier, is a plot of the actual oil production from this proration unit in barrels of oil per day, versus the allowable rate, which is shown as a solid bold line at 700 barrels per day. Any production, of course, above that allowable rate, then, is identified as the excessive oil or the illegal oil produced for this unit.

Q. And as we flip through these, then, you've done the same thing for all of the spacing units that are identified on Exhibit Number 6?

A. Yes, I have.

Q. Let's go, then, to the last page and look at Exhibit 24 and have you summarize for us the magnitude of the overproduction.

A. I think, Mr. Kellahin, before I go to Exhibit 24, I would like to make a point.

Looking at the data on these proration units, it becomes apparent to me that we're withdrawing fluids from a volumetric reservoir. Our rates are declining over time, total fluid production rates are declining over time. To me, this indicates that we are withdrawing a given volume of fluid. There is no evidence of any influx at all into these proration units.

I agree with Yates' testimony yesterday that producing at higher oil cuts -- or at higher oil rates, do result in higher oil cuts. I do contend, though, that when you produce in that manner you are withdrawing significant higher volumes of total fluid from the reservoir, and in this particular reservoir that accelerates the rate of pressure decline, and we will see that later.

Q. When we look on Exhibit 24, then, that is simply the end result of the tabulation of the overproduction, and it shows the operator for the units that are overproduced, and it shows the volumes?

A. Yes, it does. And the significant feature of this is that on reference number 4, for instance, in the northwest section of 29, this unit is now in compliance as a result of natural decline.

One addition to this tabulation, as opposed to that presented in our May session, is the addition of the Mewbourne unit in the northwest of Section 33. As Mr. Hardie testified to earlier, we just within the past week became aware of this violating unit, and so we have included it in the documentation for documentation purposes.

Q. All right, sir. Let's turn to Exhibit 25. Let me have you identify and describe this display.

A. Exhibit 25 is a performance history of the Conoco-operated proration unit in the northeast section of 32, of Township 19 South, 25 East.

We had -- At the time this plot was prepared, we had one well completed in this proration unit, the Savannah State Number 1 well. We are in the process right now, this week, of completing and testing the second well in this proration unit.

And it shows a dramatic decline in oil rate. You will note that in the first month of production we were overproduced by approximately 70 barrels per day for that one month. Natural decline, of course, occurred, and we rapidly became compliant in this proration unit.

Q. What's your point, Mr. Beamer?

A. Well, this -- My point is that we are completed -- Well, let's go back and review Mr. Hardie's testimony.

We realize that this unit, this proration unit, is toward the edge of the dolomite fairway. It does have limited reservoir volume to draw from. We do believe that excessive fluid withdrawals in the past have appreciably affected the pressure support that we could have enjoyed from this proration unit, and we do see rapid production decline.

Q. Turn to Exhibit 26 and have you identify and describe that display.

A. Section [*sic*] 26 is the exact same type of performance history for the adjoining Conoco-operated proration unit in the northwest section of 32, in which we have drilled -- completed two wells, our Joyce Federal Number 1 and Number 2.

Again, for the first month of production history we were over the allowable by approximately 100 barrels per day. Again, natural decline took care of that very rapidly, and you can see from that first well that it suffered a very high rate of decline, not entirely sure as to the reason for that. We have recently gone in and recompleted and added some perforations in that well, which we think will add some recovery.

You can note the effect of the second well in this proration unit in that it did flatten our proration unit production decline somewhat. In fact, dramatically. However, beginning in early 1996 we did see an increasing rate of decline from this unit.

Q. Yesterday, Mr. Fant provided data on the Polo Number 6 well, and based upon that data he concluded that that well, because it had been restricted, lost the ability to return to the levels of productivity that it had enjoyed before it had been shut in. I believe there was a shut-in period. And he attributed that to some wellbore damage, as opposed to having been depleted by natural depletion or drainage by offsetting properties.

Have you had a chance to examine that plot?

A. Well, I did.

Q. Let me pass out the plot so everybody's got a copy.

A. The plot of Polo "AOP" Number 6 is plotted on a daily production basis for approximately a five-week period, and I see here a trend that we have observed in both our Joyce Federal Number 1 well and our Savannah State

Number 1 well.

Q. The line of decline is a line that you have put on Mr. Fant's display?

A. I have placed the dashed line there, just to see whether this would fit with trends that we have observed in our producing wells in this portion of the North Dagger Draw field, and I contend that this could be attributed to a natural decline caused by pressure decline from offsetting production. Obviously, there are two different thoughts on this, but this to me is a very plausible explanation for this loss of production.

Q. Yesterday, Mr. Fant provided us an example. With his Exhibit 15 he was looking on the first page, I think, in the southwest quarter of 29. There was an example of a spacing unit in which Yates had took the opportunity to drill four wells, and he was showing that data.

I'm going to hand you a copy of that exhibit on which you have added some additional decline lines. Let me give you a copy of that.

A. Again, I'm suggesting only a second interpretation of the available data.

Q. All right, let's make sure the record is clear on a distinction between Mr. Fant's interpretation of the decline and the interpretation you've placed on this display. I think as photocopied, yours are slightly darker, and yours are the dashed -- long dashed lines; is that right?

A. That's correct. And to reiterate Mr. Fant's testimony, this is a production history plot on a Cartesian coordinate scale, of oil rate versus cumulative oil production, which provides a standard extrapolation technique to determine estimated ultimate recovery.

I might bring your attention back to my Exhibit Number 15, which shows the same data, only plotted versus time.

Q. Let's do that, let's let everybody have a chance to find 15. It's in the package that we --

A. It's in the package that we just reviewed.

Q. All right. We're looking at Exhibit 15, and we're looking at the bottom portion of the display. Again, we're in the southwest quarter of 29 and we're looking at your Exhibit 15. Explain your point.

A. My point is that in the top portion of that plot, in which I plot barrels of oil per day versus time, it's very evident when each successive well comes on production, to me, that there is some increase in the production decline rate, as each well is produced.

And it's very apparent, after the fourth well is produced, beginning in late 1995, that that decline rate steepened significantly, which to me indicates that there is significant interference among the four wells in this given proration unit.

And I see the same type of data displayed in Mr. Fant's plot that we're looking at here on the oil rate-versus-cum production curve.

I'm only suggesting that we can approximate that the total ultimate recovery from this proration unit in the southwest quarter of Section 29 could have been achieved with the drilling and completion of three wells. Granted, the fourth well did add significant oil rate, but I'm contending that that is rate acceleration only -- significant rate acceleration, of course -- but that given enough time, three wells could have drained this section.

My point is that interference does occur.

Q. Let me have you turn our attention to what is your next numbered exhibit. We're up to Number 27.

A. Yes.

Q. You've made an examination of the pressure relationship of certain wells to another?

A. Yes.

Q. All right. Let's find the area that you're examining, and then let's talk about the display. Where are we concentrating in the pool when we look at this data?

A. We're talking -- On my Exhibit 27?

Q. Yes, sir.

A. This is the available static bottomhole pressure data that I was able to compile for the Township 19 South, Range 25 East area, which is essentially the area that we are talking about the excessive oil production. So it encompasses this entire township.

And again, from available records through a PI database, plus our available scout-ticket records in Conoco's office, I have prepared a tabulation and then have plotted this data to show the significant pressure decline over this township that has occurred because of the significantly influenced fluid withdrawal rates.

We'll have to look at this in combination with Exhibit 28. I apologize for not putting the pressure data on the same plot, but I just didn't want to take the time to work it out.

We are looking at a time history from late 1962 through -- the last data point that I have available to me was one taken in our recently completed well, Savannah State Number 2, August of 1996.

These pressures are all referred to a common datum of minus 4000 feet subsea. I picked that datum point because when we look at the South Dagger Draw data I have done the same thing, and I wanted to compare the early production history to that, to show that this is indeed a common reservoir geologically over this 40-mile expanse.

We see a pressure decline from late 1962 through somewhere -- and again, the date -- or the time scale on this Exhibit Number 27 could be a little confusing to read precisely, but you can see that somewhere in the neighborhood of 1983 there's a marked change in the nature of the pressure decline.

Referring to Exhibit Number 28, we can see that during this period of time there have been relatively low fluid withdrawals from this portion of the field. And again, Exhibit 28 is a production plot of oil, water and gas from this township only. All wells within this township only derive from *Dwight's* database.

Beginning in 1984, there's a significant increase in fluid withdrawals from the reservoir.

Now, my next concentration of data points begins in about 1992, and you can see that there has been significant pressure decline in this portion of the reservoir caused by the increased fluid withdrawals. This is not a regression-analysis line through the data, it's simply a -- my interpretation of the type of decline that has occurred.

The last point plotted on this Exhibit 27 is significant to us, and it's far down in the right-hand corner of this graph. It's labeled as Savannah State Number 2, an average of two bottomhole pressures recorded -

- static bottomhole pressures recorded on our completion test of this well in August of 1996. 1174 pounds average, significantly below what we would have expected at this point in time in this reservoir.

And I contend that this is a result of excessive fluid withdrawals in this portion of the reservoir. As you recall, the Savannah State lease is near the edge of the reservoir. It is significantly impacted by excessive fluid withdrawals, and I submit that we have been damaged as a result of that.

Q. I direct your attention, Mr. Beamer, to Exhibits 29 and 30.

A. Twenty-nine and 30 are simply a tabulation of the record plotted in Exhibit 27. Exhibit 29 is a chronological record of the pressures taken for this township, and then Section 30 [*sic*], I simply have sorted the data by section and then by chronological order for each section. Again, these are the data points plotted in Exhibit Number 27.

Q. On behalf of Conoco, have you as a reservoir engineer examined the data in relation to the Joyce Federal spacing unit and what if any effect may have been caused on that spacing unit by the excessive production in the violation area just to the north?

A. Yes, I have.

Q. Let's turn to Exhibit 31 and have you show what the -- have you tell us what this plot shows.

A. I've prepared a plot in Exhibit 31 of -- comparing the Conoco production history in our Joyce Federal spacing unit, which is in the northwest of Section 32, compared to the immediately offsetting proration unit in southwest 29, operated by Yates Petroleum.

Conoco's production is shown in the heavy shaded line. The Yates production from the southwest section of 29 is shown with the line connected to the open triangles.

Again, we see that the Conoco production appeared to have established a -- roughly a 40-percent decline following the completion of the second well in that proration unit and was following that established decline for a period of about six or seven months.

The fourth well in the Yates proration unit, in the southwest of 29, was drilled and completed in mid-year 1995 and produced at excessive -- that proration unit then produced at excessive rates throughout the remainder of the year, at which time it began experiencing interference effects and began a very steep natural decline for that proration unit.

Early 1996, there is a departure noted in our 40-percent decline performance, which can be attributed to this interference effect from the offsetting proration unit.

Q. The change in decline goes from 40 percent to 75 percent?

A. Yes.

Q. Have you quantified the significance of that interference?

A. That relates to a difference in ultimate recovery of about 160,000 barrels of oil.

Q. Is it possible for Conoco to recoup those lost reserves?

A. From my analysis, the only way we could recoup that would be if we could somehow flatten our production rate decline to about 25 to 30 percent and hold that constant.

I don't see that as being practical, because to do that, first of all, would require a shut-in of the offsetting prorationing units for some period of six years or more, and there's no guarantee that we would ever get up to that flat a decline. I don't see it as being practical to ever recoup its lost production, just because of the operational practices.

Pressure decline in this reservoir limits our capacity to produce at higher rates.

Q. Have you estimated the number of months that Yates will have to be shutting in the production in the southwest quarter of Section 23 --

A. Of 29?

Q. I'm sorry, of 29, in order to make up the overproduction?

A. I did, and it's a very short time. That unit, in fact, by now could well be in compliance. But as of July the 1st, I estimated that a 2-1/2-month shut-in would bring that unit into compliance.

Q. Would that be a long enough period for Conoco to recoup any of the lost reserves?

A. No, it would not.

Q. Describe for me this pressure relationship in the reservoir and the impact of the advantage that Yates has gained by overproducing their spacing units at a point in time that that occurred in relation to what you're able to do now.

A. Our wells' producing capacity are related to the available pressure drop within our drainage area. Pressure drop is related to static reservoir pressure.

We have lost reservoir pressure due to the excessive production, which means that the available pressure drop to support our production is less than it could have been. That essentially is the primary problem. We cannot attain maximum producing rates that we might otherwise have had.

Q. What is your position as a reservoir engineer concerning Yates' request for higher allowables in North Dagger Draw?

A. My position is that yes, Yates does have some wells capable of producing at very high rates. I do contend that when additional straws are placed into these proration units where these high-rate wells exist, they will see very rapid interference effects, and I cannot believe that those rates would be sustained.

Q. What's your recommendation to the Commission?

A. My recommendation to the Commission is to take action and impose the proper penalties on the offending excessive-produced units, shut them in to bring them into compliance, and retain the existing pool rules.

Q. I direct your attention now to South Dagger Draw, and have you look at that exhibit set. Your first exhibit, I believe, is Number 8.

When we look at the package of exhibits that are in the binder --

A. Yes.

Q. -- starting with Exhibit 8 through 25, what are we seeing here, Mr. Beamer?

A. Okay, first of all, my preparation of documentation for South Dagger draw is not nearly as complete as I've done for North Dagger Draw.

These exhibits are production history plots taken from a *Dwight's* database of the available production history. The most recent history available is through April of 1996.

And it's simply a documentation of the actual oil, gas and water production history, plotted as daily average production rates versus time, for the given spacing units, which will relate, I believe, to our South Dagger Draw Exhibit Number 1.

In South Dagger Draw, as you recall, our proration units are 320-acre spacing, and in some cases you will see that they run north-south units versus east-west units.

Let's look at Exhibit 8, for instance, which covers the west half of Section 34, Township 20 South, Range 24 East. On our Exhibit 1, that would be this proration here, Mr. Weiss.

And as you can see, this exhibit was taken from a hearing presented in September of 1995, before this Yates Diamond well was even drilled, so that this exhibit does not include that well as a unit within the South Dagger Draw field. But in fact, it is completed in this formation and it will be included -- it will be pulled into this unit, if it hasn't already been done so. But that is the proration unit that I'm referring to in Exhibit 8.

And then in successive exhibits we're simply documenting the production history for each proration unit. I have identified only two proration units that I could see that have violated the existing pool rules of 1400 barrels of oil per day production limit for the 320-acre-spaced unit, one of which we can see in Exhibit Number 22, which is a Marathon-operated unit in the west half of Section 12 of 21 South, 23 East, which is this unit here. Four wells have been drilled on that unit.

You can see the stairstep nature of the production response when each well is brought on. These wells also tend to decline quite rapidly, and this unit, although it did -- it appears to have produced in excess of the allowable rate for a period of maybe five or six months, is now below that allowable rate and will soon be in compliance.

I thought I remembered -- Oh, I'm sorry, Exhibit 19 is also a proration unit which appears to have violated the allowable rate of 1400 barrels a day, beginning in early 1996. Again, this is a Marathon-operated unit in the west half of Section 2, on the west edge of the South Dagger Draw unit.

And again, very briefly, for one month period in mid-1995, a well was completed which brought that unit above the allowable, but rapidly declining below it. And then when they -- it looks like the fourth well in that unit was brought on, they have exceeded that allowable rate and have continued to do so through the production history available. It's obvious that this well is on a rapid decline -- or this unit is in a rapid decline. It will soon be in compliance.

Q. The source of the data for Exhibits 8 through 25 is in all instances *Dwight's*?

A. Yes.

Q. All right, sir. Let's turn to Exhibit 26.

A. Exhibit 26 is a similar performance history plot of the South Dagger Draw field, again at a common datum of 4000 feet subsea. And again, excuse me for not having this on production plot, but if you look back at Exhibit Number 25 -- Oh, my --

MR. CARR: Twenty-eight.

THE WITNESS: Twenty-eight. I'm sorry, look forward to Exhibit Number 28, which is the complete production history of the South Dagger field. We can see that there was a moderate decline in reservoir pressure through the period of early 1960s through mid- -- or through the mid-Seventies, at which time you can see there were very little fluid withdrawals taken from the field.

Beginning in 1990, of course, you can see the well count increasing rapidly, as well as the oil rate.

And then the more recent pressure history available in 1992 shows a significant pressure decline as a result of those added fluids withdrawn, again, just showing the nature, that this is a reservoir that is in hydraulic communication throughout the field, in my opinion.

Q. (By Mr. Kellahin) What do we see when we look at Exhibit 27? Twenty-seven was the tabulation?

A. Twenty-seven is the tabulation of the data presented in 26.

Q. Okay. What are your recommendations to the Commission with regard to Yates' proposal in South Dagger Draw?

A. We do not support the recommendation for higher allowables.

We believe that the current allowable is adequate to provide operators with significant production capacity to recover the reserves in these units within a reasonable period of time.

MR. KELLAHIN: That concludes my examination of Mr. Beamer.

We move the introduction of his Exhibits 10 through 31 in the North Dagger Draw case and Exhibits 8 through 28 in the South Dagger Draw case.

CHAIRMAN LEMAY: Those Exhibits will be entered into the record without objection.

Mr. Carr?

MR. CARR: Thank you, Mr. LeMay.

Mr. Beamer, I'll try not to extend this into your retirement.

CROSS-EXAMINATION

BY MR. CARR:

Q. I'd like to initially review with you just several things to be sure I again understand where we're in agreement and where we differ.

A. Yes.

Q. And during Mr. Patterson's testimony, we made some references to the testimony, presented in 1991, of Clyde Finley.

A. Okay.

Q. He was your predecessor, was he not, in Conoco who had responsibility for Dagger Draw?

A. He was our production engineer at handling the Dagger Draw area, yes, that's right.

Q. Back in 1991, Mr. Finley testified that in Dagger Draw wells we're draining less than 160 acres. Now, are we in agreement that that is still a true statement?

A. Yes.

Q. And he presented some data that said some were draining as little as 52 acres. I assume we're in agreement on that too. He didn't say every, he said some.

A. Yeah, that's reasonable.

Q. Mr. Finley also testified that based on his knowledge of the reservoir at that time, additional wells were acting almost independently of original wells on spacing units and that the new wells were in fact often better than the original well on a 160-acre tract. Do we disagree on that today?

A. I don't think so.

Q. And we have additional wells drilled on 160s that can come in and in fact produce better than the original well in the unit? He said that. Do you quarrel with that today?

A. I don't think I find quarrel with that.

Q. And I think we're in agreement on his statement that at very rapid rates we tend to get better water cuts. That's -- Those were his words, but --

A. I don't think anyone will object to that.

Q. Do you see -- Mr. Finley said he saw no evidence of the development of a secondary gas cap in the reservoir. Do you see that?

A. No, I don't think we see that.

Q. So on those points so far, we're still in accord?

A. Yes.

Q. He also stated that pressure data showed that with higher rates and increased withdrawals there was no negative impact on correlative rights. My understanding is, we disagree on that point today?

A. Well, following five years of production history, I think it's evident that there can be significant pressure decline, yes.

Q. Do we differ on our interpretations that we see a reservoir that is compartmentalized?

A. I think basically, our geologist agreed on the overall interpretation of the reservoir.

Q. And with the data that we have, do you know of any way we can determine the size or the location of the individual compartments within the reservoir?

A. Not to my knowledge.

Q. Okay. When I look -- Initially, you testified about Mr. Fant's Exhibit 15, the four --

A. Yes, sir.

Q. -- wells on a spacing unit. If I look at that exhibit, it appears to me that even with your decline curves on it, the wells that -- second and third wells still add about 250,000 additional barrels of oil --

A. Yes, sir.

Q. -- to the ultimate recovery from that unit --

A. Yes.

Q. -- is that correct?

A. Yes.

Q. And when you look at these, you see that the third and fourth wells may not perform quite as well as the earlier wells on the unit. Is that what this exhibit -- the way you put your decline curves on it, is that what that shows?

A. I'm saying that the third well has reserves, probably 160,000 barrels.

I'm saying the fourth well did not add significant reserves. It was an accelerated well -- acceleration recovery well.

Q. Did you compare these wells -- the location of these wells to where the are located in the formation?

A. No, I did not have at my disposal last evening to do that. I think, if I remember this area --

Q. Do you have a copy of Mr. Hardie's Exhibit Number 1, the isopach?

A. Yes. Exhibit Number 1?

Q. Yes, sir. If you look at Exhibit Number 1 and focus on the southwest of Section 29 --

A. Yes.

Q. -- you can see the well spots that are indicated in that tract, can you not?

A. Yes.

Q. And if we look at this tract, the Boyd 2 is the first well that was drilled; is that right?

A. That's that history that I'm not sure on.

Q. If the -- And you can correct this if you want, but if the wells were drilled, Boyd Number 2, Boyd Number 4, and then we drop down to the south and I think it's --

A. Aspden 1.

Q. -- Aspden 1 --

A. One.

Q. -- and then Aspden 2?

A. Yes, and I think the Aspden 2 was the last well drilled on that unit.

Q. It is in a thinner portion of the reservoir, is it not?

A. It is.

Q. And the last two wells, in fact, were drilled in thinner and poorer portions of the reservoir, are they not?

A. Not necessarily poorer. You can see their response from the fourth well drilled. It was a very good well. It did encounter what appears to be good reservoir rock, even though it was thinner.

Q. Okay. But it is a thinner portion of the reservoir?

A. Yes.

Q. All right. So the poorer wells, or the wells that contributed the least, were in the thinner part, no matter what was in that thinner section.

A. They're not necessarily poorer wells.

Q. But they contributed less overall than the original well?

A. They impacted our unit to a greater extent.

Q. Let's go now to your Exhibit Number 27. And I guess we need to again look at these in conjunction with 28.

A. And my Exhibit 27?

Q. Yes.

A. The pressure?

Q. And then the following exhibit, which shows the production curves.

A. Yes.

Q. Okay. If we look at Exhibit 27, this is the pressures you see in the North Dagger Draw Pool since 1962 through basically --

A. North Dagger Draw Pool, only within Township 19 South, 25 East.

Q. Okay. And so what we are looking at here is evidence that back in 1962 we were close to original reservoir pressure, about 3000 pounds?

A. Yes.

Q. And as we go forward, we get to a fairly steady decline until about 1984?

A. Yes.

Q. And then it drops and we have a cluster of points --

A. Yes.

Q. -- 1993 through 1995?

A. Yes.

Q. Now we're looking at the same properties, are we not, when we look at Exhibit Number 28?

A. Yes.

Q. And what you're showing on Exhibit 28 is the withdrawal, actually, from this area?

A. Yes.

Q. This Exhibit 28 is a logarithmic plot, is it not?

A. Yes.

Q. So when we look at this and we see the production take off, say, in 1984, and we compare that to the increases that we see, say, in 1989 through 1991 --

A. Uh-huh.

Q. -- actually from 1989 to 1991, we're seeing about ten times as much of an increase as we see in 1984; isn't that right?

A. Yes.

Q. It's just a function of the kind of plot we've utilized here; isn't that correct?

A. Yes.

Q. And so what we really see is a tremendous increase in production 1989, 1991, 1993, in that time frame; isn't that right?

A. Yes.

Q. Okay. And so what we see in the area that you've selected is a fairly steady decline, and then the points drop down here to the clusters shown in 1993 and 1995?

A. Yes.

Q. If you take just those points in 1993 and 1995, you really don't see that continuation of decline, do you?

A. There's not enough history.

Q. So we've just got a cluster of points around 2000 pounds, somewhere in that nature, slightly above?

A. Yes.

Q. And so that is really not markedly different than what we see when we look at Mr. Fant's Exhibit Number 16? We see a cluster of points in 1991, 1993 through 1995. Did you want to see it?

A. Well, they're probably, hopefully, the same pressure points, possibly taken to a different datum.

Q. But when we plot the decline and continue it off as if there's a big drop from 1982 and continue it forward -- really the plots up there are scattered in 1993 to 1995 -- it's hard to look at that alone and see if we're continuing to drop or if we're holding at about 2000 pounds?

A. From this data you cannot make that statement.

Q. We do have one point that's off the bottom of the chart. That's the Savannah State Number 2, is it not?

A. Yes.

Q. That was recently drilled by --

A. -- Conoco.

Q. -- Conoco?

A. Yes, sir.

Q. That point, I believe you indicated, showed the results of excessive fluid withdrawal; is that --

A. That's my interpretation.

Q. Now, if we take out Exhibit Number 8, if we take this one out -- this is Mr. Hardie's Exhibit Number 8 -- the Savannah Number 2 is the well in the upper left-hand corner of the block on this exhibit, at the bottom marked 29; is that not correct?

A. Yes.

Q. If we first compare that with Exhibit Number 1, isn't the Savannah Number 2 in a -- again, a thinner section than even the Savannah Number 1, the well immediately offsetting it to the east?

A. Yes.

Q. Now, we can't tell what the size of the pod might be in which the Savannah Number 2 is located, can we?

A. No.

Q. And we can't tell what other wells might be included with the Savannah Number 2 in that pod; is that right?

A. Not at this stage.

Q. It might be in a pod with the Savannah Number 1 to the east; isn't that right?

A. It could be, but Mr. Fant showed yesterday that that probably is draining a very small area of 29 acres.

Q. It might be in a pod with the Boyd 6, the offset due north; isn't that correct?

A. It could be, yes.

Q. Or it might be in a pod with the Joyce well, the immediate offsetting well to the west; isn't that right?

A. It could be.

Q. And it's experienced, I think you said, excessive fluid withdrawal?

A. It's experienced excessive pressure decline.

Q. If it's from the Boyd 6 -- that's the spacing unit due north, the well due north of it --

A. Uh-huh.

Q. -- the Yates well.

A. Yes.

Q. If we look at Exhibit Number 8, that's on a spacing unit that according to Mr. Hardie is going to recover only 1.26 times the reserves that are originally under it; isn't that right?

A. Yes.

Q. And if it's being drained by the Joyce well off to the west, that's from a unit that's operated by Conoco, I believe, that's going to produce 1.48 times what's under its tract; is that right?

A. Yes, yes.

Q. Bottom line is, we don't know why that well is actually at that low pressure, do we?

A. Well, we know that there have been fluids withdrawn. It is in communication with some portion of this reservoir.

Q. And we don't know where?

A. No.

Q. Okay. If we keep the rules exactly as they are, that 700-barrel-a-day allowable per 160, there are certain recently drilled wells that are going to have to be restricted; isn't that correct?

A. Yes, or cannot be drilled until they -- Yeah, that's correct.

Q. Does Conoco operate any of those recently drilled better wells that --

A. No.

MR. CARR: That's all I have.

CHAIRMAN LEMAY: Additional questions of the witness?

Yes, sir, Mr. Bruce?

EXAMINATION

BY MR. BRUCE:

Q. Mr. Beamer, there are -- I don't have a map in front of me. There are numerous well units which have undrilled locations on them because of one or two wells in that unit which are producing the allowables; is that correct?

A. Yes.

Q. Now, if these undrilled locations are offset by wells outside of that well unit, which are producing at the 700-barrel-a-day allowable, are those undrilled locations suffering drainage?

A. They could be, as a result of pressure decline, yes.

Q. How could you tell?

A. Pardon?

Q. How could you tell if they were suffering drainage?

A. Well, you drill the well and measure the bottomhole pressure, for one.

I mean, until the location is drilled you can't tell.

MR. BRUCE: Thanks.

CHAIRMAN LEMAY: Additional questions?

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Does Conoco use saltwater disposal wells that are injected into the formation?

A. No.

Q. None of your saltwater disposal wells inject into the --

A. None into the producing formation.

Our saltwater disposal goes into Devonian formation, which is significantly deeper than the producing horizon, yes.

Q. For those other saltwater disposal wells within the pools that are injecting into the formation, do you see a significant impact on the pressures or the recovery?

A. I quite honestly am not aware of any wells injecting into the producing formation, other than what Yates might be doing in their pilot waterflood project. At this moment, I can't think of a disposal well into the formation, into the producing formation.

Q. Can you speculate as to what impact that may have on the recovery?

A. It could be detrimental to the recovery. I think with the nature of this reservoir, with some high vugular developed systems, high vugs, high flow channels, that if you start injecting water into this reservoir you will cycle water from well to well, and you could ultimately damage the recovery. That's why we are not interested in doing any waterflood work in this area.

Q. Maybe you can help me put together a few of these exhibits.

A. Okay.

Q. Exhibit Number 8 and Exhibit 31.

A. I've got mine so out of order --

Q. Okay, 31 is the North Dagger Draw Cisco --

A. Okay, I'll see if I can find that one. Yes.

Q. Exhibit 31 indicates that it was declining at a 40-percent decline rate.

A. Yes.

Q. And then changed to a 75-percent decline rate.

A. Yes.

Q. Is that 40-percent decline rate typical of what should be in that particular area, in light of Exhibit 8?

A. In my opinion, it is, yes. That was the established production decline for this drainage area that these wells were draining, prior to interference.

Q. Okay, so you're saying that this 40-percent decline rate is typical of the other --

A. No.

Q. -- wells in that area?

A. No, I'm not. Each well and each proration unit will have its own particular decline, depending upon the thickness of the reservoir encountered, the porosity, permeability, the volume of oil within that drainage system, the capacity to produce.

It can become complicated, but each proration unit, each well, will develop its own specific performance decline.

Q. And each one will have a specific change in the rate of decline through time?

A. Probably, yes. Until they begin interfering with each other, and then at that time you typically will see the interfering wells all declining at the same rate.

Q. Now, I was just still under the impression that maybe 28 and 21 and 9 of the referenced portions of the Exhibit 8 may have actually benefitted because they're above 1.25.

A. It's possible. Again, the basic problem with volumetric estimates are the parameters that go into the volumetrics, and these are relative numbers. I guess -- Some of these areas have recovered more than what we say a 1.25 base number might be.

But again, for instance, in Section 21 -- I mean the reference to Section 21 on Exhibit 8 was one of the earlier producing proration units in this field area and did probably drain oil from the east prior to the discovery of this eastern area.

Q. So it works both ways?

A. It works both ways.

COMMISSIONER BAILEY: That's all the questions I have.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, this issue of interferences might be in the eyes of the beholder, it appears to me, from what I've heard here. And is there a definitive way to pin this down, pressure testing, multi-well pressure testing, interference testing? Does that give you an absolute look at this interference problem?

A. It could. We have not done that. We've relied strictly on an analysis of changing decline rates, you know, similar to what I've done, and I think Yates has done the same thing, looking at interference effects as indicated from the changing decline rates.

To my knowledge, Yates has not done pressure-interference tests, and I know that we have not.

Q. Would that work, do you think?

A. It's possible that it could work.

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

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Beamer, what do you think of the Yates fracture closure theory where you had 3000 pounds and then you start coming in at 2200 or 2300, the reason for that being that some of the fractures that were open have closed, and therefore you've kind of compartmentalized the reservoir at that point, because you've closed the fractures?

A. I don't think we support that theory. For one thing, we don't recognize that the reservoir is that significantly fractured. The vugular nature of it provides the flow capacity, in our opinion.

Q. Okay. In terms of -- You mentioned it would not be your opinion to -- or your recommendation, if you were going to stay with Conoco, to do any waterflooding in this field. How do you feel about injection of carbon dioxide?

A. Absolutely not. CO_2 is too expensive, and if a waterflood will cycle through this vugular system, we would end up cycling CO_2, and that is just too expensive to do.

I've been personally involved in a CO_2 project that failed, and it's not fun. Economically, it's difficult to approach a manager with an uneconomic CO_2

flood.

I would not ever propose a CO_2 project here.

Q. Do you have any suggestions for getting any more than -- what, 12 to 20 percent of the oil in place out of this reservoir?

A. At this time, no, I do not. It would be nice if Yates can prove that waterflooding does work.

My analysis of it is that there have been so many fluids withdrawn from this reservoir, to rebuild pressure to any degree would require so much water, we don't have enough water available to do it, and we did not think we had enough -- It would be too expensive for us to even begin developing the capacity required to inject.

Our estimate was, it would take 30,000 to 40,000 barrels of water per day to even begin to make an impact, and that's not considering the cyclic nature that would occur.

We think we would have rapid breakthrough of water.

Q. Since you're retiring, I can ask you to speculate a little bit here. Where is all this water leg?

If we see a relatively narrow band of dolomite that is the reservoir, we can't reach very far downdip southeast for it. Do we have to go along strike to get it?

A. That's something I'd rather have the geologist discuss. It's difficult to interpret where all this water is coming from, especially in the gas cap. Gas cap production comes with very high water volumes. That's difficult to --

Q. Would you agree that there is some water drive in the Indian Basin gas field itself?

A. I haven't looked at that production history to say.

My analysis of this unit tells me that if there is any influx, it is very limited. We might see it at the very tail end of this production history.

But at this time, there is no evidence of any significant pressure support.

Q. There seems to be watering out of wells in the Indian Basin field, is the reason why I mention that.

A. Okay, I'm not aware of that.

Q. Well, do you want to do any more speculation before we release you?

A. No, I'm speculating whether I'm going to make Midland in time.

CHAIRMAN LEMAY: Thank you very much, and good luck on your retirement. We appreciate your testimony.

Boy, that's hitting it pretty good, huh? Twelve o'clock.

Do you have any more witnesses?

MR. KELLAHIN: No, sir, that concludes our direct presentation, Mr. Chairman.

CHAIRMAN LEMAY: Would you rather sum it up before we go to lunch or --

MR. KELLAHIN: I think Mr. Carr may have something else to do here.

MR. CARR: Mr. LeMay, I'm going to request that I be permitted to recall Mr. Fant for some very brief rebuttal testimony.

CHAIRMAN LEMAY: Well, we can -- about how -- Do we have some more testimony that we're going to be hearing here?

I was just trying to gauge whether to come back from lunch or whether to --

MR. CARR: I might suggest that some people have some airline --

CHAIRMAN LEMAY: Do they?

MR. CARR: -- flights they're trying to make.

CHAIRMAN LEMAY: Well, let's keep going.

MR. CARR: Mr. Beamer is one of them.

CHAIRMAN LEMAY: Sure. Well, you bet. Let's just keep going and --

MR. KELLAHIN: It would be our preference to try to finish it up.

CHAIRMAN LEMAY: Let's wind it up.

MR. CARR: All right. At this time we would recall Mr. Fant.

ROBERT S. FANT,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Mr. Fant, I would request that you refer to what has been marked as Conoco Exhibit Number 6.

A. Okay.

Q. Can you identify that for us so we know what we're talking about?

A. It's a map, a plat entitled North Dagger Draw, Base Map Showing Allowable Violations.

Q. And on each of the tracts, there is a number of overproduction, is there not?

A. Yes, that's correct.

Q. And what does that number represent?

A. Basically it should represent the cumulative overproduction through -- as it was reported by them, through 7 of 1996, actually through the month of June, up until the beginning of July.

Q. Does it have any relationship to the recoverable reserves that were originally under that individual tract?

A. No.

Q. It's just simply a reflection of how much over the current 700-barrel-a-day allowable those individual parcels happen to be; is that right?

A. Yes. I'd point out one minor problem in their analysis. They used the wrong number of days for a few months in the later parts of this year, since February, and the northwest -- the tract number 1 on this one that they show with 3179 barrels of overproduction was at this time underproduced, and it still is underproduced, and so it's no longer in that status. So it would be a negative number also.

Q. All right. Now, let's -- But those are basically subject to some mathematical corrections --

A. Just math.

Q. -- units that are overproduced?

A. Yes.

Q. Those numbers shown are only numbers that show how much those units are overproduced, not what's under there, those tracts in the reservoir?

A. Yeah, they have nothing to do with recovery of oil; they simply have to do with what's been recovered as against some mythical number or some -- not a mythical number, but a number, 700 barrels a day.

Q. All right, let's go to Exhibit Number 7. Can you identify this?

A. Exhibit Number 7 is the volumetrics map, ϕh, presented by Mr. Hardie, for the same basic area that's shown in the previous one, with the overproduced area shaded in yellow.

Q. Mr. Hardie testified that he had used electric logs to help prepare this data; is that right?

A. Yes, he did.

Q. How reliable is that?

A. Well, in my experience, that was one of the first things I learned in this field, was that density neutron logs were incorrect. And Mr. Hardie in his direct testimony specifically said that imaging tools are much better.

Most of these wells do not have imaging logs. I've been working with some people to develop -- you know, mostly through their minds, not necessarily in my mind, but to utilize some artificial-intelligence technology to be able to predict what imaging logs would look like for a well where you didn't have imaging logs, you only had old ones.

But what the imaging logs -- one of the most powerful things they show is that sometimes the porosity -- the true porosity in the reservoir is sometimes two, sometimes even three times higher than what a regular density neutron log reads. Okay? And that's -- You know, and that makes sense with the amount of fluids that are being able to be withdrawn. And they furthermore show that in some instances -- and that two to three times can be for average over a well.

In some areas, you have places where it shows essentially zero -- the density neutron shows zero porosity. In other words, with a two-percent porosity cutoff, it would not be net pay, according to this map.

But with the imaging log or through the use of the artificial intelligence, you can see that oftentimes there is porosity there that is missed -- that secondary porosity that is missed by the density neutron tool, which primarily is designed to measure primary porosity. That's what Schlumberger -- Those are the people we happen to use. That's what they designed the tool to do.

And so within this map, in many different areas, there would be many different areas where ϕh is even missed when you use conventional logs. And it would be missed in the areas that have high porosity, and it would be missed in the areas that have low porosity. So you cannot use density neutron logs directly to predict ϕh per well. I do not believe you can do that.

Q. Wasn't the problem with the reliability of this log data discussed by Mr. Finley in 1991 in this hearing -- in the rule hearing for Dagger Draw?

A. Yes, Mr. Finley brought that up in 1991, that ϕh maps are quite -- not the ϕh map, but porosity values are quite suspect. In fact, he proposed just adding 6-percent porosity to whatever the density neutron reads. I don't believe that's an accurate method of doing it, because in some wells we see great secondary porosity, in other wells we don't see great secondary porosity. So you really need to look and try to predict what that secondary porosity is, and we are working on -- we have not finalized, but we are working on techniques to do that.

Q. Let's go now to Exhibit Number 8.

A. Okay.

Q. Would you identify that?

A. This is Conoco Exhibit Number 8, the volumetric-versus-decline-curve reserve comparison.

Q. Do you agree with how the factors that are depicted on this exhibit were actually calculated?

A. No, sir, I'm real concerned with one and that is how to calculate the water saturation. Conoco was concerned and said it's a tough thing to do, and I admit that.

Conoco based it upon a minus 4350 subsea water-oil contact, and as I remember, that Mr. Hardy characterized that as the point at which below that you don't get economic additions of oil, it's uneconomic essentially to perforate below that level.

That's one definition of an oil-water contact. I know at least three others, okay?

The point at which you begin to produce water is one that's bandied about for an oil-water contact. Well, that contact for this field would theoretically be somewhere above the field, because all wells produce water.

There's a point at which you absolutely stop producing oil.

And then there is another definition of oil-water contact that is a very scientific definition. It's the point at which you have zero capillary pressure. And the point at which you have zero capillary pressure is always the lowest, absolutely, mathematically the lowest of all of those calculations, of all of those oil-water contacts, the four different kinds that we just described. The one that's structurally lowest always is the one with zero capillary pressure.

And that is the only one, that definition, that point of zero capillary pressure is the only oil-water contact that can be used to predict the water saturation as a function of height above the oil-water contact. When you do that, when you predict water saturation as a function of height above the oil-water contact, that oil-water contact mathematically has to be the point of zero capillary pressure.

And it's sometimes 200 or 300 feet below the point where you stop making significant amounts of oil, because we have oil saturation in the reservoir at that point, so to have oil saturation in the reservoir at the point where we stop producing oil, that means we're -- residual oil saturation is right there. That point right there, by definition, has to have capillary pressure, so that's not a zero capillary pressure point.

So if you're not using the point of zero capillary pressure to reference those calculations from, they would be wrong. And what it would cause to happen is that the volumetric -- it would cause the water saturation to be predicted too high and the volumetric oil recovery within the unit to be predicted too low.

That's one of the problems that's occurring.

Q. Look at tract 18, right in the middle.

A. Tract 18, yes, sir.

Q. The bottom number, what does that bottom number indicate?

A. The 2.56?

Q. I'm sorry, I don't have the exhibit.

A. Oh, I'm sorry. This 2.56 here?

Q. There's an 1100 number. Do you know what that is?

A. The 1100 number is what Conoco is describing as the estimated ultimate recovery from decline-curve analysis.

Q. And then the bottom number?

A. And the bottom number in red, 2.56 is the ratio between the EUR reserve from decline-curve analysis and the volumetric reserves that they calculated.

Q. As you understand that 2.56 number, what does that show?

A. Conoco is saying here that this -- these two wells on this spacing unit will recover over 2.5 times what volumetric numbers would suggest that they can recover.

Q. Can you, by looking at this exhibit, tell us where that 2.5 times what was originally there is coming from?

A. Well, that -- Yeah, I looked at that, and it's really problematic, because you look to the north, that unit is at 2.32. To the northeast it's 1.81. Now, over to the right in 19 it's 1.2, which is what they said it should be, you know, 1.2, 1.25.

In all directions, everything is recovering basically as much or more than they said they were supposed to do. But they've already -- They're claiming by this that that's draining it from somewhere, but it doesn't look like anything around it is being drained.

Q. Mr. Fant, when you look at this exhibit and these numbers and look at the preceding exhibit and the calculations that have been utilized, in your opinion should these numbers be relied on as depicting what's actually going on in the reservoir?

A. No, sir, the porosity is wrong, the h is wrong, the saturations are wrong.

Basically, the components that went into the analysis of volumetrically recoverable reserves, the basic components that went into that, every one of them is very suspect.

Q. Let's go to Yates Exhibit 24, the curve on the Polo well.

A. Yes.

Q. Mr. Hardie indicated he could see a decline. Do you?

A. Well, I see that the well was stabilizing over about the last five days at about 1300 barrels a day.

Mr. Kellahin had talked to me before that, you know, has the stabilized? He continually asked me, had one stabilized? Well, this one was beginning to. It was producing -- and I'll call your attention to this -- it was producing approximately 3300 barrels of liquid per day. The pressure in the reservoir and the pump could combine to move 3300 barrels of liquid to the surface on -- when we went to turn the well off.

Now, they have said that we had -- and Mr. Beamer used the words "pressure decline from offset wells". They said that the pressure had declined in this.

I want to call your attention to the fact that when we got the well producing again, it's producing 33- -- it dropped -- it was producing 2800 barrels of oil and about 600 barrels of water, which is 3400 barrels of liquid.

In other words, the pressure in the reservoir was delivering exactly the same amount of liquid into this well. And we were -- And it has to be going against this same pressure, because if it wasn't going in the same pressure in the wellbore, that pump wouldn't be able to lift that much. This pump is not supposed to be able to lift this much as it is. It's because there's a very high fluid level in this well.

The fluid level, when we turned it on -- or the bottomhole producing pressure, when we turned it back on, is the same as it was before. The reservoir pressure essentially has to be the same as it was before, because we're moving the same amount of liquid, we're moving the same amount of fluid out of this reservoir.

Q. Mr. Fant, is it fair to say when you look at this graph you don't see a decline?

A. Absolutely not, when you analyze the total fluid.

Q. Do you see potential damage to that well?

A. It can really only be explained as damage to the well. It falls back to my statement yesterday that you must take into account all of the data on everything.

MR. CARR: That concludes my redirect of Mr. Fant.

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: Any other questions of the witness?

Commissioner Bailey?

COMMISSIONER BAILEY: No.

CHAIRMAN LEMAY: Commissioner Weiss?

COMMISSIONER WEISS: I have no questions.

CHAIRMAN LEMAY: Nor do I. Thank you.

Are we ready to sum it up? Are there any other witnesses or --

MR. KELLAHIN: I have a point of procedure, Mr. Chairman.

CHAIRMAN LEMAY: Yes.

MR. KELLAHIN: Mr. Carr announced at the beginning of the hearing that he was representing Nearburg Exploration Company --

CHAIRMAN LEMAY: Yes.

MR. KELLAHIN: -- if I remember right.

I have received a copy of a letter written to the Commission from Mr. Bob Shelton on behalf of Nearburg, in which he asks you to take his comments and recommendations into consideration at this hearing. Nearburg is a major violator of the overproduction. And I was curious of Mr. Carr if he intends to submit Mr. Shelton's letter into the record of this case.

MR. CARR: No, I do not. I do not.

MR. KELLAHIN: Then I propose to do so, Mr. Chairman.

CHAIRMAN LEMAY: Okay, thank you. My recollection of that letter, they were asking for a longer period to make up the overproduction, wasn't it?

MR. CARR: And I would note that this is not sworn testimony, and if it is taken into -- it can't actually as such be considered; it is nothing more than a comment.

CHAIRMAN LEMAY: Nothing more than what?

MR. CARR: Jut a comment.

CHAIRMAN LEMAY: A comment.

MR. KELLAHIN: Mr. Chairman, these are admissions by an opponent in this case. It's an adjudication by you. It's a major violator, and I think his statements in here are very relevant and very important for your consideration.

CHAIRMAN LEMAY: We'll weigh the letter accordingly.

Okay, anything else, Mr. Kellahin?

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: Any reason to leave the record open for any additional information on this case?

MR. KELLAHIN: I don't know if there's -- There's other participants in the hearing, Mr. Chairman. I don't know if they have statements or requests from you.

CHAIRMAN LEMAY: Are you all going to make a statement, Jim?

MR. BRUCE: Yes, sir, I will, but it will be about 20 seconds long.

CHAIRMAN LEMAY: Okay, anyone else going to be giving a statement?

MR. KENDRICK: (Shakes head)

CHAIRMAN LEMAY: I think the show is still yours, so --

MR. KELLAHIN: All right.

CHAIRMAN LEMAY: -- are there any reasons you want to leave the record open?

MR. KELLAHIN: Not from our position, Mr. Chairman.

CHAIRMAN LEMAY: Okay. Do you want anything else for the record to consider?

Okay. Well, we'll close it and take it under consideration after you sum it up.

MR. BRUCE: Mr. Chairman, just on behalf of Unit Petroleum, I'd like to state that Unit supports an increase in the allowable in the North Dagger Draw as the only way to protect its correlative rights. It owns working interest in well units which are now allowable-restricted, and without an allowable increase it will be unable to drill four wells per 160-acre unit for some time.

Without drilling those additional wells, Unit believes it will suffer drainage from wells on offsetting leases in which it has no interest, and Unit further believes the data presented yesterday and today supports the allowable increase.

CHAIRMAN LEMAY: Thank you. Additional statements in the case?

Do you all want to sum it up?

MR. KELLAHIN: Yes, sir.

CHAIRMAN LEMAY: That's it.

MR. KELLAHIN: Do you want me to go first?

MR. CARR: (Nods)

MR. KELLAHIN: Mr. Chairman, let me comment on Mr. Shelton's letter on behalf of Nearburg. I would ask that at the appropriate time you read it in its entirety.

Nearburg is representing to you their belief that they consider this reservoir is pressure-connected throughout the known producing area, and they are attempting to form an objective opinion on the appropriate method for producing and cutting back their -- this high-capacity reservoir.

It goes on and says, Nearburg has no objection to the allowable staying at 700 barrels a day in North Dagger Draw.

He does make a misstatement with regards to the Conoco overproduction in the northeast of 32. I think he has misstated. That's the Mewbourne tract, and it should be the northwest of 33. I think he simply misplotted the information. There's certainly no indication in this record by any of the parties that the northeast of 32 is overproduced.

He asks for an extension beyond the 18 months to make up the overproduction. He's asking for a 24-month period.

And I think the last paragraph, perhaps, sums up this case as good as can be summed up. He says, Certainly with new technology and ever-increasing knowledge of reserve behavior, reservoir behavior, regulations must keep pace to keep our industry viable. Likewise, once set, production allowables must be honored, or the Oil

Conservation Division mandate to protect correlative rights and prevent waste becomes impossible, and responsible operators who obey the regulations are severely penalized for their honest. Such in lies Conoco's dilemma.

The rules and regulations of the Division are very clear and unambiguous. Illegal oil is defined by the Oil Conservation rules to mean crude petroleum produced from a well in excess of the allowables fixed by the Division, and the sale, purchase, acquisition or the transporting, refining, processing or handling in any way of that oil is prohibited. Illegal oil cannot be transported from the lease tanks or sold.

In North Dagger Draw, the Division has adopted all allowables in this pool in order to manage and regulate production in a very competitive reservoir and to assure that all operators are playing by the same rules so that we will be afforded the opportunity to protect our correlative rights. Those rules were fixed by the Division, and they were established at 700 barrels of oil a day.

It is Conoco's position that Yates has ignored these rules and regulations and, in our opinion, created a pressure differential to their spacing units, a greater one than would have occurred had they complied with the regulatory producing rates that were set by the Division. That unfair competitive advantage has taken advantage of us.

It is our technical conclusion that the excess pressure depletion of the reservoir cannot be restored, and Yates has caused permanent damage to the correlative rights of Conoco as an operator who has complied.

My good friend Mr. Carr is very fond of borrowing a phrase that my dad used to quote to this Commission years ago, and my dad, like Mr. Carr, always opened his closing statements by saying that the Oil Conservation Commission is a creature of statute, you're empowered and limited to protect correlative rights and prevent waste, and I'm sure Mr. Carr is going to tell you that once again, and he's going to ask you to do your duty to protect the correlative rights of Yates.

And what right has Yates asserted? They're asserting the right to unrestricted capacity allowables in North Dagger Draw. They're asserting the right to intentionally disregard your rules and to overproduce their producing allowables and to be excused and forgiven for that overproduction. They're exercising their correlative right, they contend, to resort to unregulated competitive practices in the reservoir.

The right to produce the oil is established by our rules and regulations, and there's a correct way to go about changing those rules, and then there's the wrong way.

The correct way to do this in this pool was done in 1991, when Conoco did it the right way. They brought their data into this regulatory body, got those rules changed prospectively, and then everybody is afforded a level playing field, and they produced at the higher rates. That is how we play fair.

What has occurred here is that Yates has taken information that they have had for almost a year and, to their advantage, has produced production from the pool, and after doing that, now contends it's wasteful to have them restricted.

Here's the real problem. The rules were flexible. They were generous to the operators in a very complicated reservoir. That flexibility afforded them the opportunity to make the choice to drill as many as four wells in a 160-acre spacing unit. But with that flexibility was the responsibility to drill their wells and produce them in a sequence that they abided by the top oil limit.

Yates chose not to do that. They drilled more wells than they needed in order to produce that allowable. And once they started doing that, as you can see from Mr. Shelton's letter, Nearburg responded, the flexibility of the rule becomes a problem and that now we in fact have unregulated competition occurring.

The fault is not Conoco's, the fault is not this Commission's, the fault is not Mr. Gum's. The fault is Yates, and they bear us the responsibility and the obligation to solve this problem.

I think it's unfair for them to ask us to forgive their overproduction. And the excuse is that now that they have drilled high-capacity wells, that if you restrict them, there may be some drop in the oil cut. How dare they put us in that predicament?

We've seen from the testimony of our witnesses that it's become a point in time in the reservoir where the violation and impairment of our correlative rights might not be cured. It's also a problem for us to figure out how are we going to balance the playing field, and what penalties are imposed upon Yates for the activity they have engaged in?

Let's not lose sight of the fact that Yates, by their action, has pushed this agency into a corner, they have challenged the regulatory integrity of the compliance methods of this Division. And historically this agency has not had to be policemen. We have established rules and afford the opportunity to all the players to be self-policing and to comply. Fortunately, that has worked most often.

I've been practicing before you for more than 25 years. I am unaware of a violation to this extent and to this magnitude.

Whatever you do with regards to this case is going to send a regulatory message to the State of New Mexico and to all operators. And we can niggle over whether or not there is wasteful consequences to asking Yates to reduce their production. If you look at the numbers, there's a 7- or 8-percent differential. Yates has put a price on it. They say it's $7 million that we're somehow not going to get to keep. The problem is that the gross profit is $20 million. And how do we do that? We're not very well equipped as regulators to manage that.

It would be wonderful to take the profit out of the violation and to ask Yates to turn over the profits from the illegal oil, and let's put it in the State of New Mexico. If I had the ability to do that, I would suggest that would be a marvelous solution.

If we had the ability to let these wells produce at capacity, wouldn't that be wonderful? Isn't it an incredible disappointment that they didn't unitize this wonderful asset, this marvelous resource? And I don't know how you fix it. I'm not sure anybody knows. But wouldn't it be neat if you could let these wells produce at capacity and yet take that profitability and share it to those people that are being drained and affected by the advantage that they have sought for themselves and denied to us?

It is truly beyond comprehension to suggest that Yates is going to be excused or forgiven or the violation should be ignored. And so that's one issue for you to grapple with.

The other issue is, what are we going to do about the rules in the future? Yates has attempted to link them together, because if you link them it gives you a wonderful way out of the problem.

I suggest to you that Mr. Stogner's proposal to create an industry committee is a wonderful solution to this problem. I think it's an accepted practice, it is a marvelous idea.

I know Mr. Carr is going to tell you that you're abandoning your regulatory responsibilities and that you ought to sit here in a day and a half and figure this out and come up with the magic number, and we all go ahead.

But I think the responsibility for this reservoir ought to be for you to oversee its management, but to put the problem right back on the plate of the party that put it there, make these operators come together in a controlled committee activity and make them do what Mr. Stogner suggested. Let's get these brains together and in a matter of weeks or months let's put some real technical resources into solving the problem.

How dare they expect you to come here in a day and a half, assume all this information, spend your time and effort trying to figure out the technical aspects of this and then decide what's going to happen to us from here forward?

I think it is a manifest obligation of you to designate the committee operators to form this work study. I think it's a marvelous solution. We support having you do that.

Mr. Carr is certain to ask you to do your duty. Your duty is to control and manage the competitive reservoir that's occurring here. Unfortunately, despite your best efforts and your best intentions, Yates has broken the faith. They've breached their integrity with this Commission, and now they seek to have you forgive it, and we ask that you not do so.

We would ask that you modify the Examiner order to the extent that these wells be immediately shut in, until all their overproduction is made up.

The only evidence presented to you that that is somehow wrong is the contention by Mr. Fant that that Pogo well can't handle it. Now, you heard Mr. Hardie at length describe to you the fact that he had a well that was shut in for more than 18 months. He was able to restore it to production. It subsequently went on a steep decline, simply because it had been drained by another nearby well.

But why should you have to decide whether these wells can bear a shut-in? Why should you decide and assume to do the engineering work to decide how to cycle these wells? Maybe we ought to just shut these wells in and let these operators get together and figure out how they're going to fix the problem Yates made.

We're in a difficult situation. We are a minor player in South Dagger Draw. We are not a major operator in North Dagger Draw. And we are the only operator coming forward to show you any type of technical presentation about the reservoir, other than the offender. It shouldn't be our responsibility to police the pool rules, it shouldn't be our responsibility to come here.

This is Yates' responsibility. They made this problem, and it's their obligation, it is their burden of proof to satisfy you beyond any reasonable doubt that you can increase the rules as they've requested. I've gone away with considerable doubt today. I hope that you have too. And if they have not satisfied you, then let's not do what they've asked to do.

We ask that you deny the request and that you affirm the Examiner Order with the modification that these wells be shut in.

Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Mr. Kellahin.

Mr. Carr?

MR. CARR: Mr. Chairman, Mr. Kellahin has warned you that I may tell you to do your duty, and he's right. And he's trying to head that off because when we examine what your duty is in the context of this case, his case simply goes away. And so I'm going to warn you that in a few minutes I'm going to ask you to do your duty.

But beforehand, there are some other things that I think we ought to discuss, and I'm going to try and do it, unlike my friend Mr. Kellahin, I'm not going to have a miter on one moment and throwing lightening bolts the other, because I think this is too serious. And I think it goes beyond collateral issues of sending signals to the industry or whether or not we should unitize, because we have some very serious things before you, and things I believe you really do need to decide.

I also think it's important at the outset of my closing to address the statement filed by Nearburg. That statement stands before you in the same posture as the statement made by Mr. Bruce. It's an expression of an opinion of an operator. It was not sworn testimony, and Mr. Kellahin's review of it does not change it or elevate it in any way.

I think when we look at the Dagger Draw North and

South, that no one in this room doubts that this is an extremely complicated reservoir, and that's the reason that for the last 25 years the operators and this Division have been repeatedly involved with trying to figure out what must be done with this reservoir. And you have had an ongoing involvement in that process, and you haven't just passed your responsibility away to the operators in the pool.

And we're still learning about the reservoir and how we can effectively produce the reserves from the pool. If we go back through the history of this reservoir, we can see from the days of Roger Hanks or the days of the Conoco application in 1991, that there has been real concern that the reservoir needs to be produced without restriction. That's what Roger Hanks asked, that's what you said he could do. That's what Conoco asked for in 1991, and that's what you said they could do.

And we stand before you today asking you to tell us exactly what you told Roger Hanks and what you told Conoco, that yes, you recognize waste results from restricted wells, yes, there is not a serious correlative rights problem, if there's one at all, and that we must prevent waste, and yes, the allowables must go up.

There are two issues before you. One is the enforcement of your rules, and the other one concerns very simply the waste of oil.

If we look at the question and the facts surrounding the overproduction in this pool, first, foremost and always, we admit we are overproduced. And when you look at that, instead of just charging in as Mr. Kellahin would like for you to, we'd like to put it in some context.

And we're not trying to say that it was wrong for Conoco or Mewbourne or Nearburg or anyone else to have wells that initially overproduced and through natural decline processes came back in line, but that is a fact of how the wells in this reservoir perform. And that's what's happened. It happened to ours, and last year it didn't happen to ours, and we didn't know what to do.

Now, we can speculate and say, Well, Mr. Gum said this, or we said this, and they should have said something, we should have reached an agreement. Bottom line is, we talked to them about it, you didn't know what to do, we did not know what to do. We continued to produce the wells, we continued to gather data, and we got into a situation where we're very substantially overproduced.

And we've come before you and we have done, I think, what any operator does in this situation. I mean, we're not hiding the ball. We're overproduced. And we've told you that as bad as we think what came out of the

Examiner Order August 14th was, we'll do that. And if you change it because you see that something else must be done, we will do that, and that we're overproduced, and it's your jurisdictional area to tell us what to do, and we will do it. But just because that's happened and just because that's going on, we can't ignore what's going on in the reservoir.

Now, Mr. Kellahin comes in, and you've heard him, You should have been here ahead of the fact, you should have come in here and changed the rules before the wells we thought were going to decline didn't, you should have formed an operator committee and you didn't even go out and ask.

You remember the Yates-Nearburg war, as Mr. Kellahin characterized it. How wise do you think it would have been to go over to Nearburg and say, Don't you think we ought to produce our wells higher so we can gather some data? I mean, those are not realistic. They're not realistic things that we could have done.

And then to say that, Well, if we'd gotten in here a year ago, maybe we could have increased the allowables and not overproduced, is an absolute ludicrous position to take.

When we came here in May, we presented to the Division data on 280 wells, data that went back over 25 years, and we were told we were premature. Well, I will tell you, if we were found to be premature in May of 1996, we would have been premature in your judgment in May of 1995.

So that's how we got to this point. We're here before you telling you we are going to straighten it out as you tell us to, not as we tell you to, because you are the Commission. It's not always lop everything back to the operators, and we will deal with that problem as you want us to and you direct us to.

But we have a very much more important question before you here today, and that question involves the prevention of the waste of oil. I think an awful lot of the technical data is not in dispute. The pool produces large volumes of water, and we all agree that you have a higher oil cut at higher production rates. That's one of the heart-and-soul facts before you, is, you retire to resolve and address the issues presented here.

We've said that the producing rates are efficient and result in lower gas-oil ratios in 75 percent of the wells. We've shown you that most of the oil that is produced from additional wells in spacing units which we're drilling -- and I think everyone agrees and many areas need to be drilled -- most of that is new oil, oil that otherwise, without the wells, would be wasted. And we ask for a depth bracket allowable that is increased very substantially.

We'd have been laughed out of here in 1991 if we had ever suggested that we would have needed to go above 700 barrels a day to a number like 4000 barrels a day. But we hadn't drilled a well then that initial potentials on the well were 2460-some barrels a day. We didn't have wells, one potentially a four on a spacing unit, that stabilized like our Polo well at 1300 barrels of oil per day.

Now, when we talked with the expert witnesses for Conoco, they admit that if we stay at 700 a day, well, we're not going to be producing those wells as efficiently as they can produce theirs at 700, because we can't pump them off. So we have a legitimate waste issue.

And to sit here and suggest that we should walk into a room and try and agree with Conoco and the Nearburgs as to what could be done, and then that -- we're going to come forward with the unanimous recommendation, and we're sitting in that room with wells like we have, and everybody else who was not restricted at 700 barrels a day wants to stay there, we're walking into a situation where we're saying, don't declare war, as you have, on the fact that we have finally been able to figure out how to truly produce the reserves out of this reservoir, and apparently you have not.

We submit to you that you can't dispute on the facts before you, and that's what you must look at. You don't go like the Examiner and go rambling through the files in old cases and try and build another case, a third case for you to consider. You look at what we've presented and what they have presented. And on the facts before you, I think you must conclude that at higher rates we're more efficient, that at higher rates waste does not occur.

As to the correlative rights, we've shown you that based on our review, interference occurs less than five percent of the time and that it only impacts one percent of the reserves in the reservoir. And that's because of compartmentalization reservoir, it may be because fractures close, as we believe, or it may be because of other factors within the reservoir, but compartmentalization is not an issue here. We agree on that. And because of that, the impact on correlative rights is small if at all.

And it's very much today like it was when Clyde Finley, Conoco's expert witness in 1991, came before you and said he didn't see a correlative-rights problem by going to 700 a day so they could produce the best wells in the pool without restriction.

I am going to tell you that it's time for you to do your duty. And I want to tell you that when I come before you, I come before you ever mindful of the fact that I'm a lawyer and ever mindful of the fact that I come always before you with a group of lawyers. And we do, I will tell you, sense that -- and maybe rightly so -- we're generally viewed as a kind of unnecessary nuisance that you have to contend with. But there is a reason that we're here.

We're not here -- and I think you can tell from our depth cross-examination of technical witnesses -- we're not here to get the technical issues before you or to resolve those. We're here to remind you why you're here and to bring cases before you in the format that the Legislature said they had to come before you so you could decide them properly.

Mr. Hardie says, Mr. LeMay, Mr. Weiss, Ms. Bailey, you need to balance correlative rights and waste. And I will tell you that that is absolutely, absolutely wrong.

Jason Kellahin said, and I quote, This Division is a creature of statue whose powers are expressly defined and limited. He thought that was important. So do I. Because when you come in here to decide a case like this, you have to go back to the law, because you're a creature of statute. You're here because the Legislature gave you very explicit and very important responsibilities, and your jurisdiction is based on waste, and then it is based on correlative rights.

Look at the definition of the terms. Waste is defined in numerous paragraphs. But correlative rights is defined as the opportunity to produce your share without causing waste. That says to this Commission, you can't protect correlative rights when you cause waste by doing it. You must look at the waste issue first. If you fail on the waste issue, you fail completely. That's what you have to look at.

It's not a balancing act, because when you focus on correlative rights, when you push that above, in your consideration, a waste issue, you're regulating fields not on what they can do, not on what the best operator in the pool can do with the best well in the pool; you're tying the production of reserves from the reservoir to what lesser operators do with lesser properties, and you cause waste. And that's why in our scheme, waste is the primary thing you are directed to prevent.

And you have to do something. It is not the function, I would submit, of a regulatory body to, when the questions get difficult, to say, Mr. Nearburg, Mr. Conoco, Mr. Yates, you go work it out and come back in 18 months. That's not the function of an agency of this nature.

You're here to decide cases, not just hear them. You're here to act to prevent waste.

And you can't duck that responsibility because the issue is complicated. When you do that, you're doing just what the Examiner did. And when the Examiner said, I'm not going to decide this, you're premature, 25 years, 280 wells, every piece of data you can give us, but you're premature, and instead I'm going to pass it off to a committee.

That's not a failure of the Examiner to do his job, it's a refusal to do his job. Because you're here to decide cases, to render decisions on the evidence that is presented to you. And that's what we're asking you to do.

I think while you're asked to put meaning in your rules, and I think that's important, you've got to ask yourself some important questions, and when I opened yesterday I said there's some important questions before you.

But when you retire to decide what you're going to do to prevent waste and carry out your statutory duty, I submit there's one question each of you must ask yourself, and that is, How much waste is enough? How much waste is okay? And you've got to weigh that question, how much waste is enough, against your duties as Commissioners who are charged by the Legislature to prevent waste, and the facts of this case.

Ms. Bailey, on these facts, when you retire, I think you have to ask yourself, On the facts of this case, how much waste is okay, how much oil should not be recovered because of Commission order practices in the absolutely most prolific oilfield in this state, how much waste is okay?

You must ask yourself, How much royalty should the royalty owners in these properties, including the State of New Mexico, be denied because of Commission order practices which cause waste today, which caused them last year and, if not changed, will cause them in the future? I think you must ask, How much waste is okay? How much should each royalty owner in these properties, including the State, be asked to contribute because some operators have overproduced wells?

Mr. Weiss, I think when you consider this case you must ask yourself, On these facts, how much waste is all right? And are we doing our duty? Should not operators be able to come in here and present to this body new engineering, technical information?

The Supreme Court of New Mexico found this body has special expertise, special engineering expertise and competence. And is it not fair for us to be able to come in here, bring our technical data to you and have you review it and bring your expertise to bear on that? Isn't it reasonable to expect that to happen, instead of being told, Go back, meet somewhere in Midland and work it out for 18 months?

Because what happens when that occurs is that we meet for 18 months while in this reservoir Rome burns. Now, Rome, I will admit, in this case is located in Artesia, New Mexico.

But I will -- because we have the best wells, we have the properties that are going to be harmed. But it isn't that isolated, because as Rome burns, revenues fail to find their way back to the State of New Mexico, to other working interest owners and to the royalty interest owners. How much waste is all right?

Mr. LeMay, how much waste is all right? Can you just send the problem away to a committee, whose membership you don't even probably intend to appoint, and sit back and wait for 18 months until the questions that are presented to you here today become moot with the passage of time, until terrible reservoir damage has occurred?

I don't know how much waste it's proper to expect because some operators are overproduced, but I will tell you, when we deal with questions of this nature, we really believe we can bring them to you and they can be resolved.

If the only way we handle a difficult question is just to lop that back to the industry, why would we need an Oil Commission? We won't come back with an agreement 18 months from now, but we will have a waste we can document from here to Midland and back.

I submit to you that you can't refuse to do your duty here that you have to address the issues. And when you do it, do what you will with the overproduction. If we stand on the August 14 Order, so be it. And on if we make it up, we propose the only reasonable thing to do is to make that up under the 700-barrel-a-day original allowable for the pool. That will give everyone an incentive to get their properties back in line before they can take advantage of the allowable that is appropriate based on the technical data that's before you.

That's how we recommend it be handled. We'll live with whatever you tell us.

But we submit that looking forward, looking at the wells that are going to be drilled in the next year, the wells that have been drilled in the last year, allowables simply must be increased. They've got to be substantially increased.

If you can't go the whole way with us, a substantial increase is clearly warranted from the technical data before you, because if not, you side with Conoco. And Conoco is basically making an attack through a regulatory process on the good wells in the pool. They don't have them, we do. And they want them curtailed and shut in.

When you increase the allowables and increase them substantially, you will have met your statutory obligation, you'll be acting to prevent waste. And I would tell you that only by doing that do I believe that when you look back on this case and your tenure as a member of this Commission, and when you are asked why you were there, what did you do to prevent waste, you will be able to answer, While I was there, any waste was too much.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Before you all go, I need to just kind of get my fellow commissioners and --

(Off the record)

CHAIRMAN LEMAY: Okay, before we close, recognizing Yates has voluntarily kept their production within the allowables that were dictated by the August 15th Examiner order, we would like to lift the stay, we will lift the stay, and until we get an order out from the Commission those allowables will remain in effect.

MR. CARR: And we will keep our wells at 350.

CHAIRMAN LEMAY: Yeah, at 350 --

MR. CARR: Yes.

CHAIRMAN LEMAY: -- until we get an order out.

Thank you very much, gentlemen. Appreciate it.
Is there anything else in the case?
MR. KELLAHIN: Can you issue a letter so that operators that perhaps weren't here will know --
CHAIRMAN LEMAY: Certainly will.
MR. KELLAHIN: -- the compliance requirements?
CHAIRMAN LEMAY: Yeah, we will do that.
Take the case under advisement. Thank you.
(Thereupon, these proceedings were concluded at 12:51 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 II) 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 28th, 1996.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998