STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:) CASE NO. 10,994

APPLICATION OF ENSERCH EXPLORATION, INC.)

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: JIM MORROW, Hearing Examiner

July 21, 1994

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Division on Thursday, July 21, 1994, at Morgan Hall, State Land Office Building, 310 Old Santa Fe Trail, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

July 21, 1994
Examiner Hearing
CASE NO. 10,994

* * *

A P P E A R A N C E S

FOR THE DIVISION:

RAND L. CARROLL
Attorney at Law
Legal Counsel to the Division
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Santa Fe, New Mexico 87504

FOR THE APPLICANT:

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By: TANYA M. TRUJILLO

* * *

WHEREUPON, the following proceedings were had at 9:00 a.m.:

EXAMINER MORROW: Call Case 10,994.

This case was heard two weeks ago [*sic*], and I understand it was continued for the purpose of additional notice or re-advertisement.

So if there's no one here to appear and offer anything in this case, it will then be taken under advisement.

MS. TRUJILLO: I'm sorry, Mr. Examiner, what case number was that?

EXAMINER MORROW: 10,994.

MS. TRUJILLO: I do have something.

EXAMINER MORROW: Okay.

MR. CARROLL: That's the Application of Enserch Exploration, Inc, for the assignment of a special depth bracket oil allowable, Roosevelt County, New Mexico.

MS. TRUJILLO: Mr. Examiner, my name is Tanya Trujillo from the law firm Campbell, Carr, Berge and Sheridan.

I enter an appearance today on behalf of the Applicant.

EXAMINER MORROW: Go ahead, Ms. Trujillo.

MS. TRUJILLO: Mr. Examiner, as evidenced, this case was heard on June 23rd. It was continued at that time because it was discovered that one party, Bledsoe Petroleum Corporation, was not given notice at that time.

Today I submit a supplemental affidavit signed by William F. Carr, indicating that notice was provided to Phillips Petroleum Corporation.

And at the June 23rd hearing Mr. Stogner, the Hearing Examiner that day, requested that a proposed order be submitted, and I submit a proposed order today.

MR. CARROLL: Ms. Trujillo, apparently you haven't heard anything from Bledsoe?

MS. TRUJILLO: Oh, yes, they received -- They received the notice.

MR. CARROLL: They signed for it, but haven't contacted you?

MS. TRUJILLO: No, not to my knowledge.

EXAMINER MORROW: Anything further?

MS. TRUJILLO: No, nothing further.

EXAMINER MORROW: All right, Case 10,994 will be taken under advisement.

(Thereupon, these proceedings were concluded at 9:03 a.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 10994, heard by me on July 21 1994.

_________________ Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL July 22, 1994.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1994

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:	)	CASE NO. 10,994
APPLICATION OF ENSERCH EXPLORATION, INC.	)	

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

June 23, 1994

Santa Fe, New Mexico

JUN 27 1994

This matter came on for hearing before the Oil Conservation Division on Thursday, June 23, 1994, at Morgan Hall, State Land Office Building, 310 Old Santa Fe Trail, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

June 23, 1994
Examiner Hearing
CASE NO. 10,994

* * *

E X H I B I T S

APPLICANT'S:

	Identified	Admitted
Exhibit 1	11	16
Exhibit 2	11	16
Exhibit 3	12	16
Exhibit 4	13	16
Exhibit 5	34	48
Exhibit 6	38	48
Exhibit 7	41	48
Exhibit 8	42	48
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Exhibit 10	45	48
Exhibit 11	47	48
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* * *

PHILLIPS:

	Identified	Admitted
Exhibit 1	79	88
Exhibit 2	85	88
Exhibit 3	86	88
Exhibit 4	98	117
Exhibit 5	99	117
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Exhibit 7	103	117
Exhibit 8	105	117
Exhibit 9	108	117
Exhibit 10	110	117
Exhibit 11	111	117
Exhibit 12	112	117

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A P P E A R A N C E S

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By: WILLIAM F. CARR

FOR PHILLIPS PETROLEUM COMPANY:

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

* * *

WHEREUPON, the following proceedings were had at 1:05 p.m.:

EXAMINER STOGNER: Hearing will come to order.

Call next case, Number 10,994.

MR. CARROLL: Application of Enserch Exploration, Inc., for the assignment at a special depth bracket oil allowable, Roosevelt County, New Mexico.

EXAMINER STOGNER: Call for appearances.

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

I represent Enserch Exploration, Inc., and I have two witnesses.

EXAMINER STOGNER: Any other appearances?

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of Phillips Petroleum Company in opposition to the Applicant.

I have two witnesses to be sworn.

EXAMINER STOGNER: Any other appearances?

Will all the witnesses please stand to be sworn at this time?

(Thereupon, the witnesses were sworn.)

EXAMINER STOGNER: Mr. Carr?

MR. CARR: May it please the Examiner, I have a very brief opening statement.

As you are aware, this case involves an Application filed by Enserch Exploration, Inc., by which we are seeking authorization to increase the producing rates from the South Peterson-Fusselman Pool in Roosevelt County, New Mexico.

As you will see, there are only two operators in the pool -- Enserch, Inc., and Phillips Petroleum Company -- and the pool has been operated for almost 20 years on a checkerboard development pattern.

Back in 1978 Enserch came before the Division and sought the adoption of special pool rules for this pool. That application was granted by Order Number R-5771, and 80-acre spacing was by that order established on a permanent basis for the pool. This has resulted in a depth bracket allowable for the pool of 267 barrels of oil per day. This is a standard depth bracket allowable for 80-acre spacing.

Today we will present evidence that will show that the operators have been able to operate wells in this pool for the past 15 years under these rules, but we now have reached the last stages in the development of this reservoir, that the reservoir today is substantially watered out, and we need to increase allowables if in fact we are going to be able to increase our producing rate sufficiently to maximize the recovery of the remaining reserves in this pool, thereby permitting waste. That's what we will show.

I will call two witnesses. I will call a geologist who will provide you with a general geological picture of this reservoir, and then we will present engineering testimony that will review production histories on the wells that still produce from the pool and review other engineering factors which dictate that if we are to effectively produce this reservoir in its twilight years, that in fact allowables must be increased and production rates must now be accelerated, because if we do not, the only result will be waste.

EXAMINER STOGNER: Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Mr. Examiner, we're here in opposition to the request.

As Mr. Carr explained to you, the pool was originally developed by Enserch as a -- based on a farmout arrangement with Phillips. The result of that farmout arrangement was a checkerboard configuration in this pool.

You will see from the displays that many of the spacing units are laydown 80-acre tracts within the section, and with one oil well in each of those 80-acre tracts.

Order R-5771 established the rules and procedures for the pool. Here's a copy of that order.

Phillips and Enserch have operated this pool for some 16, 17 years with a depth bracket oil allowable of 267 barrels.

This is an active, water-drive reservoir. There is a significant structural component.

There is only one well that has any conceivable opportunity of benefiting from increasing the oil allowable above the 267, and that is a well operated by Enserch at the highest structural point of the reservoir.

These technical people have talked to each other. Mr. Carr and I encouraged our clients to discuss this and try to resolve it without requiring your judgment and attention. The parties were unable to do so in this case.

It is our understanding that Enserch bases its hypothesis that increasing the voidage of the reservoir at this time will somehow increase ultimate recovery, and that hypothesis is based upon a SPE paper from 1978.

It will be our testimony that regardless of what that paper hypothecated, in this reservoir it didn't work, it hasn't worked and it won't work.

What's going to happen, our witnesses will tell you, is that by increasing the oil allowable, Enserch with already the best well in the pool, with the best structural advantage, is going to take the remaining oil that we would produce from our wells.

In addition, we will tell you that this is nothing more than rate acceleration, and by increasing the oil rate you're simply giving them our oil and letting them produce it faster.

We're opposed to this. Water encroachment, water drive is still a significant factor in this well -- in this pool. And that increasing the allowable at this point serves no purpose but to benefit one operator with one well at the expense of the other.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Carr, you may call your witnesses first.

MR. CARR: May it please the Examiner, at this time we call George Faigle.

<u>GEORGE FAIGLE</u>,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. George Faigle.

Q. Where do you reside?

A. Midland, Texas.

Q. By whom are you employed and in what capacity?

A. Enserch Exploration, development geologist.

Q. Have you previously testified before this Division?

A. Yes.

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

A. Yes.

Q. In fact, that testimony was offered in a case that involved this very same area; is that right?

A. That's right.

Q. Are you familiar with the Application filed in this case on behalf of Enserch Exploration, Inc.?

A. Yes.

Q. And are you familiar with the South Peterson-Fusselman Pool and the wells located therein?

A. Yes.

MR. CARR: Are Mr. Faigle's qualifications acceptable?

EXAMINER STOGNER: Mr. Faigle is so qualified.

Q. (By Mr. Carr) Could you briefly state what Enserch seeks with this Application?

A. Enserch seeks special pool rules for the South Peterson-Fusselman Pool, special depth bracket allowable of 500 barrels of oil per day and permanent field rules.

Q. What are the current production limitations on wells in this pool?

A. Statewide rules, GOR of 2000 to 1 and depth bracket allowable.

Q. And what are the spacing requirements for the pool?

A. Eighty acres.

Q. So it's a standard depth bracket allowable for 80-acre spacing?

A. Yes.

Q. Have you prepared certain exhibits for presentation here today?

A. Yes.

Q. Could you identify what has been marked Enserch Exhibit Number 1 and identify this for Mr. Stogner?

A. Exhibit Number 1 is a geographic location plat for orientation only, the South Peterson-Fusselman Pool being illustrated by the red dot.

Q. And other than just generally orienting us as to the portion of the State involved, that's all this exhibit is offered for?

A. That's correct.

Q. All right. Let's go to Exhibit Number 2. Identify and review that, please.

A. Exhibit Number 2 is an orientation map. The red outline indicates the remaining productive area. It also shows the pool operators, Enserch and Phillips. All wells within one mile of the Number 1 Lambirth are indicated by a completion date.

Q. And that well is the well that's indicated with the red arrow?

A. Right. The Number 1 Lambirth is the well indicated with the large red arrow.

Q. Now, the area that you have indicated with the circle on this Exhibit, that's not the pool boundaries but just the acreage which you estimate now still productive in the reservoir?

A. That outlines the are of the productive wells, right.

Q. All right. Let's go to Enserch Exhibit Number 3. Will you identify that, please?

A. Exhibit Number 3 is a structure map depicting the configuration on the top of the Fusselman. It also indicates the current Fusselman producers in red and the cross-section trace in green.

Q. Was this exhibit prepared from the well-control information, or did you also integrate any seismic data into this?

A. Well control.

Q. And basically, this just gives you a structure map showing the top of the Fusselman in this area?

A. Correct.

Q. Let's go to the cross-section, Enserch Exhibit Number 4, the trace for which is indicated on 3, and I would ask you to review each of the wells on that exhibit for Mr. Stogner.

A. Exhibit 4. This shows the Enserch well, the second well in from the left, and the three Phillips wells which are the offset producers. It shows the structural position of these wells, it shows the perforated intervals in these wells, the depth at which they were perforated and the thickness of the perforated zone.

It also shows down at the bottom the subsea depths of these perforations. Note that the base of the subsea at the base of the perforations is the same in the Enserch Number 1 and the Enserch -- and in the Phillips Number 2-A.

Q. So in the Enserch well, the well that you're primarily concerned about, and the immediate offsetting Phillips well to the north, the bottom of the perforated interval is identical?

A. Correct. Now, this -- Therefore a rising oil-water contact would affect both wells equally. There would be no advantage to either well.

Also, the cross-section shows the recent water cuts in each well, and it illustrates that the pool has essentially watered out.

Q. Are these the only wells now producing from the reservoir?

A. The wells colored red are the only Fusselman producers.

Q. Now, you have got -- You have indicated on this the base of the Penn or the top of the Fusselman; is that right?

A. Yes.

Q. Is that a fairly easy marker to pick throughout this area?

A. I wouldn't call it easy. It's pickable. You --

Q. Is it fair -- Is it a marker that as a geologist you would not have substantial difficulty in locating?

A. No.

Q. No, you would not?

A. I would not have substantial difficulty in locating it.

Q. Is the Enserch Lambirth Number 1 Well the highest well structurally in this pool?

A. At the top of the Fusselman it is the highest structural position.

Q. And yet it is open in an interval that corresponds to the interval that's open in offsetting wells?

A. Yes, either equal to or lower than the open interval in the offset production.

Q. Mr. Faigle, what general conclusions about this reservoir have you been able to reach?

A. The South Peterson field has four remaining productive wells. The reservoir is dolomite with fracture and intercrystalline porosity.

Although the Number 1 Lambirth occupies the highest structural position in the field, the base of the perforations show that the Number 1 Lambirth has no advantage over the Phillips wells, assuming a rising oil-water contact.

However, this appears to be irrelevant, since the main reservoir has watered out, as illustrated by the water cuts in the range of 94 to 99 percent.

This concluded my part of the project, which was to provide a current geologic picture to be used as a basis for the engineer's reservoir study.

Q. Enserch will also be calling an engineering witness?

A. Yes.

Q. Were Exhibits 1 through 4 prepared by you?

A. Yes.

MR. CARR: At this time, Mr. Stogner, we move the admission into evidence of Enserch Exploration Exhibits 1 through 4.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Exhibits 1 through 4 will be admitted into evidence.

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

EXAMINER STOGNER: Mr. Kellahin, your witness.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Faigle, on Exhibit 3, the Fusselman structure, are you mapping the top of the Fusselman structure on that exhibit?

A. Yes.

Q. The top of the structure, the top of the Fusselman, if you will, for structural mapping purposes, can be found on the log of each of the four remaining producing wells?

A. Yes.

Q. You don't have any trouble picking the top of the Fusselman?

A. No.

Q. When we look at the structure map, when we look at the top of the Fusselman, your Lambirth Number 1, is it a minus 3320? Am I reading that correctly?

A. Yes.

Q. And as we go north to the Phillips 2A Lambirth, that's a minus 3401?

A. Yes.

Q. Difference of about 81 feet?

A. Yes.

Q. Okay. On the cross-section, your Exhibit Number 4, there are penciled in on my copy some water cuts. Do you have that on your copy?

A. Yes.

Q. When we look at the Phillips 2A Lambirth on the bottom, it says 94-percent water cut?

A. Yes.

Q. What's the 1921? That's the total barrels of fluids produced on a daily basis?

A. I don't see any 1921 on my Number 2A Lambirth.

Q. All right, sir. I have "1921 barrel fluid per day", a dash, and then it says "94'. Is yours done the same way as mine?

A. I'm afraid you've got a work copy.

Q. Ah. Okay, good, I have an advantage over you now.

EXAMINER STOGNER: Let's make sure that we have all Exhibit Number 4s.

MR. KELLAHIN: Yes, hang on just a minute.

Q. (By Mr. Kellahin) Is yours like mine?

A. No, sir, this is not the final edition.

MR. KELLAHIN: Okay, Mr. Carr has done me in.

MR. CARR: Mr. Examiner, I apologize to you and Mr. Kellahin for that. I want you to know I did not write those numbers in.

EXAMINER STOGNER: Can we borrow a Xerox machine?

MR. KELLAHIN: All right, hang on.

May I approach the witness again, Mr. Examiner, and make sure he and I are looking at the same thing?

EXAMINER STOGNER: Sure, if Mr. Carr has no problem with that.

MR. CARR: No problem.

MR. KELLAHIN: All right, sir. Check and make sure -- Now I have what you have, right?

All right, he does.

Q. (By Mr. Kellahin) All right, back to my question.

On the 2A Lambirth, it's the one on the far left of the cross-section, the Phillips-operated well shown on Exhibit 4, 94-percent water cut.

To arrive at that water cut, you're simply taking total barrels of fluid produced per day?

A. It's for a month. The water cut is derived from a monthly production figure.

Q. All right, you've got a monthly production figure and you're taking total fluids produced, and you're dividing by the total water produced?

A. Not exactly, I'm dividing into the total water produced.

Q. Okay, and that would give you the 94 percent?

A. That gives me the percent water cut.

Q. So the numerator is the water, and the total fluids is the denominator?

A. Yes.

Q. Okay. And this is for the month of December of 1993?

A. Yes.

Q. Do you have the equivalent water cut for the Enserch 1 Lambirth for December of 1993?

A. No.

Q. Okay. When you look at May of 1994, the water cut in the Lambirth well is 89 percent, right?

A. Yes.

Q. Lambirth Number 1 Enserch Well enjoys about 80 feet of structural advantage to the Phillips well at the top of the structure?

A. On the top of the structure, not the reservoir.

Q. At the top of the structure.

As a geologist, do you see any geologic evidence that does not support the conclusion that this is a water-drive reservoir?

A. Repeat the question.

Q. Yes, sir. Everything that you see geologically supports the conclusion that this is a water-drive reservoir?

A. Yes.

Q. Wouldn't you think that the downstructure Phillips well is going to have a higher water cut than the Enserch well which is farther upstructure?

A. Yes, it does.

Q. And that's what we see, isn't it?

A. Yes.

Q. Now, how do we pick the bottom of the Fusselman on this cross-section?

A. I don't. I assume the Fusselman is continuous down through the top of the granite.

Q. What allows you to make that assumption?

A. Confusion about nomenclature.

Q. Okay. Anything else, other than confusion about nomenclature?

A. Disagreement of the experts.

Q. Okay. The base of the Fusselman is truncated, is it not?

A. No.

Q. The base of the Fusselman hasn't been eroded in some of these wells?

A. No.

Q. How have you determined the base of the Fusselman?

A. Top of the granite.

Q. Okay, and where on this display do I find that represented, looking at Exhibit 4?

A. There is no correlation line indicating the top of the granite, because several of the wells didn't get there, so I couldn't make a continuous line.

On an individual well I can give you that figure if it was penetrated.

Q. Tell me again why you've concluded there's no advantage, even though the Enserch well is some 80 feet higher structurally, at the top of the structure, than the Phillips well.

A. We have the top of the structure, which is not the top of the reservoir. It's tight rock at the top of the Fusselman in the Number 1 Lambirth. We have to go 60 feet down into the Fusselman to encounter the top of the reservoir. We find the top of the reservoir and perforate an interval within the top of that reservoir.

Now, the bottom of that perforated interval is the same subsea as the bottom of the perforated interval in the Phillips 2A Lambirth well and, in fact, lower than the bottom of the perforated interval in the 3A Lambirth and the 1A Lambirth.

My contention is, since the bottom of the perforations are the exact same subsea elevation, any rising oil-water contact is going to encounter the wells at the exact same time, and therefore there's no structural advantage at the base of the perforations.

Q. When we look at the Enserch Lambirth 1, show me what you think on that log is the top of the reservoir that's being produced?

A. 7808.

Q. And that's the top of the red line?

A. Yes.

Q. Which is the equivalent of the perforation?

A. It's the top of the perforation.

Q. All right. Top of the perforation, in your opinion, is the top of the oil reservoir in the Fusselman?

A. As we define it with a porosity cutoff.

Q. And what is your porosity cutoff?

A. I believe it was about ten percent in this well.

Q. All right. If we move over to the Phillips 2A Lambirth, what's the footage on the log that shows me the top of the oil reservoir on that log?

A. Well, I'm having a little trouble reading that. It looks to be about 7832, the top of the red zone, plus or minus a foot.

Q. All right. Am I correct in understanding your conclusion that the Enserch Lambirth 1, the top of that oil reservoir is at about 7808, and when we move over into the Phillips well, the 2A Lambirth, the top of the oil reservoir is at 7832?

A. Okay. No, wait a minute. Well -- Oh, yes, in drilling depth, okay.

Q. I'm sorry?

A. In drilling depth, which does not account for surface elevation. You have to switch to subsea if you want to compare them.

Q. I'm trying to compare them, and I want to get the equivalent footages in each well and have your opinion as to what that depth is for the top of the oil.

A. Okay. If you will look -- For example, the Phillips 2A well, if you'll look after the 7832-38, the parentheses, minus 3418 to -24, this is the subsea depth of the perforated interval.

Q. All right, minus 3407, is that equivalent to the top of the oil?

A. Where did 3407 come from?

Q. Well, it's in the right-hand margin of that log on my copy.

A. I've got a 3401.

Q. All right, that's a "1" and not a "7"?

A. That's the top of the Fusselman, not the top of the reservoir.

Q. All right, give me the top of the oil reservoir.

A. In the Phillips 2A?

Q. Yes, sir.

A. 3418.

Q. All right, 3418.

And when I go over on the Lambirth 1 Enserch Well, give me that footage for the top of the oil reservoir.

A. 3380.

Q. Thirty-three-oh-eight?

A. -- -eight-zero.

Q. 3380, all right. Okay, we've got a difference of 38 feet.

A. On the top of the perforations.

Q. And are you telling me the top of the perforation in each well is the equivalent of the top of the oil column in the oil reservoir?

A. Originally.

Q. Okay, I want to find the top of the oil.

A. The oil is essentially gone. It's been watered out.

Q. Okay. So if I use minus 3380 as being the highest point in your well that would have produced oil and compare it to minus 3418 as you analyze it in the Phillips well, that would be the top or the highest point in that well in which oil could have or would have been produced?

A. Yes.

Q. Okay. You enjoy an advantage under that interpretation of 38 feet?

A. The oil-water contact comes from the bottom upward. It would encounter the bottom perforation before the first. And since they are exactly the same, a rising oil-water contact would meet the bottom perforation in each well at the same time.

Q. Okay.

A. The top is irrelevant, when you're trying to figure when the well is going to water out.

Q. Okay. If it's a bottom-water-drive reservoir, water is coming up. When it hits the lowest perforation in each well, is it watered out?

A. No, it starts to cut water.

Q. Oh, okay. No edge drive, no edge contribution of water in the reservoir?

A. Not in my opinion.

Q. Okay. And so that is the basis by which you say there's no advantage --

A. Yes.

Q. -- between the Phillips well and the Enserch well --

A. Yes.

Q. -- is because the bottom perforations are equivalent?

A. Are equivalent subsea depth.

Q. And as the water rises, they're both exposed to the water at the same point?

A. Yes.

Q. Okay. Give me a porosity cutoff in the Lambirth 1 well. When we look at the bottom perforation in that well, do we have any porosity above 10 percent?

A. Repeat the question.

Q. Yes, sir, I'm trying to see how much net pay above 10 percent you have in your Lambirth Number 1 Well.

A. I don't have that figure here.

Q. Okay.

A. It has to be cross-plotted.

Q. All right. Have you done it for the Phillips 2A Lambirth Well?

A. No.

Q. Did you use any porosity cutoff for that well?

A. Ten percent.

Q. All right. How about the other two wells? We've got two more Phillips wells. You mentioned earlier that there were four producing wells left in the pool. Did I understand that right?

A. I believe there's five.

Q. Okay.

A. There's five producing wells.

Q. On Exhibit Number 2, those wells circled in red are the remaining producing Fusselman wells?

A. Yes.

Q. Okay.

A. The Number 3 Lambirth has recently been recompleted.

Q. Into what formation?

A. As a commingled Penn-Fusselman well.

Q. All right.

A. So it is now a Fusselman producer, commingled with the Penn.

Q. Why was that done?

A. Economics.

Q. Fusselman by itself was no longer economic?

A. No.

Q. No, yes? Or no, no?

A. Yes, the Fusselman was no longer economic by itself.

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER STOGNER: Mr. Carr, any redirect?

MR. CARR: One question.

REDIRECT EXAMINATION

BY MR. CARR:

Q. Mr. Faigle, you indicated you didn't see any evidence of an edge water drive. Would an edge water drive, as opposed to a bottom water drive, in your opinion, make any difference on how the reservoir is performing?

A. Not anymore.

Q. And why not?

A. The wells have essentially watered out, as illustrated by the current water cuts.

MR. CARR: That's all I have.

EXAMINER STOGNER: Thank you, Mr. Carr.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Faigle, was there any initial depth of the oil-water contact in the Fusselman formation whenever the zone or the pool was first discovered?

A. It's referred to in the literature as a minus subsea 3450, approximately. People's opinions vary on this, but this is about an average.

Q. When you say "literature", what more specific are you referring to?

A. I believe -- Well, I can't cite the exact literature, but the West Texas Geological Society publishes field studies, Reservoirs International, Inc., published a field study that was sold to the public, and various speakers at noon luncheons have covered this topic.

Q. Has there been any evidence or -- Let me back up a little bit.

I take it these wells are on -- I know you're a geologist, but I take it that these wells that produce are on pump?

A. Yes.

Q. Is there any evidence of coming, or should I be asking the engineer this question?

A. You should be asking the engineer.

Q. Okay, I'll just refer back on that, then.

I want to make sure that I have the wells on Exhibit Number 3 correct. This shows that there are presently five wells producing?

A. Yes.

Q. One of them, you said, was being downhole commingled, and which one was that one?

A. The Number 3 in the south half of the northeast quarter of 31.

Q. And that was just a recent downhole commingling?

A. I believe it was in May.

Q. In May.

Now, you show a well marked in red down in Section 10 to the south and to the west. Is that a --

A. That well is also included in the South Peterson-Fusselman Pool.

Q. But not within the same structure?

A. No, it's on a separate satellite structure.

Q. Now, would this be a sixth well within the pool, and no others, or are there some other satellite producing wells?

A. That's the extent of the Fusselman producers as listed in the production books.

Q. Is it your opinion that the Fusselman is the basement structure in this particular area, or is there another basement structure before you get to the Precambrian?

A. A basement structure?

Q. The bottom-most.

A. the Fusselman sits on top of the granite basement. I don't know if that answers your question or not.

Q. That's essentially it. You said that there was a problem with nomenclature, and I can't --

A. Yes.

Q. -- visualize a problem -- the base of the

Fusselman as the Precambrian, or the granite in this instance. I don't see --

A. I chose --

Q. -- where there's a problem with the nomenclature.

A. Well --

Q. What do you mean there's a problem with nomenclature? Maybe you need to explain that to me.

A. Okay. I chose to use the nomenclature that the Commission recognizes as this dolomite reservoir is Fusselman. There have been published reports that claim there's a Montoya section in here. There have been other published reports that say there's an Upper Silurian section in here.

The problem you run into is that it's all the same lithology, basically, and there's no physical or lithologic difference between them, and they cannot be picked on log character. It's an alternate interpretation of the same data.

Q. So this particular pool, being Fusselman, includes from the top of the Fusselman down to the base of the granite in this area?

A. To the top of the granite.

EXAMINER STOGNER: To the top of the granite, I'm sorry.

I have no other questions of this witness at this time?

Are there any other, either cross-examination or redirect?

MR. CARR: No, sir.

EXAMINER STOGNER: Mr. Carroll?

MR. CARROLL: (Shakes head)

EXAMINER STOGNER: You may be excused.

Mr. Carr?

MR. CARR: At this time, Mr. Examiner, we would call Ralph Telford.

RALPH B. TELFORD,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Ralph B. Telford.

Q. And where do you reside?

A. Midland, Texas.

Q. Mr. Telford, by whom are you employed, and what is your title with your company at this time?

A. I'm employed by Enserch Exploration in Midland, Texas, as a petroleum engineer I.

Q. Have you previously testified before this Division?

A. No, I have not.

Q. Could you briefly summarize your educational background and then briefly review your work experience for Mr. Stogner?

A. I graduated from Texas A&M University in December of 1990. Immediately after graduation I went to work for Enserch in Dallas. I did two years of reservoir simulation while I was in Dallas.

After that, I moved to Midland where I worked in the west Texas and New Mexico areas.

Q. And does the geographic area of your responsibility include the South Peterson-Fusselman Pool area?

A. Yes, it does.

Q. Are you familiar with the Application filed in this case on behalf of Enserch?

A. Yes, I am.

Q. And are you familiar with the South Peterson-Fusselman Pool and the wells that are located therein?

A. Yes, I am.

MR. CARR: Mr. Stogner, at this time we tender Mr. Telford as an expert witness in petroleum engineering.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Mr. Telford, do you have any relatives in Albuquerque?

THE WITNESS: No, I do not.

EXAMINER STOGNER: In that case, I'll accept your credentials.

(Laughter)

Q. (By Mr. Carr) Initially, Mr. Telford, would you explain why Enserch is seeking these special rules?

A. We would like to increase the ultimate recoveries of the Lambirth Number 1 in the South Peterson-Fusselman field.

Q. And to do that you have to increase the allowable?

A. Yes.

Q. Okay. Let's go to what has been marked as Enserch Exhibit Number 5. Would you first identify the first page of this exhibit for Mr. Stogner?

A. What we have here is a stylized representation that Mr. Faigle has created. The black line on the top is the top of the Fusselman reservoir. The two lines in the very middle is the Lambirth 1 wellbore. The horizontal line across the middle of the structure is the original oil-water contact.

You'll notice blue lines moving up and down the structure. This is a representation of the fracturing within the system. The blue dots are the water within the matrix below the oil-water contact, and the green dots is oil within the matrix above the oil-water contact.

Q. Now, did you work with Mr. Faigle in the preparation of this exhibit?

A. Yes, I did.

Q. Tell us what "H.V.L. Concept" means in the caption.

A. High-volume lift. This is something that was put forward by Amoco in an SPE paper which I'll be addressing shortly.

Q. Is this a diagrammatic representation of how Enserch views the reservoir at this time?

A. This is how we view the reservoir at its discovery. Currently -- Well, I take that back. This is how we view it now.

Q. If we look at this diagrammatic sketch, the well in the center is the Enserch Lambirth Number 1?

A. Yes.

Q. And that's the well that Mr. Faigle indicated was at the highest part of the reservoir?

A. Yes.

Q. Let's go to the second page of this exhibit. Could you identify this for Mr. Stogner?

A. This is part of a reservoir study performed by Reservoirs International, Incorporated. The study was performed in 1990. The data was supplied to them by both Phillips and Enserch.

What we have here is a plot -- a cross-plot of porosity and permeability. If you'll notice, there is a permeability system in the 1-to-.01 millidarcy range, and another system above 10 millidarcies, and less than 1000 millidarcies.

Q. If I look at this page, this is from a study. Did you commission the study to be run on this reservoir?

A. No, we did not They came to us.

Q. And you supplied certain information to them?

A. Yes, we did.

Q. Did you supply core data?

A. Yes, we did.

Q. And other information?

A. And other information, yes.

Q. Were you also asked to pay for part of the study?

A. No, we were not.

Q. Has it subsequently been made public and --

A. Yes.

Q. -- for sale throughout the --

A. Yes, it has, and we've purchased a copy.

Q. Basically, this is simply a cross-plot of core permeability and --

A. And porosity.

Q. -- and porosity?

A. And what it shows is a dual-permeability system.

Q. If I look at the caption at the bottom, it talks about the "Lower permeability samples are matrix dolomite; higher values represent karst rubble." What is karst rubble?

A. It tells me that we have a fracture system.

Q. Let's go to the next page in this exhibit. Would you identify that, please?

A. This is another page from the study. It just shows the dual porosity system again.

And if you'll notice the last sentence on the caption, it says "Permeability variation of .94, indicating a very heterogeneous distribution", i.e., fractures and a matrix system. "This resulted in a premature water breakthrough in the reservoir."

Q. Okay.

A. And this goes back to our representation on Exhibit Number 5, showing the fracture system being watered out.

Q. Okay, let's go to the last page of this exhibit. Would you identify this, please?

A. This is a histogram showing the frequency of permeability in core samples, arranged in classes defined by the logarithm of the permeability.

Basically what we have is a bimodal distribution where you have your low-permeability system, which is your matrix, and your high-permeability system being your fractures. Just more indication of fracturing.

Q. What basically does Exhibit 5 and the attachments show you?

A. That we have a dual-permeability system and that the fracture system is watered out.

Q. What about the matrix?

A. It is low permeability.

Q. Do you have an opinion as to where the remaining oil that's being produced in this reservoir is located?

A. Yes, I do. It's the matrix.

Q. Let's go from this to your Exhibit Number 6.

First, identify what this is and review the code. And then I'd like you to explain the information on this exhibit for the Examiner.

A. Okay, what we have is a production plot of the Enserch Lambirth Number 1, the South Peterson-Fusselman Pool. The green curve is oil production, the red curve is gas production, the yellow curve is the GOR.

I'd like to note that the GOR is flat, which is indicative of a water-drive reservoir.

Next we have a dark-blue curve, which is water production, and the light-blue curve is the water cut.

Q. All right. Let's go to the oil production from this reservoir. What does this tell you about the Lambirth Number 1?

A. If you'll notice, from the inception of the well until about 1986, the production was relatively flat. This well was curtailed at the fieldwide allowable of 267 barrels a day. Also, the well was continuously pinched back due to water production.

Q. And does that pinchback account for the decline that we see from 19-, say, -85, forward?

A. Yes, it does.

Q. What was the initial potential for this well?

A. Over 550 barrels a day.

Q. So in fact what we do have is a curtailment in the earlier --

A. Yes.

Q. -- portion of the well life?

A. Yes.

Q. All right. What happened to the oil production in mid-to late 1993?

A. The well started to load up and die. We were making 30 barrels a day. Water started becoming a problem, so we put the well on beam pump.

Q. At that time, about what oil producing rate were you experiencing from the well?

A. Once we put it on beam pump, it was about 60 barrels a day.

Q. Prior to that time it had been -- ?

A. Thirty.

Q. Okay. What happened when you put the beam pump on the well?

A. The oil production increased, but also so did the water production. We were experiencing anywhere from an 88- to an 80-percent water cut.

Q. And then what happened after that?

A. After that we put the well on submersible pump.

Q. And when did that occur?

A. That occurred the 1st of May.

Q. 1st of May of this year?

A. Of this year.

Q. All right. If we look at Exhibit Number 6, the curves that show water cut and water production only appear in the, oh, 1993 period on.

You indicated there was water production -- or water-production problems were experienced prior to that time?

A. Yes.

Q. Why is that not shown on this exhibit?

A. Okay, on the water cut, you'll notice that the scale is from 70 percent to 100 percent. And when the well would start to make water we would pinch it back, so you'd only have a few days production of water, and it's not going to show up on the plot. The minimum was 100 barrels a day --

Q. Now --

A. -- or a month.

Q. -- before you put the submersible pump on the well in May of this year, what producing rates were you experiencing from the well?

A. Sixty barrels a day before we put it on submersible pump.

Q. Okay. Now, let's go to the next exhibit, Exhibit Number 7. Identify and review this for Mr. Stogner.

A. This is the test data, daily test data for the Lambirth Number 1 after we put it on submersible pump.

Q. Now, you've been 30 barrels before this?

A. We've been 30 barrels, then 60 barrels, and then we went to over 300 barrels a day initially. And it dropped off to 250, 280.

Q. Okay. Generally review this for the Examiner.

A. Okay, the green curve, again, is oil production, the dark blue curve is water production, and the light blue curve is water cut.

You'll notice we produced the well at an average rate of 250 to 275 barrels of oil a day. There is some spiky data to the plot, and that's due to electrical problems and also due to lightning.

Later on, in June, you'll notice that the oil production increased. We installed a larger submersible pump in the well, and the oil production went up.

And the curious note is that the water cut actually went down a little bit. We were slightly over 90 percent, and now we're at about 88 percent.

So oil production has increased and water cut has decreased.

Q. What does this information on the Lambirth Number 1 tell you about what is required to effectively produce this reservoir?

A. You've got to increase your drawdown pressures. By increasing your drawdown pressures, you can recover more oil from the matrix.

Q. And so by creating a pressure differential in the formation, more of the hydrocarbons come out of the matrix portion of the reservoir?

A. That is correct.

Q. Let's go now to what has been marked as Enserch Exhibit Number 8. Would you identify this, please?

A. This is a production plot of the Phillips Lambirth 1A in the South Peterson-Fusselman Pool. Again, oil is green, gas is red, water production is dark blue, and water cut is light blue.

Q. Okay. What does this show you about the Lambirth 1A?

A. The Lambirth 1A originally IP'd for over 600 barrels a day, and production declined, the well eventually died, and then we placed it on beam pump. Immediately, the water --

Q. When did that occur, approximately?

A. In 1980 to 1981, it looks like.

Q. Okay. Then what happened?

A. Then, as I say, the water production increased, the fractures watered out. This continued until, it looks like, 1990.

You'll notice that the producing water cut was in excess of 95 percent. They placed the well on submersible pump, and water cut immediately dropped to below 90 percent.

Water cut was essentially flat for several months and steadily increased until the well eventually was watered out, and it is currently uneconomic.

Q. First part of the life, the production was coming from the fracture system; is that right?

A. That is correct.

Q. When that declined, they went to the beam pump?

A. Beam pump.

Q. Later -- When that was no longer sufficient, a submersible pump was put on the well?

A. And that increased the recoveries.

Q. And then what has happened since then?

A. They've watered the well out entirely. The fracture system and the matrix is watered out.

Q. Okay. Let's go to Enserch Exhibit Number 9. Identify and review that for the Examiner.

A. That is production plot of the Lambirth 2A in the South Peterson-Fusselman Pool.

Q. This is the immediate north offset to the Lambirth Number 1 --

A. Yes, it is.

Q. -- your primary well?

A. Yes, it is.

Q. What does this exhibit show?

A. Basically the same thing we've seen on the Phillips Lambirth 1A. The well produced flowing for several years until it finally died.

They placed it on beam pump; water cut gradually increased until they got to in excess of 95 percent again.

They placed the well on submersible pump; water cut dropped to below 90 percent, stayed flat and started to increase again.

Basically what we're seeing is that the --

originally they were producing water -- They were producing oil from the fracture system; the fracture system watered out.

They placed the well on submersible pump, and then they started producing from the matrix.

Q. Generally, what conclusions can you reach from this production information from these three wells in the South Peterson-Fusselman Pool?

A. To increase recoveries and prevent waste, you must increase the drawdown. If you don't, you will leave oil behind in the matrix.

Q. Have you seen any water breakthrough or anything as a result of this activity?

A. No, I do not.

Q. And why not?

A. Because the fractures were already watered out.

Q. Let's go to Enserch Exhibit Number 10. Would you identify this for the Examiner?

A. This is an SPE paper written by Amoco in 1978.

Q. And how does this paper relate to this particular Application?

A. This paper is what started me looking at the South Peterson field and seeing if there was an application here.

Q. Basically what does this paper show you?

A. This paper shows -- I'll just jump straight to the conclusions, is, number one, "High volume -- "

Q. They are on what? The fourth page --

A. The fourth page --

Q. -- of the exhibit?

A. -- yes.

"High volume lift installations in some West Texas natural waterdrive reservoirs are successful in increasing rate and ultimate recovery over that expected with conventional lift methods", i.e. beam pumps.

Number 3, "Maximum benefit from high-volume lift is achieved when installed on wells with producing water cuts in excess of 70 percent...and less than 95 percent."

And 4, "Concern over premature water breakthrough and reduced ultimate recovery from application of high-volume lift is unsubstantiated in most heterogeneous" -- i.e., fractured -- "West Texas carbonate, oil-wet, natural waterdrive reservoirs."

Q. How does your experience and the information, production information, you've gathered on the wells in this pool compare to the conclusions stated in this paper?

A. I see that there's a direct correlation.

Q. In fact, does your experience confirm these conclusions?

A. Yes, they do.

Q. In your opinion, would approval of this Application and the increased allowable and resulting increased production rates from the Lambirth Number 1 result in the recovery of hydrocarbons that otherwise are not going to be produced?
A. That is correct.
Q. In your opinion, will correlative rights be impaired by the approval of this Application?
A. No, they will not.
Q. And why not?
A. Because the fracture system is already watered out. That's the only thing that you could possibly affect.
Q. Could you identify for the Examiner what has been marked as Enserch Exhibit Number 11?
A. This is a letter from the Energy, Minerals and Natural Resources Department of the State of New Mexico, signed by Jerry Sexton, authorizing Enserch to increase their allowable temporarily until we have a hearing.
Q. And that's what resulted in the Application for hearing being filed in this case?
A. That is correct.
Q. And at what rate are you now producing the Lambirth Number 1K?
A. Approximately 331 barrels of oil a day.
Q. Following the entry of any order in this case,

you will coordinate the production from the Lambirth Number 1 to assure that the well is not in an overproduced status, in accordance with existing OCD rules; is that correct?

A. That is correct.

Q. Is Exhibit Number 12 a copy of an affidavit simply confirming that notice of this Application has been provided to Phillips?

A. Yes, that is correct.

Q. Were Exhibits 1 through 12 either prepared -- I'm sorry, 5 through 12 either prepared by you or compiled under your direction?

A. Yes, they were.

Q. Can you testify as to the accuracy of the exhibits?

A. Yes, I can.

MR. CARR: At this time, Mr. Stogner, we would move the admission into evidence of Enserch Exhibits 5 through 12.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Exhibits 5 through 12 will be admitted into evidence at this time.

MR. CARR: And I pass the witness.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin, your witness.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Have you attempted to quantify, Mr. Telford, the original oil in place?

A. No, I have not.

Q. Have you attempted to quantify what portion of oil production is attributable to being stored in the fracture system, as opposed to matrix?

A. No, I have not.

Q. At what point did we stop producing oil out of the matrix and start getting contribution -- at what point did we stop producing oil out of the fracture system and start getting matrix contribution?

A. You want to know when you're not making anything out of the fractures and -- I can't give you that number.

Q. Okay.

A. I don't think there's anyone that can.

Q. Let's look at that last display where you plotted production for me on one of the Phillips wells.

A. Which one?

Q. Bear with me for a second. I'll find it here. It's Exhibit 9.

A. Exhibit 9, which would be --

Q. Lambirth 2A.

A. -- Lambirth 2A. Okay.

Q. Yes, sir. The hypothesis in the SPE paper is that there are some reservoirs -- there was a Devonian -- the case studies represented Ellenberger, Devonian --

A. -- and others.

Q. -- and Strawn and others, I think they threw them all in there. No specific study of a Fusselman reservoir, was there?

A. That is correct.

Q. It said in the Ellenberger and the Devonian that in some reservoirs this might work?

A. That is correct.

Q. All right. And the hypothesis was that at a certain point in time you could put in high-volume submersible lifting equipment and extract larger volumes of fluids from the reservoir and thereby maybe increase recovery?

A. That is correct.

Q. All right. When we look at the Lambirth 2A --

A. Yes.

Q. -- it says "installed submersible". Follow the arrow.

A. Yes, I see it.

Q. That leads me down to, oh, January or February of 1991?

A. Okay.

Q. All right? Am I reading this correctly?
A. You're reading this correctly.
Q. All right. They put the submersible in the well. Do you know what the capacity of that submersible pump was to lift total fluids?
A. No, I do not. That information has not been supplied to me.
Q. Okay, but some kind of submersible pump went into the wellbore?
A. Yes.
Q. What happens then to these production plots?
A. What do you mean, what happens then?
Q. Well, where do they go? What happens to the oil rate versus the water rate?
A. Well, if you go to the oil rate, the oil rate is increased.
Q. And the oil rate is the green line?
A. That is correct. The water rate also increases, but the water cut goes down.
Q. And the water cut is the light --
A. -- light blue, which means you're making proportionately more oil than you are water --
Q. I'm with --
A. -- incrementally.
Q. Okay. So this thing takes a steep dive on the --

A. -- on the water cut.

Q. -- water cut, and it gets a kick in the oil recovery curve, goes up?

A. Yes, it does.

Q. All right. Now, move over to January -- January, February of 1992. Do you see the point where the green line starts on a decline again?

A. Uh-huh.

Q. Okay. And at the same point the water cut, instead of going down, goes up?

A. Okay.

Q. What's happened?

A. I could not tell you.

Q. Okay.

A. But I do know that overall the producing water cut is lower than it was before you ran a submersible.

Q. Do you think this example proves your hypothesis, that if you put a submersible pump in the well, that we're going to increase ultimate oil recovery?

A. I think if you use the Lambirth 2A, the Lambirth 1A, and what we've seen so far in the Lambirth 1, I do believe it does do that.

Q. All right, let's look at the Lambirth 2A for a moment.

A. Okay.

Q. That's the one we're looking at right now.

But for the difference between January of 1991 and January of 1992, where you have a climbing oil rate and a dropping water rate, look beyond that, then, and you re-establish an oil decline and an increasing water cut. Right?

A. Yes, I'll agree with that. But you've still recovered more oil.

Q. What tells you you've recovered more oil, as opposed to simply accelerated the rate of recovery of the existing oil?

A. Well, let's go back before we ran the submersible and let's shoot a decline off of that.

Q. Okay.

A. Are you saying that if you extrapolated that out, that you would have the same amount of oil as if you shot a decline off of current production right now? That tells me you've recovered more oil.

Q. Am I correct in understanding the key component of this information is the difference between the January, 1991, and the January, 1992, interval, where we see the steep decline in water cut and the increasing oil recovery, based upon the installation of the submersible pump?

A. Could you restate your question? I'm not sure what you're saying.

Q. All right, sir. The arrow shows the installation of the submersible pump?
A. Yes, and the water cut goes down.
Q. And the oil rate goes up?
A. That is correct.
Q. All right, and you say that's directly attributable to the installation of the submersible pump?
A. Yes, I am.
Q. We are lifting more total fluids, faster, out of this wellbore, and that's helping total ultimate recovery?
A. Yes, you are. You're increasing your drawdown and you're pulling more oil out of the matrix.
Q. Okay, and we can see that difference between January of 1991 and January of 1992?
A. Yes.
Q. And you say that helps make your case?
A. Yes, I do.
Q. Okay. What if I tell you that you've got the wrong date for the submersible pump? That in fact in this well it was not installed until February of 1992?
A. Till February of 1992? Okay, that's fine. Look at your oil. Your oil has gone up again.
Q. We look in February of 1992, my oil rate is going down, and the water rates are climbing.
A. February of 1992. Is February a full month of

production? It takes time to install this equipment. It doesn't happen overnight.

Look at the following month. Your oil rate is even higher than it was before.

Q. Mr. Telford, I asked you, sir, if it was of significance to you that between January of 1991 and January of 1992 the oil rate climbed and the water rate dropped and that that effect was attributable to the submersible pump, and you told me yes.

And I now tell you you've got the wrong date. Doesn't support your conclusion if your date's wrong, does it? Sir? That was a question.

A. Well, it looks to me like that the -- it could be a -- possibly increase the pumping speed, or maybe a larger pumping unit, increase the drawdown.

Q. You're the expert, sir. I don't know.

A. I'm not the expert on the operations of the Phillips Lambirth 2A.

Q. Okay.

A. But it does look like that they increased their drawdown, which would increase the oil production from the matrix.

Q. All right, sir. Let's look at Exhibit Number 8. Now, this is the Phillips Lambirth 1A.

A. 1A.

Q. Lead me through the display here at the point where the submersible is installed. I need to get a straightedge here. I'm guessing somewhere midway through 1989 --

A. -- August.

Q. August of 1989? Something like that?

A. Is it 1989 or is it -- It looks like -- more like it's 1990 to me.

Q. Okay. Installation of submersible pump is -- ? Tell me your best --

A. Best pick off the plot --

Q. Yeah.

A. -- is about August or September.

Q. Okay, of 1990?

A. Roughly.

Q. 1990?

A. Of 1990.

Q. All right. What we see at that point is, the water cut takes a nose dive.

A. The water cut takes a nose dive.

Q. And the oil production takes a steep increase in the plot?

A. Yes, it does.

Q. All right. And shortly thereafter -- and there's some erratic nature to the plots, and I guess that's attributable to how long these submersible pumps are running for X number of days.

A. I can't tell you.

Q. Yeah. But something's happening in the field to make that production erratic; that's not attributable to the wellbore?

A. That's -- And if you'll notice, our production is the same way. We've had problems with electricity and other problems.

Q. All right. Help me as an -- You're the engineer. Tell me where we re-establish a comfortable oil decline curve, if you will, after the installation of the submersible pump when we get that initial kick in oil recovery, and then it starts going down again, doesn't it?

A. Yes, it does. It looks like about halfway through 1991.

Q. It appears as that decline is steeper post-installation of the submersible pump than it was pre-pump?

A. I wouldn't necessarily say that.

Q. All right. Now, let's go to your -- what? The number -- Exhibit Number 7 is the --

A. -- the Lambirth 1.

Q. -- Enserch Lambirth 1.

Let me get this exactly right, now. The sequence of --

A. Are you looking at the daily plot or the monthly plot?

Q. I'm looking at the daily plot tests --

A. Okay.

Q. -- this plot test. And perhaps we should start back one exhibit and go to 6.

A. Okay, that would be fine.

Q. All right, sir. Give me the data now. Prior to 1980-81, how was the well being produced?

A. Flowing.

Q. Okay.

A. The well flowed until September or October of 1993.

Q. All right. Now, I'm going to divide this in steps. From 1980-81, somewhere in that period, then, you put a beam pump on the well?

A. When did you say was the date again?

Q. Well, I thought you said somewhere between 1980 and 1981.

A. No, that is incorrect. It flowed from 1978 till 1993.

Q. All right. In 1993, then, you put what on the well?

A. We put a beam pump.

Q. Okay. The capacity of that beam pump to lift total fluids was what, sir?

A. Approximately 450 barrels of fluid a day.

Q. And you were getting at the end of that period what? About 30 barrels of oil out of that number?

A. Sixty.

Q. Sixty, all right.

A. We went from 30 barrels flowing -- Well, actually, the well was dying, and it went to 60 barrels a day with the beam pump.

Q. When you were getting -- flowing 30 barrels of oil a day, were you also recovering water?

A. No, we were not. Well, small traces, and we'd try to pinch it back to keep it from making water.

Q. Okay.

A. And then eventually the well died.

Q. Okay. And you put the beam pump on, then, in 1993?

A. That is correct.

Q. And that stayed on until you put the first submersible pump on?

A. Yes.

Q. At what point?

A. In May of 1994, which would be the next plot.

Q. All right, May of 1994.

So prior to May of 1994, we didn't have a submersible pump in your well?

A. That is correct.

Q. Okay. Now we go to Exhibit 7. In May we have the first of the submersible pumps. What was the capacity of that configuration with the initial submersible pump to lift total fluids?

A. It could move about three -- not quite 3000 barrels a fluid a day.

Q. Okay. With what resulting oil rate?

A. We were making approximately 270 to 280 a day.

Q. All right. So that puts you up there just over the allowable?

A. Yes, it does.

Q. All right. At what point did you try any other configuration in the well by -- I thought you said increasing the size of the submersible pump?

A. Yes, we had some problems with the submersible. We had to pull it out, and we re-ran a larger submersible.

And I'd like to state, the submersible we have in the well right now, we have not purchased. It is a test unit.

Q. I don't care --

A. Well, it could get valid. This could be a point later on. But this is a test unit in the well. We ran a larger unit that is capable of 3500 barrels.

Q. All right. So that's the incremental difference. We went from a pump that would do 3000 --
A. Not quite 3000.
Q. Just shy of 3000 --
A. Just shy of --
Q. -- to 3500?
A. Uh-huh.
Q. All right. Now where do we find that on Exhibit Number 7?
A. If you'll look at about the 10th -- it looks like the 10th of June -- you'll notice how the oil has increased.
Q. All right, we've got a break in the data?
A. Yes, a break in the data.
Q. And so about --
A. If you'll -- The break in the data is when we were changing everything out.
Q. All right. So on the 10th of June, now, we've got the 3500-capacity pump in the well, and we're starting to do it. All right.
A. It's -- Yes.
Q. What is the ratio, if you will, or what is the oil production now when you use the 3500 submersible pump that will do that capacity of fluids?
A. The ratio --

Q. Just --
A. The actual oil ratio has gone up.
Q. All right.
A. The rate is now 350 to 360. It varies.
Q. Okay.
A. And you'll also notice that the water cut before we changed the pumps out was approximately 90 percent. Now it's 88 percent.
Q. All right. So water cut goes from 90 to 88?
A. It's decreased. We've increased our pressure drawdown --
Q. Yes, sir.
A. -- and we're recovering more oil.
Q. All right. And then we've terminated the test?
A. The test is still going. This is just the most current data I had.
Q. The data plot, it stops just short of the 25th?
A. Yes, earlier this week.
Q. Okay. We don't yet have any tests on any of these wells to show that we have the ability to produce 500 barrels of oil a day?
A. Could you restate your question?
Q. Well, I'll try to repeat it.
A. Okay.
Q. Your allowable request is for 500 barrels of oil

a day allowable?

A. That is correct.

Q. Your best test will push 360?

A. That is correct.

Q. What are we going to do with the difference?

A. The difference is, our water facilities can only handle 3000 barrels of water a day.

Q. Uh-huh.

A. We are having a larger free-water knockout. It's been on order for a month and a half.

And we've also had lots of problems with the Roosevelt County Electric. They can't supply the voltage that we need when we try running the pump at a higher speed. We pull the voltage down, and it knocks the whole system out.

Q. Okay.

A. And the only way to see if we can do 500 barrels a day would be get a generator out there and another free-water knockout. We should have another free-water knockout within two weeks.

And the Roosevelt County Electric is supposed to have regulators on the line, which will supposedly smooth the voltage, within the next week or two.

Q. All right. So our best test is 360, and that's all we can do right for now?

A. Well, according to IPR analysis it can do a lot higher than that.

Q. When I look at your plot, Exhibit 7 --

A. Yes.

Q. -- you responded to Mr. Carr that this caused you to conclude you were increasing ultimate recovery?

A. On plot number 7?

Q. I thought you did.

A. Yes.

Q. This is it?

A. Yes. I'm showing that I've -- By increasing my drawdown, I'm increasing my rate. I mean, I've decreased my water cut.

Q. And how do we know that's nothing more than rate acceleration for a short period of time, as opposed to increasing ultimate oil recovery?

A. Because we're outrunning the fracture system, we're carrying water out of the matrix that we wouldn't otherwise be able to get.

Q. Do you have enough data to plot a decline, to show your increasing ultimate recovery?

A. It looks pretty flat to me so far. According to the SPE paper, it said the production would be flat for several months and then tail off.

Q. Okay. Have you tried to quantify the additional oil recovery?

A. Not yet.

Q. Tell me something about the Lambirth Number 1 Well. What is its total cumulative oil production to date?

A. To date is approximately 960,000 barrels of oil.

Q. Okay. It's the best producing oil well in the pool, wasn't it?

A. Yes, it is.

Q. Okay. Have you tried to determine what area has contributed oil reserves for a well to produce almost a million barrels of oil?

A. I have tried, but I have not come up with a good answer that I like yet, due to the heterogeneity of the reservoir.

Q. Okay. Have you attempted to construct or make -- either you or someone else in Enserch -- some kind of reservoir-limits test, some kind of test of the well to see how far out it's reaching into the reservoir?

A. No, we have not.

Q. All right. Do you think this well is affecting the Phillips well?

A. No, I do not.

Q. What causes you to believe that that well is not affecting the Phillips well?

A. If you'll look back at Exhibit Number -- Hold on a second. It will be the production plot of the Enserch Lambirth 1.

Q. Enserch Lambirth 1?

A. I'm not sure what exhibit that -- That's Exhibit Number 6, it looks like.

Q. Yes, sir.

A. When Phillips installed their submersibles, did you see any -- Is there any bobble in the oil production rate? And they were moving large volumes of fluid.

Q. So that's your contention --

A. That is my contention.

Q. -- that these wells aren't in communication with each other?

A. I did not say that.

Q. Okay.

A. I said that the Lambirth 1 will not affect the two Phillips wells.

Q. Okay.

A. And I'd also like to point out, if I thought it would, I wouldn't be trying to purchase the two Phillips wells right now.

Q. Well, we think you're going to water us out. I'm happy to sell them to you.

A. Well, we'd be glad to buy them.

Q. Okay.

A. As I say, if we thought we would hurt them, we wouldn't want to buy them.

Q. All right. Any pressure data, pressure information from the reservoir?

A. Yes.

Q. What kind of pressure data do you have?

A. bottoms.

Q. And what does it show you?

A. It shows a static reservoir pressure of 2520 p.s.i. at the top of the reservoir.

Q. Okay. What's happening to the reservoir pressure over the life of the pool?

A. The reservoir pressure has decreased slightly.

Q. Indicative of a good, active water drive?

A. That is correct.

Q. We're getting pressure support from the water influx?

A. We're also seeing that in your GOR.

Q. Okay. What kind of recovery factors do you think we have in this pool?

A. Out of the fractures or out of the matrix?

Q. Beats me. Out of either.

A. Out of the fractures I would say it's fairly high. Out of the matrix probably, unless we can increase our drawdowns, fairly low.

Q. In terms of a percentage do you have a ratio or a percentage?

A. No, I do not.

Q. Okay. If you haven't calculated the original oil in place, how can you tell me a recovery factor?

A. I did not tell you a recovery factor.

Q. How can you tell me what portion is contributed out of the fracture system?

A. I haven't told you what's out of the fracture system either, but I would assume with a high-permeability system you ought to have very high recoveries.

Q. All right. What, in your opinion, is the percentage recovery factor attributed to the fracture system?

A. I would say 70 to 75 percent.

Q. And the matrix?

A. Well, obviously it would be 30 to 25 percent.

Q. Do you see any other well in the pool besides the Lambirth Enserch Number 1 that would have the opportunity to do what you're proposing to do for this well?

A. The Lambirth 2A.

Q. Any other?

A. Possibly the Lambirth 8.

Q. The Lambirth 8?

A. It is temporarily abandoned.

Q. Oh, that's the one up in Section 30?

A. Yes.

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER STOGNER: Thank you, sir.

Mr. Carr, any redirect?

MR. CARR: Very briefly.

REDIRECT EXAMINATION

BY MR. CARR:

Q. Mr. Telford, if you don't go to this high-volume lift method of producing these wells, what's going to happen to them?

A. You're going to leave oil behind, waste oil.

Q. Are you going to continue to produce the wells?

A. Pardon?

Q. Will the wells continue to be produced?

A. Yes, they will.

Q. For how long?

A. I haven't calculated that.

Q. When you get to the end of that there will be, in your opinion, reserves left in the ground?

A. Yes, I do.

Q. You're asking for a 500-barrel-per-day special allowable?

A. Uh-huh.

Q. Is that based on the maximum withdrawal possible under your submersible pump? Is that what you're telling us?

A. The reason we went for the 500 barrels a day is the size of the casing. It's 5-1/2-inch. The most fluid that we can move up a 5-1/2-inch casing with a submersible pump is 5000 barrels a day. Assuming a 10-percent oil cut, that would be 500 barrels of oil a day.

MR. CARR: Okay, that's all I have. Thank you, sir.

EXAMINATION

BY EXAMINER STOGNER:

Q. So far, I've got three of these wells out here, three of the six, on submersible; is that correct?

A. That is correct.

Q. And the other three are on beam?

A. Yes, they are.

Q. Two of those are Phillips submersibles and one Enserch submersible, right?

A. That is correct.

Q. Does Enserch plan to install -- Well, they probably would if this order is approved, I would assume.

Or let me ask it in this way: Are the other Enserch wells good candidates for submersible pumping?

A. The Lambirth 3 is not. It's almost pumped off. The Lambirth 8 is a good candidate.

Q. Okay. Now, why isn't the Lambirth 3 a good one?

A. It's -- We have a fluid level that is about, I'd say, 1500 foot over the pump. We're very close to pumping it off.

Q. Can I use Exhibit Number 5 as an illustration of what you're trying to tell me on that one?

A. Exhibit Number 5. Is that the --

Q. That's the schematic drawing.

A. The schematic drawing. On the Lambirth 3?

Q. Yes.

A. Sure. We're making about 30 barrels of oil a day and approximately 260 water, and it's my belief that the reservoir rock at the 3 is not as good as it is at the Enserch Lambirth 1 or the Phillips Lambirth 2A or 1A.

Q. So for all intents and purposes, that well is watered out and would not benefit by the added allowable?

A. On the Lambirth 3?

Q. Right.

A. I don't think we could get over 267 a day on it. The IPR analysis says we couldn't make that.

And also, since it is a commingled well, I believe our maximum allowable oil rate is 100 barrels of oil a day.

Q. How about the one in Section 10?

A. Which would be -- I don't have a map in front of me. Can I borrow one real quick? Section 10. That's -- You're talking about far to the southwest?

Q. Yes, sir.

A. That is not an Enserch well.

Q. But it is a South Peterson-Fusselman well, is it not?

A. Yes, it is.

Q. Well, what's the higher allowable going to do to it? I don't care if it's not your well or not.

A. I really couldn't tell you, because I'm not familiar with this well.

Q. Do you know --

A. If they have the high fluid level like our Lambirth well does, they could recover more oil as well.

Q. But you didn't include this well in the study?

A. No, I did not.

Q. Any particular reason why?

A. The only data I have on it is production data. And I --

Q. Did you try to find other data in the well files or --

A. I didn't see -- didn't have any other data in the well files. I went through all of our stuff and through this data that George provided me.

Q. I'm sorry, who's George?

A. George Faigle.

Q. Oh. If one is going to do some kind of increase such as that, do you feel it would be necessary to try to get all information on all wells?

A. Yes, I do.

Q. But Enserch failed to obtain information on this one.

Now, I was told -- I understood in the beginning that Enserch and Phillips was the only two operators in this pool. Now you're telling me there's a third?

A. It's not within a mile of the subject well.

Q. I'm -- Hold it, I thought this was poolwide. You want it just for the well? Maybe I've got this wrong.

The Applicant says, Application of Enserch for a special depth bracket oil allowable of 500 barrels a day for the South Peterson-Fusselman Pool.

Is that not what Enserch wants?

A. That is correct, what Enserch wants.

Q. All right. Is this well in the pool or not? And who operates it?

A. Bledsoe operates it.

Q. Bledsoe, okay. But no information was obtained, or you didn't feel necessary to obtain it?

A. I was unable to obtain the information other than production data.

Q. Did you go to the Hobbs District Office and look in the well file?

A. No, sir, I did not.

EXAMINER STOGNER: Mr. Carr, where's the notification exhibit? Is that Number 12?

MR. CARR: It's the last exhibit, Mr. Stogner, notification of --

EXAMINER STOGNER: Do we have a problem there?

MR. CARR: Yes, sir.

EXAMINER STOGNER: So it will be necessary to re-advertise, or re-notify?

MR. CARR: Is that 10 of 6-33?

EXAMINER STOGNER: I'm sorry, what?

MR. CARR: Is that -- Township 10 South, 33 East; is that right?

MR. KELLAHIN: That's correct.

MR. CARR: Yes, and that's in the pool?

MR. KELLAHIN: That's by definition, Mr. Stogner.

EXAMINER STOGNER: Yeah, that's 6 South, 33 East, yes.

MR. CARR: That is within the defined boundaries.

Q. (By Examiner Stogner) Let me ask this question: In your Application you said certain wells in the Fusselman formation in this pool can produce at rates as high as 500 barrels a day.

What wells are capable of -- or were you referring to?

A. The Enserch Lambirth 1.

Q. And which others?

A. That would be it.

Q. It implies plural, you're right. Certain wells, and that's the only one that can.

A. But I do believe the Lambirth 2A could produce probably over the allowable.

Q. The present allowable?

A. The present allowable of 267.

Q. Okay.

A. If pumped off.

Q. Okay, okay.

A. That's why I'm saying other wells could benefit by this increase, not just the Lambirth 1. They couldn't do the 500 a day, but they could probably make 267 a day.

Q. Let me ask a roundabout question here. As far as the 2A goes, what do you think its maximum capability is, given the electrical problems and the submersible pump and all?

A. It's hard to say, because I don't have a fluid level. If I knew what its producing fluid level was -- I know it's not pumped off.

Q. But you feel it would be capable of producing more than the present allowable?

A. Yes.

Q. By 10, 50, 60, 75 percent?

A. Probably 15 to 20 percent at least. The problem is, I don't have the fluid level.

Q. Okay. If the allowable in the pool was increased by 15, 20, 25 percent, say, what would that do to the Number 1?

Would that benefit it, would it hurt it?

A. It would benefit it, but it wouldn't benefit it to the extent that, say, the 500 barrels of oil a day would.

Q. Okay, would it hurt it?

A. I think you could possibly go behind, still, because we still could not maximize our drawdowns.

EXAMINER STOGNER: I have no other questions for this witness.

Any other questions?

May be excused.

Let's take about a five-, ten-minute break.

(Thereupon, a recess was taken at 2:39 p.m.)

(The following proceedings had at 2:50 p.m.)

EXAMINER STOGNER: Hearing will come to order.

Let's see, I believe Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

SCOTT C. BALKE,

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. Balke, would you please state your name and occupation, sir?

A. Scott C. Balke. I'm a petroleum geologist for Phillips petroleum.

Q. Mr. Balke, on prior occasions you've qualified as an expert petroleum geologist before this Division and testified in that capacity?

A. Yes, I have.

Q. Have you as a geologist for your company made an investigation of the South Peterson-Fusselman Pool?

A. Yes, we have.

Q. How long have you been involved in looking at the Fusselman reservoir?

A. For about five years.

Q. So having the Enserch Application filed and being given the responsibility to examine the geology was not a new task for you?

A. That's correct.

Q. As part of your preparation for this case, did you go back and review the geologic evidence that was contained in the Division records with regards to the initial pool hearing in 1978, the subsequent hearing in 1979, and then the two waterflood cases that Enserch and Phillips had against each other later on?

A. Yes, I did.

Q. In addition, have you prepared further exhibits that provide additional information that wasn't known at that time?

A. Yes, I have.

Q. Were you also present in the hearing room when Mr. Faigle testified with regards to his geologic conclusions about this site-specific area of the pool?

A. Yes, I was.

Q. And based upon all that, do you have now your own conclusions and opinions?

A. Yes, I do.

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

EXAMINER STOGNER: Any objections?

MR. CARR: No objection.

EXAMINER STOGNER: Mr. Balke is so qualified.

Q. (By Mr. Kellahin) Before we get into the displays, give me your summary.

A. Well, after review of the South Peterson field, to me -- my conclusions have been that it's a classic, structurally trapped water-drive reservoir and that the structurally high wells will benefit by increase of net pay, increase of secondary dolomitization, which created the porosity and the permeability, and finally the ultimate recovery of petroleum or hydrocarbons in this case.

Q. When we look at a classic water-drive reservoir that has a structural component like this, geologically, can we expect the wells that are located at the highest point in the oil reservoir to be those wells that have the greatest ultimate recovery, as well as those wells that have the longest producing life?

A. That is correct.

Q. Geologically, are we looking at the same reservoir when we compare all the wells that Mr. Faigle showed on his Exhibit Number 2 within Section 31?

A. That is correct. They're all producing from the same reservoir.

Q. All right. I'm excluding for now the well in Section 10, which is in a different feature of the pool, right?

A. Exactly.

Q. All right. Let's turn to your Exhibit Number 1.

A. Okay.

Q. Describe for us what we're looking at.

A. You're looking at what -- my interpretation of the structural top for the Fusselman. There are some differences here, which we'll get to in the cross-section, but it's an erosional -- or it's an unconformable surface that both Mr. Faigle and I are mapping off of. It just depends on which high gamma-ray streak you want to map off and what you're calling the top of the Fusselman. There's the -- Therein lies the difference.

But what we have here is the Enserch Number 1 Well being structurally high to the other wells Mr. Faigle had described as far as having any kind of reserve potential left.

Q. All right. I'm going to show you Mr. Faigle's Exhibit Number 3, in which he mapped off the top of the Fusselman --

A. Okay.

Q. -- and you're also mapping off the top of the Fusselman?

A. Yes, I am.

Q. Let me have you as the expert draw the comparisons and point to any dissimilarities that are relevant.

A. All right. Both Mr. Faigle and myself conclude that the Number 1 Enserch well is the well highest on the structure.

I took a more conservative view -- I guess pessimistic for Phillips in this case -- for the Number 3 Well directly to the south. I just took a higher gamma-ray streak than probably what Mr. Faigle had presented.

And as we work our way down, lower on the structure, we see our Number 2 well and our Number 1A well and Enserch Number 3 Well, all three being offstructure. We both agree on that.

Many points Mr. Faigle and I do agree on, geological concepts.

Q. All right. When we're looking at your Exhibit 1 and his Exhibit 3, when we're looking at the top of the structure --

A. Uh-huh.

Q. -- is there any material difference in the relationship of the two main wells, if you will, the Enserch Number 1 and the Phillips 2A?

A. The significant difference is going to be the structure. We're be looking at -- I believe I have a difference of 69 feet, of a structural difference. Mr. Faigle has 61 feet difference, a difference of --

Q. I think he had 81.

A. Oh, he had 81? Excuse me, you're right, you're correct. I was looking at his other one. Correct, he has a higher structural difference than even what I had put down.

Q. All right. You listened to my discussion with Mr. Faigle about his cross-section?

A. Yes, sir.

Q. Let's go to that cross-section that he presented. It's Exhibit Number 4.

A. Okay.

Q. Do you agree with Mr. Faigle's interpretation and comments as he expressed them to me in response to my questions for Exhibit 4?

A. We have some significant differences in how we interpret these logs.

Q. Tell me the differences.

A. The initial difference is the concept of the subsurface elevation on the bottom of the perforations. I think when you compare both the resistivity, the gamma-ray and certainly the porosity logs here, you'll see a higher porosity on the Enserch Number 1 Lambirth at approximately 7808. There's a high-porosity portion right there, good, solid gamma-ray, which corresponds to our Phillips 2A Lambirth at about 78- -- 7834, approximately. Those two are the same reservoir.

Then, as you look at the Enserch Number 1 Lambirth, you lose all your porosity -- Excuse me, in our Phillips you lose all your porosity. They still have porosity and good reservoir development right there.

I think you should be saying the top of the reservoir equals the top of the reservoir in the Enserch Well and correlate from top to top, not base to base.

Q. All right. Let me focus on that difference.

A. Okay.

Q. Mr. Faigle, in response to my question, says it was of importance to him --

A. Uh-huh.

Q. -- in supporting his conclusion that both wells were comparable in their competition for the oil because he was keying off the bottom of the perforations.

A. That's correct.

Q. Okay?

A. Correct.

Q. You now tell me that the competition is occurring at the top of the reservoir, in the top portions of the perforations?

A. That is correct.

Q. Why the difference?

A. The -- And as Reservoir, Inc., also concluded in their study that Mr. Faigle brought up, you have a lot of significant karsting. Karsting development only takes place in a structurally high position. All your percolating waters and everything have to start at the top and work their way down.

The bottom portions of the reservoir -- or the bottom portions of this karsted event, will not occur on structurally lower positions; it will only occur at the top portion of it, because that's where all the waters and all the secondary dissolution will take place.

So that's why you'll have to go top to top, from reservoir to reservoir, well to well.

Q. When we look at the bottom portions of the perforations in each well --

A. Uh-huh.

Q. -- the porosity values are so low, if I understand you --

A. That's correct.

Q. -- that that is not the point at which these wells are competing?

A. That's correct.

Q. All right. In conclusion, then, the competition is taking place at the top of the reservoir, in the top portions of the perforations?

A. That's correct.

Q. Can you give us a range of values in terms of some type of porosity cutoffs?

A. We've played around with several different porosity cutoffs. I feel comfortable with Mr. Faigle's ten-percent porosity cutoff, and if we quickly look at the

Lambirth Number 1, a quick cross-plot, he's got several from about 7830 on down, cross-plots less than ten percent porosity. Under those cutoffs, you'd say that's not reservoir, that's not pay.

Q. The wells are competing with each other at the top of the reservoir, then, because of the geologic characteristics?

A. Correct.

Q. Then will the well at the highest structural position in the reservoir have an advantage?

A. Yes, it will.

Q. Let's turn to Exhibit Number 2, which is data points in red --

A. They're --

Q. -- and it's identified as a net-pay isopach reservoir?

A. Correct?

Q. All right. Now, we haven't contoured the isopach, but you've got some values?

A. Got some values, and a substantial number of those values were -- after I re-checked them, came from the permanent field rules hearing dated July, 1979, in which a Thomas Brown with Enserch also came up with exact net pay values that I have.

So I tried to agree with Enserch with what

Enserch has described as net pay previously.

Q. Okay. The two wells of greatest concern, I think, to everybody are the Enserch 1 and the Phillips Lambirth 2A?

A. Correct.

Q. All right. What values do you find for those two wells, and what significance do you attach to those values?

A. The values for the Number 1 Enserch well are 44 foot of net pay; for the Phillips Number 2A it's 43. Very similar values. However, the significance here is the structural difference.

Q. All right. In some examples you would have a material difference in net pay between the wells that might explain the difference in ultimate recoveries or rate or some other producing characteristic?

A. Correct.

Q. Here that's not a factor?

A. That is correct.

Q. Let's go to Exhibit 3. Identify and describe that information for me.

A. This is production of the field current through 12 of 1993, again, which corresponds directly to a structurally trapped water-drive reservoir where the wells which are structurally highest benefit from ultimate recoveries being higher. The higher on the structure you're going to be, the better your ultimate cumulative production is going to be.

Q. Geologically, do you see any material difference between the Phillips 2A and the Enserch Lambirth 1?

A. I agree with Mr. Faigle, they're both dolomite, they both have fracture and matrix porosity, and they should be both in communication with each other, the same reservoir.

Q. I don't want to get into an engineering discussion with you, but Mr. Telford described the notion that we have a dual-porosity system here where you've got the fracture system making contribution, and then you have a matrix porosity system that's going to make its own contribution.

A. (Nods)

Q. Geologically, give us your concept of this reservoir.

A. There's been a significant amount of writing recently, based upon karsting and how much significance the fractures have, versus the matrix porosity.

This rock is no different than, say, this building, where the matrix porosity are the rooms, the fracture porosity is the conduits or the hallways.

Your rock volume is going to be greater within your matrix, your fracture system essentially leading you from getting out of one room into the hallway, possibly outside, wherever it goes, or up the well. That's the closest analogy that I could possibly use.

The volume of space or storage capacity of the hydrocarbon within the fractures is significantly less than what's going to be contributed through the storage capacity of the matrix rock.

So the bulk of your storage capacity or the bulk of your hydrocarbons is going to be coming out of the matrix rock and not your fractures. Fractures are only there for conduits.

MR. KELLAHIN: Thank you, Mr. Balke.

Mr. Examiner, at this time I would move the introduction of Phillips Exhibits 1, 2 and 3.

EXAMINER STOGNER: Any objections?

MR. CARR: No objection.

EXAMINER STOGNER: Exhibits 1, 2 and 3 will be admitted into evidence.

Mr. Carr, your witness.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Balke, Let me make sure I understand what we agree about first. You agree we've got a fractured reservoir?

A. There is fracture within this reservoir.

Q. We've got a dual-permeability system -- is that right? I want to be sure I'm using the right terms -- in the reservoir: one in the fractures, one in the matrix?

A. I think your controlling permeability is going to be within your fractures. Your porosity is a function of both the matrix porosity and the fractured porosity.

Q. You do agree, though, we've got a dual system?

A. Yes.

Q. And you've talked about the fractures being primarily conduits in the reservoir; is that a fair characterization of them?

A. Correct.

Q. And when you have two wells that are competing in the reservoir for the reserves, isn't it natural to assume that the competition is going to occur through these fractures, through these conduits?

A. That's one possibility, that's correct.

Q. Do you see a direct contribution in the matrix in this reservoir between the wells, the 1A -- I'm sorry, the 1 and the 2A? Our primary well, your primary well?

A. Contribution as far as -- ?

Q. Competition in the matrix in those two tracts? Or is it primarily just through the fracture systems?

A. I think there's competition both in the matrix and in the fractures.

Q. Now as you've studied this, have you taken into consideration the high water cuts that you're getting?

A. Yes.

Q. Would I be wrong in saying that the fracture system at this time is virtually watered out?

A. That is probably an assumption that's probably correct.

Q. Now, that means that the conduits are virtually watered out; isn't that right?

A. The storage capacity of the conduits are watered out.

Q. If we're going to get the matrix, we've got to -- the production out of the matrix, we've got to do something to move that production to the wellbore; isn't that correct?

A. That's correct.

Q. And if a fracture system is virtually watered out, does it really make any difference which well is higher --

A. Yes, it does.

Q. -- in the reservoir?

A. Yes, it does, because I think the bulk of your production, your primary production is not just solely out of your fractures; it was out of your matrix rock itself from the very beginning.

Q. And now we're looking at it today, we're trying to capture, wouldn't you agree with me, matrix porosity, no matter what it was?
A. Correct.
Q. Mr. Kellahin asked Mr. Faigle about water drive. You indicated this is a structural trap, the reservoir drive mechanism being a water drive.
Is it a bottom or an edge water drive?
A. I think that's more of an engineering question, myself. But -- You know, I don't think I'll be able to answer on that one.
Q. Basically, what we've got is your geologic interpretation based on well-control information, correct?
A. That's correct.
Q. It's the same information that Mr. Faigle has used?
A. That's correct.
Q. We have a situation here where two geologists have looked at the same information and come up with differing interpretations?
A. That's correct.
Q. Not uncommon here?
A. Not uncommon, yes, that's correct.
Q. When did you actually prepare this interpretation?

A. The final interpretation was prepared here just a couple months ago. But I've mapped it when I first -- This was one of the initial fields that I mapped when I first got out to the Permian Basin with Phillips, hired on, about five years ago, and we were trying to see if there was any kind of infill potential here, just basically getting a more up-to-date field study.

Q. And in doing that, did you examine the structural interpretations that had been prepared by Enserch and Phillips geologists who had worked on this project before?

A. That's correct.

Q. And did you integrate that work into your interpretation?

A. Initially, no, I wanted to come up with something that was a little bit different, a little bit fresh.

But then I wanted to see -- Once I had my interpretation finished up, I'd like to see how close I -- how similar I was to everybody else.

Q. If we look at your Exhibit Number 1, it shows it was -- It's got a date on it of 6-94. Is that the date it was prepared, or was it the date of this hearing?

A. It was probably the date of when the draftsman put it together.

Q. Were there any substantial changes made in it recently?

A. I've made several different interpretations, trying to define the reservoir. That is my best interpretation.

Q. Were any changes made to the reservoir interpretation between the Lambirth 1 and the Lambirth 2A in, say, the last three or four weeks?

A. No.

MR. CARR: That's all I have.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin, any redirect?

MR. KELLAHIN: No questions.

EXAMINATION

BY EXAMINER STOGNER:

Q. Let me see if I've got you straight on the karst development.

A. Uh-huh.

Q. You said the voids in this case are going to be larger in the upper portion of the formation?

A. The karsting itself, through percolation of water, dissolution of the dolomite itself, is going to take place because it's just normal waters percolating through on the structurally highest portion of the reservoir.

You'll have more dissolution at your upper points and, as you work your way down, less dissolution down here, simply because there hasn't been as much water percolating through the structure. And thus, your permeability, porosity, storage capacity is going to be smaller.

Q. Okay. With that in note, as water goes through a matrix in some instances, would that water become more acidic and then increase the capability of opening voids in the lower portion?

A. It depends on what the pH was initially with the water. I've not seen a great deal of reservoirs do that, but -- so -- Probably from my experience, I don't.

Q. Okay. Or perhaps percolation upwards of hydrocarbon such as hydrogen sulfide, would that also increase if water was percolating down and the induction of hydrogen sulfide was coming up?

A. Depends on how that hydrogen sulfide was being produced, whether it's bacterial, whether it's being produced right out of -- you know, in the reservoir itself, or through -- if air got into the well itself. You can produce hydrogen sulfide that way too. It just depends on how --

Q. I was thinking more of natural-occurring hydrogen sulfide during the karst --

A. During the karsting, during all the types, place, time, table takes place, yes, you would probably see more H_2S in the higher portions of your structure.

Q. But that would -- That could mean more uniform karsting throughout the formation, or perhaps even larger karsting, not necessarily so, in the lower portion?

A. Correct.

EXAMINER STOGNER: Old habits from my cave days. Sorry.

I'll just mull over the geological information I have.

Any other questions of this witness?

He may be excused.

MR. KELLAHIN: Call at this time, Mr. Examiner, Jack Pickett.

JACK PICKETT,

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. Pickett, would you please state your name and occupation?

A. My name is Jack Pickett. I'm the reservoir engineering supervisor for Phillips Petroleum Company out of Odessa, Texas.

Q. What are your areas of responsibility as an engineering supervisor for your company?

A. I have responsibilities for the whole Permian Basin.

Q. Have you made an engineering study of the facts of importance to you as an engineer concerning this Application?

A. Yes.

Q. Prior to this case, were you involved in and knowledgeable about Phillips' production in this pool?

A. Yes.

Q. Based upon your studies, have you reached certain engineering answers and conclusions with regards to the Enserch Application?

A. Yes.

MR. KELLAHIN: We tender Mr. Pickett as an expert petroleum engineer.

EXAMINER STOGNER: Any objection?

MR. CARR: No objection.

EXAMINER STOGNER: So qualified.

Q. (By Mr. Kellahin) Mr. Picket, Enserch has requested the Division Examiner approve for this pool an increase in the oil allowable to 500 barrels of oil a day. Do you have an opinion on that request?

A. I think it would damage Phillips.

Q. Why do you say that?

A. Basically they're updip. It's a water-drive reservoir, and we're downdip, and it would bring water into our downdip wells faster.

Q. Simple as that?
A. Yes.
Q. One of the contentions made by their engineering witness, Mr. Telford, was that he was going to be able to increase ultimate oil recovery from the reservoir?
A. Yes.
Q. Do you agree with that conclusion?
A. No, I do not.
Q. Why don't you agree?
A. We've tried essentially what they're saying they're going to do by putting two subs in on our wells, and it didn't work.
Q. The existing oil allowable is 267 barrels of oil a day. The primary well that benefits from the increase would be the Enserch well?
A. Yes, the only well that would benefit from any increase.
Q. All right. Have you considered the option or the alternative of how long you would like to continue with the existing rules before any allowable increase or adjustment is made?
A. Yes.
Q. And what have you concluded?
A. In three years, Phillips' wells will probably be uneconomic, and at that time Enserch can do whatever they

like.

Q. Okay. Do you see any disadvantage as a reservoir in postponing the allowable increase until you have reached the economic limit of your Lambirth 2A well?

A. No, I do not.

Q. Under the current, existing rules by which these two companies have competed for the last 16 years, which is an allowable limit of 267 barrels of oil a day, have you calculated and determined how much of the original oil in place in the pool that Enserch has recovered out of their Lambirth Number 1 Well?

A. Yes.

Q. And what is that number?

A. Forty percent of the oil in place.

Q. In the total pool?

A. Yes. Thirty-eight percent to date.

Q. Let's look at some of the specifics that got you to those conclusions.

If you'll turn with me to Exhibit Number 4, let's look first of all at the Phillips Lambirth A Number 3 Well. This is the south offset to the Enserch Number 1. What have you shown on this display?

A. This is a production plot for Phillips' Lambirth A Number 3.

Q. Color code?

A. Yeah, the black curve is the oil in barrels per day, the blue is the water in barrels per day, and the red is the GOR.

Q. When we're looking for a determination of how many of the producing wells in the pool be going to benefit or have the opportunity to enjoy an allowable increase, would this be one of those wells?

A. No, I don't think even Enserch would argue with that because this is a low-productivity well. It makes about 20 or 30 barrels a day, one barrel of water. It's in a different type of rock than the rest of the reservoir; it's in the lower-perm rock. And --

Q. All right. We get 20 barrels of oil a day out of this, and how much water?

A. One barrel.

Q. Okay. Let's look at Exhibit Number 5. Which well is this?

A. This is again a production plot for Phillips' Lambirth A Number 1, a little bit different presentation than the prior curve. The black is the same, is oil in barrels per day. The red is gas in MCF per day. And the blue curve is the water-oil ratio, simply the water divided by the oil production.

Q. All right. So I can draw this into perspective, I'm going to show you Enserch Exhibit 8, which I'm going to hand to you, and let's use both your 5 and their 8 to talk about the same well.

On the Lambirth A1, what in fact is the correct date at which the submersible pump was installed?

A. October of 1992.

Q. And the date that was testified to by Mr. Telford? What day was he using?

A. He's got something in 1990, middle of 1990 or something like that.

Q. Does that error on his part in identifying the date at which the submersible pump was installed in this well have significance?

A. I think it totally negates all his testimony about whether there was any increase in reserves when the submersible pump was installed on the Lambirth A Number 1.

Q. Draw us through the analogy that causes you to reach that conclusion.

A. If you'll note, the water-oil ratio curve, the blue curve on Phillips Exhibit Number 5, before the submersible pump was installed in October of 1992, you can see it varies from -- in the prior year or two years, between six and ten, with an average of about eight or nine, the water-oil ratio.

After the submersible pump was installed in October, 1992, you see almost an immediate increase in the water-oil ratio to something like 15, peaks up as high as 40 or 50, and it currently is running about 50, 55, which would -- You also see a rapid dropoff in the oil -- You see an initial increase in the oil production. Later on, it drops off within about six months, indicating that all we really were doing is accelerating the oil that we were going to get before anyway.

Q. Any doubt in your mind that that's what's happening here in this well?

A. No.

Q. Has the pump been put in there long enough and run a consistent period of time in which you can conclude as a reservoir engineer that this is simply nothing more than rate acceleration?

A. That's correct.

Q. All right. If the hypothesis in the 1979 SPE paper is correct, then it doesn't work in this pool, does it?

A. Not in this well.

Q. All right. Do you have another example of where this was tried in this pool?

A. Yes, the next exhibit.

Q. Let's look at Number 6.

And while we're doing that, I want to give you Mr. Telford's Exhibit -- it's his Exhibit Number 9. And we're looking at your Exhibit Number 6.

Did Mr. Telford have the correct date at which the submersible pump was installed in your well in this --

A. No, he was incorrect on this well also. He shows it to have occurred in about mid-1991, with the actual date being February of 1992.

Q. Is that difference or is that error of significance?

A. Yes, because just like the Lambirth A Number 1, the data that he presented showing a decrease in water-oil -- or in water cut, after the submersible pump was installed, actually did not occur. And so there's no evidence of any increased reserves, as he presented.

Q. When we plot on the data the correct point in time when the submersible pump, in fact, was actually installed of February, 1992, what does the data show you?

A. If you look at the -- There was a significant increase in the oil production when a submersible pump was installed in February of 1992.

And on the water-oil ratio curve it was running about seven or eight before, and runs slightly higher after the submersible pump was installed in February of 1992, runs about eight or nine. And in about six months it's well over ten.

Q. What's your conclusion about this well? Are we increasing ultimate oil recovery in this well, or is this simply rate acceleration?

A. From the way the production was -- It's fairly erratic before the sub was installed; it goes up and down. But you could probably say it was almost constant.

Afterwards, you've got a real good decline, so it appears that all we have is rate acceleration, no new reserves.

Q. Okay. Let's look at the next exhibit. It's your Exhibit 7. It's on the Enserch Lambirth 1. And at the same time I'm going to show you Mr. Telford's exhibit for Enserch, which is marked Number 7. Number 6. Enserch Exhibit Number 6, corresponds to your plot on exhibits.

Before we look at Mr. Telford's exhibit, let's look at yours. Tell us what you see in the plot.

A. Basically, before the submersible was installed, the same comments that Mr. Telford made are valid. It was a top-allowable well until late 1985, 1986.

This is the best example in the field of the water drive because of the constant GOR, fairly smooth production data.

Q. Okay. Let's look at his Exhibit Number 6 now. In response to my question he said that if his well was affecting yours, with the increase in withdrawals now, then correspondingly he should have seen a bump in his production when you put your submersible pump on.

That was paraphrasing his statement, but I think it's accurate.

A. Yes.

Q. All right. Do you have an explanation as to why there is not an apparent effect on the Enserch well when you put the submersible on your 2A?

A. Basically because they're updip from us, so our well would not affect their well.

Q. Simple as that?

A. Yes.

Q. All right.

A. In this time period that we've -- since we've had our wells on submersible pump.

Q. Okay. Do you have a copy of Mr. Balke's structure map?

A. Yes.

Q. All right, let's look at it. As a reservoir engineer, tell me what you see in terms of these two wells competing for the remaining oil in the pool within this particular area.

A. I see their well being at the top of the structure, pulling the hardest, having the most remaining oil production, and for every barrel that they pull out it's going to -- of fluid, it's going to cost water to encroach on all the downdip producers that are in the water-drive area, pretty much the Phillips Lambirth A Number 1 and Phillips Lambirth A Number 2.

Q. Is there any doubt in your mind as a reservoir engineer that if the Examiner increases the allowable, it will do so at the expense of your share of oil production?

A. No doubt at all.

Q. Okay. Let's look at your Exhibit Number 8. Identify that tabulation of information for me.

A. This is simply the latest well tests that were made available for the four wells in the area of interest.

Q. All right. We're looking at the far-right column, we're dealing with water-oil ratios as opposed to water cuts?

A. Yes, it's simply another way of stating the production.

Q. All right. Let's look at the concept of the water-oil ratio and have you tell me what those values are for each of these four wells.

A. Okay. For Phillips' Lambirth A Number 1 the current water-oil ratio is 51.

The Lambirth A Number 2, it's 17.

The Lambirth A Number 3, which has a very low water cut or -- in the low water-oil ratio, but it's really in a different type of rock and is not in the area of concern.

And then the Enserch-operated Lambirth Number 1 has a water-oil ratio of eight. And what that tells me is that the highest well has the lowest water-oil ratio.

Q. That's consistent with the positioning of these wells in a water-drive reservoir, isn't it?

A. Yes.

Q. You would expect that the higher structural well would have the lowest water-oil ratio?

A. Yes.

Q. All right. When we look at these values, as a supervising engineer for your company, at what point in that ratio do you then conclude, if you do at all, that the well is no longer economic?

A. Generally, at about a water-oil ratio of 40 a well is uneconomic.

In the case of the Lambirth A Number 1, it's continued to produce until the submersible pump needs to go down --

Q. All right.

A. -- and that's the only reason it's still producing. If it needs any maintenance work, it will be shut down.

Q. All right. The A1 is downstructure. It's really beyond its economic limit. It will continue to produce until there's a pump failure, and then you're done?

A. Right.

Q. Okay.

A. And there's still a significant difference, though, in the water cut of the four producing wells in the area of concern.

Q. Well, and that's what I want to focus your attention on. The Lambirth A2 has got a water-oil ratio of 17?

A. Yes.

Q. And if your economic cutoff is 40, what does that tell you?

A. It's got some life left.

Q. And your estimate of life a while ago was something around three years?

A. Yes.

Q. Would you expect that to be watered out before the Lambirth Number 1 operated by Enserch?

A. Yes.

Q. And it has a water-oil ratio of eight?

A. Yes.

Q. Okay. When we direct your attention to the Enserch Lambirth 1, have you looked at that production?

A. Yes.

Q. Have you tried to determine what the volume of production from that well means as you compare it to production of other wells in the pool?

A. Yes, I have.

Q. Let's turn to your display. It's Exhibit Number 9. Describe for us what you've done.

A. This exhibit is entitled "Ensearch [*sic*] Lambirth Number 1". It's had cumulative production to date of 953,000 barrels of oil, a little over a BCF of gas and about 37,000 barrels of water.

That accounts for 38 percent of the total oil production that has been produced from the South Peterson-Fusselman field to date.

Q. All right. When we take total oil production from the pool, where did you get that number? The total oil production from the field -- or the pool -- is a reported volume?

A. Yes, by the New Mexico Engineering Committee.

Q. All right. And you've determined that this single well has produced 38 percent of the total pool's oil production?

A. Yes.

Q. Okay. What's the next number?

A. The next number is the percentage of the acreage and well count that the Lambirth Number 1 represents for the total pool, eight percent.

Q. Okay. What's the next one?
A. Twenty-two percent is the -- simply the percentage of the pay that our geologist, Scott Balke, showed that the Lambirth Number 1 has in relation to the rest of the wells in the pool. It has 22 percent of the net oil pay.
Q. Okay. And the last one?
A. We -- Using that net oil pay map that Mr. Balke prepared, I calculated that the 80-acre producing unit on the Lambirth Number 1 has about 20 percent of the oil in place on it.
Q. Under the current rules for 267 barrels of oil a day, the well with 20 percent of the original oil in place has already covered 38 percent of the total pool production?
A. That's correct.
Q. What happens if the allowable's increased?
A. Their percentage will go up even more, of the production.
Q. Where did the contribution come for production in this well that's in excess of its share of the original oil in place?
A. From the offsetting tracts.
Q. Have you tried to determine if there's an engineering explanation for the production totals for this

Enserch well?

A. Yes.

Q. As part of your preparation in this case, did you go back and review the prior transcripts of the Division concerning the establishment of the pool rules?

A. Yes.

Q. And in the course of that investigation, did you find engineering evidence that supported a reason for why this well is doing so very well?

A. Yes.

Q. What did you find?

A. In the 1979 hearing to make the field rules -- the temporary rules permanent for this field, a Mr. Leonard Kersh with Enserch -- I believe he was presenting engineering testimony.

Q. You're looking at Exhibit 10 now?

A. Yes.

Q. All right, sir. And page 21 of that transcript and page 22 represent part of Mr. Kersh's testimony with regards to engineering data for this well?

A. Yes, and if -- I'll just summarize the point that he was making there, at the bottom of page 21 and then on to the first page of 22, was that they ran -- Enserch had conducted a reservoir-limits test and had determined that their Enserch Lambirth Number 1 well was affecting 830 acres.

Q. The reservoir-limits test that Mr. Kersh had presented on behalf of Enserch in this hearing resulted in a drainage equivalent of 830 acres?

A. Yes.

Q. The test upon which he made that conclusion is what type of test?

A. A reservoir-limits test.

Q. All right. Is this a pressure-buildup or a pressure-drawdown or some other kind of test?

A. It's a type of pressure-drawdown test.

Q. Did you examine the information to satisfy yourself that it appeared to be accurate and reliable in terms of testing procedures?

A. Yes.

Q. Do you find any fault with how that was done or how his presentation was made on that aspect?

A. No, it appears to be a correct interpretation.

Q. All right. Let's look at Exhibit 11. If you look at simply a circle with this well at the center and scribe an area that includes 830 acres --

A. Yes.

Q. -- what does it show you?

A. It shows its affecting almost the entire Section 31 and lots of other acreage.

Q. All right. At least theoretically, if you assume radial drainage, then the Lambirth Well is going to be affecting every well around it?

A. Yes.

Q. Have you tried to take this information and to fit it within the size and the shape of the reservoir that Mr. Balke has identified and presented to the Examiner?

A. Yes, it would actually be affecting a lot more of the reservoir than this simple circle shows, because some of the circle is drawn outside the pinchout to the south, and so it actually affects almost the entire reservoir.

Q. So this one well by itself is going to affect all the wells and has affected all the wells in its immediate vicinity?

A. Yes.

Q. And if the allowable is increased, it will continue to do so?

A. Yes.

Q. Have you tried to quantify the amount of remaining recoverable oil that you still have an opportunity to produce as long as the Examiner doesn't change the rules for your Lambirth 2A well?

A. Yes.

Q. Let's look at Exhibit 12 and have you describe that for me.

A. Okay. I call this an economic limit plot for the Lambirth A Number 2 Well. It's got the historical production, the oil in green, the water-oil ratio in blue and then the gas production in red.

I've extrapolated the oil production until a water-oil ratio of about 40 was reached in early 1997, which I think equates to about a 17.5-percent decline rate on the oil and gives us a remaining life of the Lambirth A Number 2 of about three years.

Q. Have you estimated the remaining recoverable oil in terms of a volume --

A. Yes, and that --

Q. -- that's available to this well?

A. Yes, and that would be about 89,000 barrels of oil.

And this actually represents the minimum, because the oil-production decline rate will probably increase when the effects of the Enserch Lambirth Number 1 increased withdrawals are shown.

Q. Let me direct your attention, Mr. Pickett, to the Enserch Exhibit 7 which Mr. Telford introduced. It was the tabulation of the May and June data from the two submersible pumps on his Lambirth Number 1 Well.

He says he could look at that plot and he concluded that he was seeing enough information to cause him to conclude that that was going to be an increase in ultimate oil recovery. That's what he said, wasn't it?

A. Yes.

Q. Do you agree?

A. No, I do not.

Q. What do you see?

A. It's too early to tell, really, in the -- I'm not sure if this was actual production data or just test data, and -- so -- I think he -- I believe he said it was test data, which isn't as good as the actual production, the monthly gauge reports, and also there just hasn't been enough time to show up something significant.

Q. No doubt in your mind as a reservoir engineer that that's not enough information to base any reasonable engineering judgment?

A. Right.

Q. You can't calculate or estimate whether that's rate recovery, accelerated or increasing ultimate oil recovery?

A. Right.

Q. Can't do either one?

A. Right.

Q. One item we touched on briefly with Mr. Telford is that the Enserch 1 certainly could produce up to 360 a day, and that the Phillips 2A might have a chance to produce something in excess of the current oil allowable.

A. Yes.

Q. What does that well do now?

A. Let me refer back, just a moment.

Q. Yes, sir.

A. About 115 barrels of oil a day and 1900 barrels of water per day.

Q. So you're substantially below the current oil allowable?

A. Yes.

Q. Is there anything you can do within the economic limits of your remaining oil production so that you could compete with the Enserch well if the Examiner chooses to increase the oil rate?

A. we could shut in immediately our Lambirth A Number 1 Well, and by doing that we could handle another 500 or 600 barrels of water through our SWD system. So that would give us about a 30 percent we could see in the Lambirth A Number 2 well, which might bring us up to 140, 145 barrels of oil per day.

Q. Okay. Do you have an engineering explanation as to why the hypothesis in the SPE paper doesn't work in this portion of this pool? What's happening?

A. Well, I think it's still -- Water drive is a significant factor, both edge water and bottom water drive, probably, and that something -- somewhat of an inhibition process is still going on where water is displacing oil from the matrix, and that takes some time to do.

Q. What's your recommendation to the Examiner?

A. I would leave the field rules as is for about three years, and then once the Phillips well goes uneconomic in about three years we'd have no objection to changing the allowable.

Q. Do you see any adverse consequences to Enserch if this Application is denied?

A. No.

Q. If this Application is approved, do you see any corresponding effect on Phillips?

A. Yes, I feel Phillips would lose oil.

Q. And as a reservoir engineer for your company -- in fact, as an engineering supervisor, do you see definitive evidence that would cause you to believe that ultimate oil recovery is being increased if we increase the withdrawal rates in this reservoir and jump the oil allowables?

A. No, I see no evidence of that.

Q. What would you do with this Application?

A. Turn it down.

MR. KELLAHIN: All right, sir. Nothing further.

We move the introduction of -- exhibits which

I've lost track of. It's 4 through 12, I believe.
EXAMINER STOGNER: Any objections?
MR. CARR: No objection.
EXAMINER STOGNER: Exhibits 4 through 12 will be admitted into evidence.
Thank you, Mr. Kellahin.
Mr. Carr?

CROSS-EXAMINATION

BY MR. CARR:
Q. Mr. Pickett, you'd agree with me, would you not, that this reservoir is nearing the end of its producing life?
A. It's got a few more years left.
Q. Out of a 20-year life-span, we're down to perhaps three?
A. I think the Enserch well should go on farther than three.
Q. Would you agree with me that the reservoir is substantially watered out at this point in time?
A. No.
Q. You would not? Water cuts don't tell you the reservoir is substantially watered out?
A. I guess it depends on your definition of "substantially watered out".
Q. Ninety-five percent water cut?

A. Watered out, to me, is uneconomic, and there are still economic wells left.

Q. So in determining whether or not the reservoir is watered out, you don't look at the water cut?

A. That tells you if the well's economic or not.

Q. So just because we're over 95-percent water cut on some of these wells, to you, doesn't say the reservoir is substantially watered out? Just 100 --

A. It has watered out or is nearing watering out --

Q. When we water out this reservoir, don't we really water out the fracture system first?

A. I think it probably happens at the same time.

Q. Water out the matrix at the same time we water out the fracture?

A. Yes.

Q. Now, do you have a -- in your opinion, a bottom water drive or an edge water drive here?

A. Combination.

Q. So if we have a bottom water drive moving up in the reservoir, it's watering out the matrix at the same time it's watering out the fracture system?

A. Yes.

Q. So below -- If we have water in the fractures, is it fair to assume that offsetting it in the matrix, we've also watered that out?

A. Can you repeat that?

Q. I'm just trying to understand what you're saying. I mean, if we have, say, a bottom water drive, as that moves up --

A. What kind of water drive?

Q. A bottom.

A. Oh, okay.

Q. As opposed to an edge.

A. Yes.

Q. But as the water contact comes up to the reservoir, you're saying that we're watering out the fractures at the same rate as the matrix?

A. Yes.

Q. Okay. When we look at the overall presentation in this case, isn't Phillips' primary concern with its Lambirth 2A well?

A. Yes.

Q. You're concerned about the potential damage to that well?

A. Yes.

Q. When we look at like your Exhibit Number 4 on the Lambirth A Number 3, that really is not providing us with information that's meaningful to this hearing; it's outside the fracture system we're talking about, is it not?

A. I think that was our point, was that this well was outside the area of concern.

Q. Now, you have also taken a look at the SPE paper that has been discussed by Mr. Telford?

A. Yes, that's right.

Q. You don't think it applies in this reservoir?

A. We tried it, and it didn't work.

Q. If we go to your Exhibit Number 5 and the testimony that you offered related thereto from Enserch Exhibit Number 8, both of these relate to the Lambirth 1A?

A. Yes.

Q. You noted that on this exhibit Enserch had placed the installation of the submersible pump at the wrong time?

A. Yes.

Q. In fact, it was installed in October of 1992, as opposed to 1989, as shown on this exhibit?

A. Yes.

Q. If I look at this exhibit, in late 1989 there's a substantial increase in the oil production and a corresponding drop in the water cut. Do you see that?

A. Yes.

Q. Can you explain to me what happened that caused that to occur?

A. No, I cannot.

Q. So that's just something that happened in just the history of the producing well?

A. Yes.

Q. Do you know if there was a -- There was a beam pump on the well at that time?

A. Yes.

Q. Do you have any information or pressure information that would suggest that there was any change in the way you were operating the well at that point in time?

A. We could have run fiberglass rods, acidize the well, something like that. I don't recall.

Q. What would fiberglass rods do?

A. Increase the lift.

Q. If they increase the lift, would that also increase the -- That would be also basically a high-volume lift method, would it not?

A. On a slightly smaller scale it would.

Q. So at that point in time, if you put fiberglass rods in the pool, you'd have increased the lift capacity, and that would have shown the decrease in the water cut and the increase in oil production?

A. If we did, and I have no knowledge that we did.

Q. Did you look to see?

A. Yes.

Q. And you don't know what you found?

A. I don't recall.

Q. If in fact that was the result of fiberglass rods, improving the lift capacity, wouldn't in fact we have high-volume lift which resulted in increased oil and lower water cut?

A. For a little while.

Q. Okay. We go on and then we come along and you install a submersible pump in October of 1992?

A. Yes.

Q. Why did you do that then?

A. We did an engineering study of the field and saw that that was the economic thing to do.

Q. Economic, as opposed to continuing with the beam pump?

A. Yes, we could make money by putting in a sub.

Q. Were you trying to at that time increase your lifting capacity in that well?

A. Yes.

Q. In fact, did you achieve that?

A. Yes.

Q. After installing that pump, didn't you receive for a short time both an increase in the oil production and a decrease in the water cut?

A. I believe we saw an increase in the oil production, but I don't see a decrease in the water cut or water-oil ratio.

Q. Last part of 1992 you don't see a drop in the water cut?

A. Not below what it was from before the sub.

Q. Wasn't it your testimony that by going to the high-volume lift you weren't actually recovering any additional oil?

A. Yes.

Q. You're not going to increase recovery, in your opinion?

A. Ultimate recovery, yeah.

Q. If we look at just the exhibits, the production history on the Lambirth 1A, and if the increase in 1989 was because of fiberglass rods and a better lifting capacity, haven't you actually changed the decline level for the well, for the oil production? Don't you have a higher decline or production level, against which you apply your decline?

A. Yes, if that occurred.

Q. And if that occurred, wouldn't that be consistent with the SPE study?

A. Well, I don't really see a change in the -- that much of a change in the water-oil ratio.

Q. After December, 1990, you do see a higher --

A. Well, let me --

Q. -- oil production rate do you not?

A. Yes, but it -- and it goes on a pretty good decline.

Q. And that's a higher decline, even though it may be at the same percent, than you were experiencing prior to that time?

A. The production is very erratic before that date, 19- --

Q. Is it not also lower?

A. The production before?

Q. Before that date is it not consistently lower?

A. Yes.

Q. If we go to the exhibits on the Lambirth 2A, again we have a wrong date for an installation of the submersible pump, correct?

A. That's correct, you had -- Enserch had the wrong date.

Q. Do you know where we got those dates?

A. I assume -- From Mr. Telford's testimony, he said he was assuming it from the production plot.

Q. Okay. If we look at these exhibits, if we look at the 2A and we go back to the point in time where Mr. Telford has surmised that you installed this submersible pump, at that time don't we see an increase in oil production?

A. What is that time?

Q. If we go to, Mr. Pickett, Exhibit Number 9, Enserch Exhibit Number 9 --

A. I don't have a copy of that, I don't think. Maybe I -- Yeah, I think I have Number 9.

Q. Okay. If you look at that exhibit, Mr. Pickett, you can see a line that shows where Enserch surmised you had installed this submersible pump. Do you see where the arrow points?

A. Yes, to --

Q. At that point --

A. -- about mid-1991?

Q. Yes, sir. At that point in time, don't we see an increase in oil production and a corresponding drop in water cut?

A. Yes.

Q. Was there, to your knowledge, any change in the way you were operating this well that would have caused the oil to increase at that time and the water cut to drop?

A. I have no knowledge of any operating changes.

Q. Did you check to determine if there were any at that time?

A. Yes.

Q. Is this just a natural-occurring phenomenon, that you would experience this in the reservoir?

A. It's not totally unexpected. I think you could look at all the production plots. They're fairly erratic like that.

Q. And have you seen other examples where oil production rates take a jump and then seem to start at a new higher level, maintaining a decline rate?

A. Yes.

Q. That's common in your experience in this reservoir?

A. Yes.

Q. If I understood your testimony it is, once the Lambirth 2A is plugged or you cease producing it, then you have no objection to what's done with the reservoir; is that right?

A. That's right.

Q. Once you no longer have an interest, you don't care?

A. That's right.

Q. Water cuts have been a problem in this reservoir from the beginning, have they not, Mr. Pickett?

A. Yeah, water production has been a problem.

Q. And you required both of the primary operators -- we don't know about Mr. Bledsoe, but both of the primary operators to try and manage this water problem throughout the producing life of the reservoir?

A. Yes.

Q. In that regard, has any thought been given to prudent operating practices beyond this point, other than just producing these wells until we -- our equipment fails or they're no longer economic and just shutting them down? Has Phillips looked at that in a broader sense, or have you just looked at maintaining your production until you hit these economic limits?

A. I'm not sure if I understand the question.

MR. KELLAHIN: Well, I'll object. It's irrelevant.

MR. CARR: I think it's -- We're talking here about a method to try to efficiently produce the reservoir in its waning years. And we have testimony that says, we have a couple of wells, when the equipment fails on one we're through, when we hit the economic limit we're through, and do what you want.

My question is legitimate. Have you looked at this reservoir, in terms of managing it, other than just producing your wells to economic limits and then goodbye? That's an appropriate question, and he can say they have or they have not.

EXAMINER STOGNER: This time I agree with Mr. Carr, and since we are talking about the relevancy of developing the pool to its potential, I'm going to override your objection.

Mr. Carr?

Q. (By Mr. Carr) Do you understand my question, in all of that?

A. Oh, yes. I think the answer is yes, we've looked at managing the reservoir.

Q. Have you come up with anything other than just producing it to these economic limits and then just shutting it down?

A. We have a few other ideas in -- for the reservoir.

Q. And are you -- was high-volume lift one of these?

A. When the Lambirth A Number 1 goes down, we'll -- our thought is that we can increase the lift from the Lambirth A Number 2.

Our SWD facilities are currently at 100 percent of capacity, so we can't dispose of any more water at this point. But when the Lambirth A Number 1 goes down, we could dispose of more water and produce more fluid from the Lambirth A Number 2.

Q. So when you can dispose of the water, you would then consider additional high-volume lift on the A Number 2?

A. Yes.

Q. And that's dictated by water disposal, not reservoir management?

A. I consider water disposal part of reservoir management.

MR. CARR: I think that's all I have, Mr. Pickett. Thank you.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin, any redirect?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Mr. Carroll, do you have any questions?

MR. CARROLL: Nothing, Mr. Stogner.

EXAMINATION

BY EXAMINER STOGNER:

Q. I believe, Mr. Pickett, your testimony about the Lambirth Number 1 as far as increased production, any increased production from anything above -- What is it? 267 barrels of oil per day or the present allowable?

A. Yes.

Q. -- would essentially be from other acreage, as opposed to what is allowed them from their 80-acre drainage or -- Does that make sense?

A. Yes, in a way. I mean, the oil they're producing right now is sort of at our expense, any oil they make, since they're updip and we're downdip. But that's just a built-in, I guess, advantage they have.

Q. And so anything above that, even one barrel, would be one additional from what would be acceptable with

Phillips?

A. Yes.

Q. Does any of the Phillips wells, do you feel, have any -- could they gain by an additional allowable or increased production from its -- from the present allowable?

A. No, we have the same 5-1/2-inch casing that Mr. Telford testified his Lambirth Number 1 does, and we could put the same size submersible pump in that they would want to get their 500 barrels a day, but with our higher water cut that doesn't even get us over 200 barrels a day, putting in the largest submersible pump commercially available at the moment, even if we had more SWD capacity.

EXAMINER STOGNER: I have no other questions for Mr. Pickett at this time.

You may be excused.

Mr. Carr, do you have anything to present further?

MR. CARR: No, sir.

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: That concludes the presentation of our evidence.

I'm happy to submit a draft order or try to summarize this for you. We're here at your please, and whatever you desire us to do, we're happy to --

EXAMINER STOGNER: Well, let's see. First things first.

What about the additional notification, Mr. Carr? How do you propose we handle that?

MR. CARR: May it please the Examiner, the case will have to be continued to permit us to provide notice to Bledsoe and any other operator in the Fusselman --

EXAMINER STOGNER: And that would be continued -- I don't necessarily see that it needs to be re-advertised.

MR. CARR: I don't think that it had to be, but we do have to provide notice by regular mail.

EXAMINER STOGNER: So this would be continued to the -- What? July 21st?

MR. CARR: Yes, sir.

EXAMINER STOGNER: Okay. With that, I'd like to see, yes, a rough draft order from each of you.

Would you care to make closing statements at this time?

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: Okay, Mr. Kellahin, I'll allow you to go first, and then Mr. Carr.

MR. KELLAHIN: Just briefly, Mr. Examiner, we're talking principally of two wells competing with each other, the Phillips 2A and the Enserch Lambirth Number 1.

If you increase the oil allowable above what it is now, if you do the 500 barrels a day, Mr. Pickett has just told you that the configuration of his wellbore is limited by the size, 5 1/2-inch. And so if he is to put comparable lifting equipment in his well, that Mr. Telford is doing, the Phillips well can't even make the current allowable. What happens is the inequity between the parties continues to broaden.

Enserch enjoys a natural advantage in the reservoir about having the highest structural position. They've already recovered 954,000 barrels of oil, which is twice the percentage of oil in place in the reservoir that was their share. It represents 38 percent of the total oil produced in the entire pool.

They're getting greedy. They want more than their share, and they want to take it from us.

It's not my burden to prove their case, and they've failed to meet their burden.

Mr. Telford comes in with an SPE paper that has a hypothetical issue that you can produce an oil reservoir that has an active water drive by creating a pressure drawdown in the reservoir and further bleed the matrix.

Mr. Pickett's tried it in the field, in this pool, in this reservoir, in close proximity to the Enserch well. He still can't make the current oil allowable. So if there's any contribution, it certainly doesn't justify anything in excess of what we have now.

He says what he's seeing, as an experienced reservoir engineering supervisor, is simply rate acceleration. That's what those production-decline curves show him.

With all due respect to Mr. Telford, I think he's made a substantial and critical error in his conclusions, particularly when he misplots the point in time where the submersible pump is put on both of the Phillips wells. He misplots it, misreads it, and comes to the wrong conclusion.

In addition, if you look at his own well, he hasn't proved his own case. What does that test show you? It's not definitive of anything. It doesn't tell you if that's improving ultimate oil recovery. He doesn't attempt to quantify what additional oil recovery is going to take place in that well. He can't even use 500 barrels a day. He gets 360, and he wants more. Enough is enough.

Our testimony, which is undisputed, absolutely unrefuted, is that we can wait until the Phillips well is abandoned and Enserch can come back and get all the rest. They're going to get it anyway. Let them postpone that so they don't take it from us.

Their obligation is to prevent waste and to protect correlative rights. They haven't made a waste case, and all they've done is validate our proof that they're taking our oil. They enjoy a natural advantage.

Let's leave the rules the way they are, the way they have been the last 16 years, and let's just finish this out without making us contribute our oil for their production.

There's not just a difference of opinion between geologic experts. Mr. Carr wants to dismiss this as a point of difference between two geologists looking at the same data. Look at the data. Get Roy or somebody to look at the logs with you. Look at the porosity values on those two logs. You can come to your own conclusions.

Mr. Faigle is wrong. The point of the logs is, the highest values are in the top of the reservoir. It's nonsense to suggest that these wells are competing equivalently at the lower portion of the reservoir.

Make your own analysis. Look at the data and reach your own conclusions, and when you do, we think you're going to agree with us: They have not met their burden of proof, and the Application ought to be denied.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Carr?

MR. CARR: Mr. Stogner, Mr. Kellahin just stood before you and said, Just let it run out. Let it run out, and when we've gotten what we can, then let them do what they want.

We come before you today because we're convinced that other than just letting things run out when you get to this point in the life of a reservoir, there comes a time when you try and manage it, when you try and do what is necessary to maximize your recovery from the reservoir. And I will tell you that just letting it run out is not the prudent way to operate a reservoir, nor, in my opinion, is it consistent with what the Conservation Commission is directed to do.

Enserch stands before you, yes, proposing to increase allowables. And the reason is to maximize ultimate recovery from the reservoir.

Mr. Kellahin says, Yes, Mr. Stogner, you look at the evidence. Well, we agree on that. I'd like you to look at the production curves, and when you see what happens -- When we increased our lift capacity, we saw an increase in oil, and we saw a drop in the water cut. And you look at the other exhibits, and when it was either through a beam pump or perhaps fiberglass rods or through a submersible pump, you still have a still have a decline curve, but it's at a higher level.

And what we are doing is extending the economic life of the reservoir, and we will recover more oil. But to do it, you've got to do it at an appropriate time. It's like a waterflood: You get to a point where it's too late to effectively waterflood.

If you look at the SPE paper, which albeit Phillips discounts, you do this before you have the 95-percent water cut. And we are there, or nearly there. And if we're going to do it three years, it's not just something that is waited out for Phillips, waited out for Phillips to finish off. It may be too late for some of these necessary measures to effectively be implemented.

There are some things we don't have a dispute on. It's late in the life of the reservoir. We've got a highly fractured reservoir. The geological witness for Phillips agrees with us that they're watered out. We don't know what "watered out" means from an engineering point of view.

But the data shows that what we've got is really three wells that are of significance: the Lambirth Number 1, our well; the 2A north of it, Phillips' well; and the 1A. And as we have looked at the producing lives and the histories of these wells, we have seen, when you apply high-volume lift, you get the result that the SPE paper suggests we will. And Phillips says that's not true.

But even their expert engineering witness, when he comes before you, Mr. Stogner, says, as soon as the Number 1A is dead we're applying high-volume lift to the 2E [*sic*]. That's what he told you. And the only logical reason to do it is, you'll improve your recovery when you do it.

So that's why we're before you, because we think what they want to do later on their 2A needs to be done reservoir-wide right now. That's why we've come here before you here today.

They talk about reservoir damage. Mr. Kellahin says, Oh, they've had a great well. Yeah, we do; we have the discovery well. It remains the best well in the pool, and it has produced a lot.

But correlative rights, by definition, doesn't say, you go back and look at what we produced yesterday. It requires that we go forward, cognizant of waste, to effectively produce the reservoir and give everyone their opportunity to produce their share.

We submit to you we have come before you with an appropriate plan to manage this reservoir and to do it today, and that if this Application is denied, it isn't saying, come back later when nobody else cares; it's saying, no, don't manage the reservoir, waste the reserves.

EXAMINER STOGNER: Thank you, Mr. Carr.

Anything else further in this case today?

Being none, this case will be continued to the Examiner's hearing scheduled for July 21st. This extension is due to notification requirements, and I don't believe it will be necessary to take any additional testimony at that time.

Between now and then, preferably around the week of that 21st hearing, if I can get rough orders from both of you I would appreciate that.

With that, hearing adjourned for today.

(Thereupon, these proceedings were concluded at 4:10 p.m.)

* * *

I do hereby certify that the foregoing is
a complete record of the proceedings in
the Examiner hearing of Case No. 10994,
heard by me on 23 June 19 94.
, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL July 2, 1994.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1994

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 ENSERCH EXPLORATION, INC.

CASE NO. 10,994

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

ORIGINAL

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MAR - 6 1995

Oil Conservation Division

BEFORE: WILLIAM J. LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
GARY CARLSON, COMMISSIONER

February 24th, 1995

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on Friday, February 24th, 1995, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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February 24th, 1995
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CASE NO. 10,994

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* * *

WHEREUPON, the following proceedings were had at 9:00 a.m.:

CHAIRMAN LEMAY: Good morning, this is the Oil Conservation Division [*sic*], and we're continuing our hearing agenda from yesterday, and we shall now call Case Number 10,994.

MR. CARROLL: Application of Enserch Exploration, Inc., for the assignment of a special depth bracket oil allowable, Roosevelt County, New Mexico.

CHAIRMAN LEMAY: Appearances in the case?

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

We represent Enserch Exploration, Inc., and I have three witnesses.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

MR. KELLAHIN: Mr. Chairman, members of the Commission, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing today on behalf of Phillips Petroleum Company in opposition to the Applicant, and we have two witnesses to be sworn.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Would those about to give testimony stand, raise your right hand?

(Thereupon, the witnesses were sworn.)

CHAIRMAN LEMAY: Okay, let's start.

MR. CARR: I have a brief opening statement.

CHAIRMAN LEMAY: Mr. Carr?

MR. CARR: May it please the Commission, Enserch Exploration, Inc., is before you today seeking the adoption of a special depth bracket allowable of 500 barrels of oil per day for the South Peterson-Fusselman Pool in Roosevelt County. This pool was established in July of 1978 as a result of the discovery of oil in the Enserch Lambirth Number 1 well.

At the same time the pool was established, special pool rules were adopted on a temporary basis that were later made permanent, providing for 80-acre spacing.

Since that time, this pool has been developed basically by two operators, Enserch and Phillips. There is another operator in the pool, Bledsoe, but they are operating a well that isn't in the structural feature which is the subject of today's hearing.

These two operators have developed the pool on a checkerboard pattern. As we will show you, there is an active water drive in the field, and we now find ourselves at a point where there are approximately five wells that remain capable of producing from the South Peterson-Fusselman Pool.

This case is about the waste of oil. It's about how to maximize recovery of oil as we move to the last days of this reservoir's producing life.

Enserch will call Mr. George Faigle, a geologist. He will review for you the nature of the reservoir. He will show you that what we have here is a fractured reservoir with an active water drive. There is no oil-water contact in the reservoir, because the fracture system at this point in the reservoir's life is water-saturated.

As I mentioned a minute ago, there are only five wells still capable of producing. The Lambirth Number 1, the discovery well, was and remains the best well in the pool. And we will show you that it is the best well in the pool because of the quality of the rock from which it produces and also because it is structurally the highest well in the reservoir.

We will then call Ralph Telford, a petroleum engineer, and he will review the history of the Lambirth Number 1. He will show you that after years of reliable top-allowable production, the well in late 1993 watered out and Enserch was faced with what to do to try and return the well to producing status.

And they discovered an SPE paper that talked about the benefits that could be obtained from high-volume lift, increasing the rates of withdrawal in a reservoir of this nature. And this paper showed that if you would accelerate production you could pull water out of the fractures, and when you did that oil would flow from the matrix.

All the conditions in the paper fit the South Peterson-Fusselman Pool and the Lambirth Number 1 well, so Enserch attempted to employ this technology on the well. And we'll review with you what Enserch did: first rod pumps, then a submersible pump, then a larger submersible pump.

And we will show you that we achieved exactly what the SPE paper suggested we could achieve: a well that can produce over 500 barrels of oil a day with a reduced water cut.

The reason we're here is that if we are to continue to produce this well and obtain the benefits from high-volume lift, we have to have a higher allowable for the Lambirth Number 1.

If we don't get the higher allowable pursuant to directions from this Division, the well is overproduced and pursuant to your direction the well will have to be shut in. And if we do, we will show you that we may in fact lose the well.

And we can show you that if we are able to go forward, we should be able to produce approximately 456,000 barrels of oil that otherwise will be lost.

The case first came before the Division in June of last year, and Phillips appeared at that time in opposition to the Application, and the Application was denied.

Finding 10 of that order denying the Application stated that the Application was denied because at this time there is insufficient data available to assume that an increased allowable will prevent waste and protect correlative rights.

At that time the Examiner was correct. We put the well on pump in May, we came to hearing in June, and the presentation was based on analogies to other wells in the pool and basically limited data.

But since that time, we have nine months of additional data, and we can show you that HVL works in this reservoir, that it will prevent waste, that it will substantially increase the recovery of oil from this reservoir.

And then we will call Mark Burkett, a petroleum engineer, who will address the correlative rights aspects of this case, and he is going to show you that in fact there will be no adverse effect on any other operator in the pool, that correlative rights cannot be impaired.

And we will conclude by showing that if the Application is not granted, there is no correlative-rights issue, that almost 500,000 barrels of oil will be lost.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

This pool was developed based upon a farmout from Phillips Petroleum Company to Enserch, and the discovery well was drilled by Enserch back in 1978.

You'll see from the exhibits that there's an interesting pattern to the spacing units. They are 80-acre laydown spacing units, and it's checkerboarded.

As a result of the farmout, Phillips retained the alternative 80-acre tracts. And so when you look at the displays, you're going to see every other spacing unit, if you will, developed by one operator versus the other.

The reservoir rules were developed in 1978, and for some 17 years, now, this pool has been operated and depleted based upon an oil allowable of 267 barrels of oil a day.

There is a water component to the reservoir that's of significance to you. I have before me, and I will give you copies of, the order that Mr. Carr referred to. It was an Examiner case held in June of last year. And in November of 1994, then, on the third of November, the Division entered the order denying the Application of Enserch.

There were some fundamental issues of difference between the parties back in June. Those fundamental differences continue today. The additional information developed since the last hearing does not change the conclusions.

Despite the contentions of Mr. Carr, this is not a waste case; it is our evidence and our expert opinion from our witnesses' belief that this is strictly a correlative-rights case.

You will see when you look at the displays from our witnesses that the Enserch Lambirth Number 1 well does in fact enjoy a significant advantage over the closest well operated by Phillips.

The Phillips well is the Lambirth 2 A well. The Enserch well is the Enserch Lambirth 1 well. Both operators have used Lambirth in the naming of the wells. Those are the two wells that you will see, and we will talk about the most.

The advantage to Enserch is that they are 38 feet higher in their perforations in the top of the reservoir, and they have the opportunity to continue to produce their well so that it will drain the downstructure Phillips well.

And if you increase the oil allowable, you simply increase the opportunity for Enserch to take from Phillips Phillips' share of the remaining oil before Phillips has a chance to produce it.

It is our contention that after 17 years, we see no reason to change the rules. We are well aware of the SPE paper. We have studied that SPE paper in detail, and our witnesses come to different conclusions than Mr. Carr.

We believe this is a correlative-rights case because it's simply one operator utilizing a proposed increase in oil withdrawals to take advantage of the downstructure operator.

It will be our testimony that this is not a waste case, that the increased rates of oil production in the Enserch well don't result in increased ultimate pool oil recovery. The increased recoveries attributable to Enserch, our proof will show, are simply draining oil from us that we would otherwise produce. The dispute then is the dispute now. We believe none of the new information changes any of the results that Mr. Stogner entered when he decided this case back in November of 1994.

We believe at the conclusion of this hearing that we hope you will agree with us that the correlative rights of Phillips are impaired if you grant this Application, and we would ask that you affirm the Examiner order and deny the request of Enserch.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Mr. Carr, you may proceed.

MR. CARR: At this time, if it please the Commission, we would call Mr. George Faigle.

GEORGE FAIGLE,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?
A. George Faigle.
Q. Where do you reside?
A. Midland, Texas.
Q. By whom are you employed?
A. Enserch Exploration.
Q. And what is your current position with Enserch?
A. Development geologist.
Q. Mr. Faigle, have you previously testified before the Oil Conservation Commission?
A. Yes.
Q. At the time of that prior testimony, were your credentials as an expert in petroleum geology accepted and made a matter of record?
A. Yes.
Q. Are you familiar with the Application filed in this case on behalf of Enserch?
A. Yes.

Q. Are you familiar with the rules for the South Peterson-Fusselman Pool and the wells located therein?
A. Yes.
Q. Could you briefly summarize for the Commission what Enserch seeks with this Application?
A. Enserch seeks amendment of the special pool rules and regulations for the South Peterson-Fusselman Pool to provide for a special depth bracket allowable of 500 barrels of oil per day.
Q. Initially could you summarize for the Commission the current rules that govern development in this pool?
A. Eighty-acre spacing, designated well location requirements being within 150 feet of the center of the quarter quarter section.
Q. Now, those are the special pool rules; is that correct?
A. Yes.
Q. And then what are the other statewide rules that would come into play?
A. Okay, the statewide rules are depth bracket allowable of 267 barrels of oil per day.
Q. For an 80-acre tract?
A. For an 80-acre tract.
Q. And what is the gas-oil ratio?
A. 2000 to 1.

Q. And using these figures, what would the resulting casinghead gas allowable be for the pool?

A. 534 MCF per day.

Q. Let's go to Exhibit Number 1, and I'd ask you to identify that for the Commission.

A. Exhibit Number 1 is a small-scale orientation plat which shows the location of the South Peterson-Fusselman Pool as indicated by the green dot.

Q. And this is just -- generally shows where it is located in regard to other reservoirs in eastern New Mexico?

A. Yes.

Q. Let's go to Exhibit Number 2. Would you identify and review that?

A. Exhibit 2 is a large-scale area map showing the Fusselman producers in red dots and the pool operators, being Enserch, Phillips and Bledsoe.

Note that the Phillips 1 A is shut in at this time and that the Enserch Number 3 Lambirth Fusselman production is commingled with the Pennsylvanian production as of May of 1994. It also shows the completion dates of surrounding wells and the Enserch lease position.

Q. And the five wells in the center of the exhibit are basically the five wells that still do produce from the Fusselman in the area?

A. Yes, that's correct.

Q. And the arrow indicates the Lambirth Number 1?

A. Yes.

Q. Could you review the -- just generally, the characteristics of that well?

A. Okay.

Q. It is the best well in the pool, is it not, Mr. Faigle?

A. Yes, it's the highest well in the pool, and it's the best well in the pool.

Q. Okay.

A. It's indicated by the red arrow, as we stated previously.

Q. All right. Let's go to Exhibit Number 3. Will you identify that, please?

A. Okay, Exhibit Number 3 is a structure map on the lower paleozoic carbonate, which is the Fusselman in this area. It was prepared from well control.

It shows the five Fusselman wells left in this area. It also shows the Bledsoe well in Section 10; that's in the lower left-hand corner. It's also a Fusselman producer, which is interpreted to be on a separate structural closure.

The structural position of the producing wells in this pool shows the Number 1 Lambirth to be the structurally highest well in the pool.

Q. All right, let's now go to Exhibit Number 4. Would you identify that, please?

A. Exhibit 4 is a type log illustrating the Fusselman Pool. It was -- It is the log of the Number 1 Lambirth. It shows the area stratigraphic section being Pennsylvanian, on top of Fusselman, on top of granite, and it also shows the perforated interval in the Number 1 Lambirth.

Q. Could you generally describe for the Commission the characteristics of the Fusselman formation in this area?

A. Lithologywise, the Fusselman is dolomite, white to light gray through light tan, finely to coarsely crystalline to sucrosic. In the Number 1 Lambirth it was 178 feet thick, and the reservoir was encountered 60 feet into the Fusselman.

Porosities are in the range of 20 percent. The porosity is a bimodal system consisting of fractures and intercrystalline matrix porosity.

Permeabilities are in the range -- the 500-millidarcy range.

This is a water-drive reservoir. The trap is basically a structural accumulation of oil, formed at an angular unconformity where the Fusselman subcrops against the Penn.

Q. Now, Mr. Faigle, you prepared a cross-section of the wells in the pool?

A. Yes, sir.

Q. Let's go to Enserch Exhibit Number 5 and review that cross-section for the Commission.

A. Okay, Exhibit 5 is a structural cross-section showing the structural position of the Number 1 Lambirth and the three offsetting Phillips wells. It also shows the perforated interval in each well.

Q. Those perforations are indicated in green?

A. In the green color.

Q. And what does this tell you?

A. It -- The cross-section or the perforations?

Q. The cross- -- The perforations.

A. That they vary slightly from well to well. The reservoir is found in different structural positions in different wells.

Q. Structurally, the Lambirth Number 1 is the highest well in the pool, is it not?

A. Yes.

Q. Does the cross-section show an oil-water contact?

A. No, because the Fusselman pool is essentially watered out, an oil-water contact is irrelevant at this time.

Q. Let's look at Exhibit Number 6, please. Could you identify that?

A. This is a diagram of the high-volume lift concept and a geologic interpretation of how the high-volume lift theory applies to the Number 1 Lambirth.

It shows the dual-porosity system, fractures in the matrix, it shows the original oil-water contact, it shows that the oil in the fractures has been produced and replaced by water; the field has watered out.

It shows incremental oil in the matrix porosity, some of which can be covered by high-volume lift production methods, the details of which will be discussed in the engineering section.

Q. Basically, Mr. Faigle, what geologic conclusions can you reach from your study of this pool?

A. The reservoir is a dolomite, which has a heterogeneous bimodal porosity system consisting of both fractures and intercrystalline matrix porosity.

The pool is a structural accumulation of oil with the Number 1 Lambirth the highest well in the pool.

The main reservoir has watered out.

Q. And this geological interpretation is going to be used as a basis for the Enserch engineering presentation; is that correct?

A. Yes.

Q. Were Exhibits 1 through 6 prepared by you?

A. Yes.

MR. CARR: At this time we would move the admission of Enserch Exhibits 1 through 6.

CHAIRMAN LEMAY: Without objection, Exhibits 1 through 6 will be admitted into evidence.

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

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Faigle, sir, if you'll turn with me to your Exhibit Number 3.

Did you bring with you, Mr. Faigle, a copy of the Exhibit 3 that you introduced before Examiner Stogner back in June of 1994?

A. No.

Q. Let me show you, Mr. Faigle, what was introduced at that hearing and sponsored by you as Exhibit Number 3 and ask you if you recognize this exhibit.

A. Yes.

Q. Is that a true and accurate copy of the exhibit that you introduced before Examiner Stogner back on June 23 of 1994?

A. Yes.

Q. On your Exhibit 3 from the Examiner hearing, Mr. Faigle, you scribed a red line around some of the wells in the pool that would include the Lambirth 1 and the Lambirth 2 A. Do you remember doing that, sir?

A. Repeat that, please.

Q. Yes, sir. On Exhibit 3 from the Examiner hearing, you had scribed a red line on that exhibit. I'm looking at the one from the Examiner hearing. You scribed a red line around some of the wells, including your Lambirth 1 and the Phillips Lambirth 2 A, did you not do that, sir?

A. And several other wells.

Q. Yes, sir. You did that; is that not correct?

A. It essentially outlined the five producing wells -- it encircled the five producing wells we see on Exhibit 3, which is presented in this hearing.

Q. All right, sir. And your testimony at that time is, that circle represented the remaining productive acreage at that point in time in the reservoir, did it not?

A. No.

Q. On page 12 of that transcript, Mr. Faigle, did Mr. Carr ask you and did you not answer Mr. Carr, saying, "Now..."

MR. CARR: Let's --

MR. KELLAHIN: It's page 12, Mr. Carr.

MR. CARR: Let me give the witness a copy.

MR. KELLAHIN: It's page 12.

MR. CARR: What line are you at?

MR. KELLAHIN: I'm starting at line number 9, Mr. Faigle.

THE WITNESS: Okay.

Q. (By Mr. Kellahin) Are you with me?

A. Okay.

Q. It says, "QUESTION: Now, the area that you have indicated with the circle on this Exhibit, that's not the pool boundaries but just the acreage which you estimate now still productive in the reservoir?

"ANSWER: That outlines the are" -- I think that's a typo; it should say "area" -- "of the productive wells..." Right?

A. Yes, that's what it says.

Q. All right. Was that scribed area intended to represent the productive acreage left in the reservoir at that time?

A. No, it was put on there to outline, to run a circle around the producing wells.

Q. All right. The exhibit you've introduced today is substantially different than the Exhibit 3 from the June hearing, is it not?

A. It's different. I don't agree with "substantially".

Q. All right. Why have you changed your display from the one introduced in June?

A. Re-evaluation of the data.

Q. Have you changed the top marker point at which you've contoured the structure?

A. Yes.

Q. Okay. Exhibit 3 from the June hearing is on the top of the Fusselman, as you identified it back at that prior hearing, is it not?

A. That's correct.

Q. All right. On Exhibit 3 for today's hearing, what have you used as the top on which you have then contoured the structure?

A. The lower paleozoic carbonate.

Q. All right, let's go to the type log that you're introduced today and have you show us the difference.

A. Now your question, Mr. Kellahin, was --

Q. Yes, sir, you have changed the point at which you have drawn the structure map; am I understanding that correctly?

A. I have made some changes to the contoured horizon.

Q. Yes, sir. I want to look at the type log and find out where to find on the type log the points you've used as the marker point to construct the new structure map.

A. It's the line between the words "base of Pennsylvanian" and "lower paleozoic carbonate" --

Q. All right.

A. -- is the current contoured horizon.

Q. If we're looking at the structure map from the June hearing, where on this type log would we find that point?

A. I'll have to make an assumption on that. I don't recall exactly. I would assume it was around 7800 feet drilling depth.

Q. All right. What's the basis for changing the point at which you've drawn the structure?

A. To alleviate some of the confusion it caused.

Q. All right. When we look at the Exhibit 3 today, can you identify for us what in your opinion was the original oil-water contact in the reservoir at a minus subsea depth?

A. The original oil-water contact was in the vicinity of minus 3450 to minus 3440.

Q. All right, sir. Let me take a copy of your Exhibit 5 from today's hearing, which is the cross-section that you presented. I'm going to show you my copy, if I may. If I might lay this in front of you, Mr. Faigle. If you'll help me find --

A. 3450.

MR. KELLAHIN: If you'll help me find on my copy of your cross-section the point, minus 3450, that represents the original oil-water contact in the reservoir, I want to scribe a red line to show where that original oil-water contact was, all right?

All right, sir. Thank you, Mr. Faigle.

MR. KELLAHIN: Mr. Chairman, at my request Mr. Faigle has marked my copy of the log at the point with a pencil on each log where he has identified the original oil-water contact, and so that you'll be able to see that I'm going to draw a red line that connects those points so that there's a visual reference.

Q. (By Mr. Kellahin) When we look at the cross-section, my copy, I've put on the easel, just so that we could look at the same Exhibit at the same time, Mr. Faigle, when we're looking at that cross-section and find the Enserch Number 1 Lambirth well, the top perforation in the Enserch well is at a subsea depth of what, sir?

A. Minus 3380.

Q. And does that top perforation represent, in your opinion, the top of the original oil within the Fusselman reservoir?

A. It could be interpreted to mean that.

Q. So if we were to perforate higher in your well, we're not going to get any more oil production in the Fusselman?

A. I can't be sure enough to say that. There might be some minor amounts producible in the tighter parts of the reservoir.

Q. All right. When we go over to the Phillips 2 A Lambirth well, which is the first well on the left side of the cross-section, what is the top perforation in their well in a subsea depth?

A. Minus 3418.

Q. All right. The advantage in terms of that relationship is about 38 feet in preference to the Enserch well, is it not?

A. Correct.

Q. When we look at the cartoon, the Exhibit 6, the schematic illustration of -- that you're depicting, you have concluded that at this point in the depletion of the reservoir, that the fractures have watered out?

A. Yes.

Q. All right. With the original oil-water contact as we've described it on the cross-section, describe for us geologically how you believe that water to have moved so that now all the fractures are filled with water.

A. A water table will usually -- A bottom-drive water table will usually encroach from the bottom upward.

Q. Is it your opinion that this is a bottom-drive -- bottom water drive reservoir?

A. Yes, it is.

Q. All right, upon what do you base that opinion?

A. Literature.

Q. Do you have any field data with regards to this pool that supports that opinion?

A. This is more an engineering-type question, but I believe we do have some data that would indicate this.

Q. All right. You as a geologist don't see any geologic evidence to support whether or not it's a bottom water drive as opposed to an edge water drive?

A. I see some evidence, yes.

Q. As a geologist?

A. Yes.

Q. All right. If your concept of the bottom water drive is correct, then, would the water uniformly move vertically in the reservoir as the wells deplete the reservoir?

A. It would move -- generally -- It's not going to come up on a perfectly flat, horizontal plane. The water tables don't encroach that way. It would come up erratically. Not extremely erratically, but it's not going to come up as a horizontal plane, a flat, horizontal plane; it's going to come up gradually.

Q. All right. As that bottom water drive encroaches vertically into the oil column, if you will, what was the first well to experience increased water cuts that could be attributable to the migration vertically of that water?

A. Of the four wells on the cross-section?

Q. Yes, sir.

A. I would assume it would be the lowest structural position. The well with the lowest structural position would have the water cut first.

Q. All right. Describe for me your concept of the reservoir between this fracture system and what you've described as matrix oil.

And perhaps the Exhibit 6 is the display to look at. You have illustrated the reservoir to be a combination fracture and matrix porosity?

A. Yes.

Q. A dual-porosity system, if you will?

A. Bimodal porosity system.

Q. All right. Tell us why you have that belief.

A. Performance of the wells, literature, published literature.

Q. As the water drive moves up, it encroaches into the upper portion of the reservoir that originally had oil, it is your conclusion that that water has filled up the fracture system; is that not what this shows?

A. Yes.

Q. Okay. And at this point in the life of the reservoir, where, then, is the remaining oil left to be produced?

A. There may be some left in the fractures, small amounts that we're talking about, one percent or in that neighborhood. The oil remaining in the reservoir, we believe, is in the matrix porosity.

Q. Describe for us why you have that belief.

A. Because the production characteristics of the wells would indicate that the oil would be produced from the fractures first since they have the greatest permeability, and they would water out first.

Q. Mr. Carr mentioned that there were still five wells left in the pool that continue to produce. You've shown four on the cross-section. Where is the fifth?

And perhaps we could look at a locator map. Exhibit 3 serves that purpose, I believe, if you'll look at Exhibit 3.

A. The Fusselman producer not on the cross-section is the Enserch Number 3 Lambirth.

Q. All right, it's the northeast offset to the well with the red arrow?

A. Yes.

Q. Why has that well been excluded from the cross-section?

A. It was my understanding of the problem, was between the Enserch Number 1 Lambirth and the offsetting Phillips wells.

Q. What is the status of the Enserch Lambirth 3 well, the well that's excluded from the cross-section?

A. The Number 3 is producing commingled from the Pennsylvanian and the Fusselman.

Q. Is it still producing oil, then, from the Fusselman?

A. We have to assume so. Being commingled, there's no way I can qualify or disqualify which zone is producing the oil.

Q. When was that well commingled, Mr. Faigle, approximately?

A. May, 1994.

Q. At the time it was commingled, was it open in the Fusselman?

A. No, it was a Pennsylvanian producer that was recompleted commingled to Fusselman and the Pennsylvanian.

Q. All right. So you had Pennsylvanian gas production or oil?

A. Oil.

Q. Pennsylvanian oil production in the well, and then you went up and added the Fusselman?

A. We went down and --

Q. I'm sorry.

Q. -- recompleted in the Fusselman.

Q. All right.

A. The well was originally a Fusselman producer, low oil volumes, high water volumes, which was produced for a very short period of time in the Fusselman and then recompleted to the Penn.

Q. At the time that the Fusselman was originally abandoned in that well, what kind of oil-water rate did you have?

A. I don't know.

Q. All right. Do you recall approximately when that took place?

A. No.

Q. At this point is it fair to assume that there's little if any contribution from the Fusselman in that wellbore? That's a --

A. No.

Q. We don't know?

A. No, I don't think it's fair to assume that there's little or no contribution from the Fusselman in that wellbore.

Q. At this point there's no way to retrieve the data from that well to determine whether or not there's any oil contribution from the Fusselman?

A. State that again, please.

Q. Because it's been commingled, there is no way to currently know what oil contribution is being made from the Fusselman in that well?

A. We know what it was capable of before the Fusselman was abandoned the first time, and we assume that when we went back there, we were in the neighborhood of those volumes.

Q. And what rate was that again, sir?

A. I do not know.

Q. All right. Can you quantify or define for me, Mr. Faigle, how you're using the term "watered out"?

A. When a well reaches water cuts of approximately 95 percent and also it's becoming marginally economic, it's costing more to dispose of water and lift than we can make a profit from the oil that the well produces, it's essentially -- it's economically watered out.

Q. I'm not sure I understood the answer. You gave me two criteria. A water cut of 95 percent?

A. It varies. It depends on the volumes you're lifting.

Q. All right. Separate that for a moment. You also gave me an economic criterion.

A. Yes.

Q. You could have an economic criterion that made a well unprofitable --

A. Yes.

Q. -- at less than 95-percent water cut, could you not?

A. Sure.

Q. All right. Which of those two criteria are the determining factor in your definition of "watered out"?

A. I would use them both.

Q. At what time in the productive life of the reservoir did the fracture system, in you opinion, become watered out?

A. Which well? It happened --

Q. Well, all wells, now, in your opinion, have watered out in the fracture system?

A. The fracture system has watered out.

Q. In all wells?

A. In all wells.

Q. At what point did that occur in your Enserch Lambirth 1 well?

A. I don't know. The engineering section may be able to help you with that answer.

Q. All right. Would you know the point in time where the fracture system in any of these wells watered out, by your definition?

A. It would depend on operating costs and things that -- on an individual well basis you'd have to look at it.

Q. Can you express an opinion as to when any of these wells watered out in the fracture system?

A. A particular date, no, that would have to be an engineering evaluation considering economics and volumes and...

Q. Was it your opinion before Examiner Stogner that the increasing oil allowable that you've requested was not going to be an advantage of Enserch over Phillips because you believe the rising oil-water contact was going to affect all wells approximately equally, because all of them had a similar relationship as to their bottom perforations?

A. State that again, please.

Q. Yes, sir. If you'll look at the transcript, maybe that's how to do this. Look at Exhibit -- the transcript, and if you'll turn to page 13 with me, if you'll look at line 18.

A. Page what? Thirteen?

Q. Yes, sir, line 18. Mr. Carr is asking you, "So in the Enserch well, the well that you're primarily concerned about, and the immediate offsetting Phillips well to the north, the bottom of the perforated interval is identical?

"ANSWER: Correct. Now, this -- Therefore a rising oil-water contact would affect both wells equally. There would be no advantage to either well."

Do you see that?

A. Yes.

Q. All right. Was it not your conclusion geologically at the Examiner hearing that as a result of the bottom water drive and the fact that the Enserch Number 1 well and the Phillips 2 A well had bottom perforations that were approximately at correlative intervals in the reservoir, that you could increase the oil allowable, and you would have no advantage?

A. I don't understand what you're --

Q. What part of my question do you not understand, sir?

A. Well, could you break it down into pieces? Maybe I can handle it better that way. I seem to be getting a complex question, and I don't know how to answer it.

Q. All right. You have reached the opinion that this is a bottom water drive reservoir, right?

A. Yes.

Q. All right. When you look at the perforations in the bottom of the Lambirth well for Phillips, the 1, if you look at the cross-section --

A. Yes.

Q. -- do you see that?

A. Yes.

Q. All right. That bottom perforation is in what relationship to the Enserch Number 1 well?

A. They have similar subsea depths at the bottom of the perforations in each of those two wells.

Q. All right. Because that is so, and because you concluded that this was a bottom water drive, you've also concluded, did you not, sir, that there would be no advantage to Enserch by increasing the oil rate, because the increased rate would simply affect both wells equally as the water moved vertically?

A. We were beyond that point in the -- where to position -- The reservoir was already watered out at that time. So at that time there would be no advantage, it was too late for an advantage. We were speaking historically about rising oil-water contacts. At the time of the hearing, the oil-water contact was essentially at the top of the reservoir by then, or very close to it.

Q. Okay.

A. The advantages you're looking for may have been historical. They weren't current.

Q. All right. Do you see any remaining oil column, then, in the matrix above the original oil-water contact?

A. Yes.

Q. Can you determine where that point is in the matrix?

A. I'll have to make an assumption that there's matrix oil available everywhere above the original oil-water contact if you can get it out.

Q. All right. Does not, then, Enserch continue to enjoy an advantage of some 38 feet in the perforations between you and Phillips as you compete for the remaining oil in the matrix?

A. There's no doubt about it, we have the highest structural well in the best reservoir, I can't dispute that.

MR. KELLAHIN: All right, sir.

Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Thank you.

MR. CARR: Mr. Chairman, I'd like to --

CHAIRMAN LEMAY: I'm sorry.

MR. CARR: -- and I'll be brief.

CHAIRMAN LEMAY: That's fine.

REDIRECT EXAMINATION

BY MR. CARR:

Q. Mr. Faigle, at the Examiner hearing there was some confusion about the zone or the interval that you used for constructing the structure map of this reservoir map; is that not true?

A. Yes.

Q. And so to correct that what you did was, you went and picked a marker that is the base of the Penn in a clearly definable interval; is that not correct?

A. Correct.

Q. Isn't that what caused the difference between the structure map that was offered in June and the structure map that is offered now?

A. Yes, it did.

Q. And by drawing a red line at the original oil-water contact in this reservoir, hasn't Mr. Kellahin in essence just taken your structure map, and it is a more refined example of what the schematic is designed to show?

A. Correct.

MR. CARR: That's all I have.

CHAIRMAN LEMAY: Thank you.

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. You said that it actually fractured the perm 500 millidarcies. Did you measure that, or is that an estimate?

A. That's a measured permeability from a well performance test on the Number 1 Lambirth.

Q. So this is, I think, perhaps more an engineering question, but the fractures were identified from the same test?

A. We assumed, I believe, that there were fractures. They're about the only thing that could give us a permeability of that magnitude after looking at the porosity on the logs.

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

CHAIRMAN LEMAY: Commissioner Carlson?

COMMISSIONER CARLSON: No questions.

CHAIRMAN LEMAY: I have no questions. Thank you.

MR. CARR: May it please the Commission, at this time we would call Mr. Ralph Telford.

RALPH B. TELFORD,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Ralph Telford.

Q. Where do you reside?

A. Midland, Texas.

Q. By whom are you employed and in what capacity?
A. Enserch Exploration as a petroleum engineer.
Q. Have you previously testified before the Commission?
A. Yes, I have.
Q. At the time of that prior testimony, were your credentials as a petroleum engineer accepted and made a matter of record?
A. Yes, they were.
Q. Does the geographic area of your responsibility with Enserch include the Southeast Peterson-Fusselman Pool area?
A. Yes, it does.
Q. Are you familiar with the wells completed and producing from that pool?
A. Yes, I am.
Q. Are you familiar with the Application filed in this case on behalf of Enserch?
A. Yes.
MR. CARR: Are the witness's qualifications acceptable?
CHAIRMAN LEMAY: They're acceptable.
Q. (By Mr. Carr) Mr. Telford, could you review for the Commission what it is Enserch is asking the Commission to do in this matter?

A. We're looking for an assignment of a special depth bracket allowable for the South Peterson-Fusselman Pool of 500 barrels of oil per day to replace the current depth bracket allowable for said pool of 267 barrels of oil per day.

We want an assignment retroactive to June 1st, 1994, which is the date which Enserch's Application was filed. And if we're not approved, the well is overproduced and we'll have to shut it in.

Q. The reason for the retroactive request, that June 1st is the first day of the first month following the day the Application was filed?

A. Yes.

Q. Initially, Mr. Telford, could you just summarize the existing rules for the pool?

A. Pursuant to Order R-5771 as amended by Order 5771-A, special rules and regulations were adopted for this pool which provided for 80-acre spacing and designated well location requirements.

Statewide rules are 80-acre, depth bracket allowable of 267 barrels of oil per day, a 2000-to-1 GOR which resulted in a 534-MCF-per-day casinghead gas allowable.

Q. All right. Now, those were the rules that were in place in May of last year?

A. Yes.

Q. At that time you were experiencing problems with the Lambirth Number 1 in terms of maintaining its production levels?

A. Yes.

Q. And an Application was then filed with the Oil Conservation Division?

A. Yes.

Q. Could you refer to Exhibit Number 7 and then just very briefly review for the Commission the history of this particular case?

A. Okay, in July 17th, 1978, the pool was established and temporary pool rules were adopted providing for 80-acre spacing and proration units. In August of 1979 the pool rules were adopted on a permanent basis.

In May of 1994 we installed a submersible pump on the Lambirth 1. And May 9th of 1994, a special allowable authorized for the Oil Conservation in the Hobbs District, we received a letter from them.

And May 17th, 1994, Enserch filed Application for a special depth bracket allowable.

On June 23rd, 1994, Enserch appeared before the Commission, like we are today, to get the rules made permanent. We had a continuance till July 21st.

And on November 3rd the -- we received the Order

R-5771-B denying the Application of Enserch.

On November 8th, Enserch filed for the Application, for hearing *de novo*.

January 12th, the Oil Conservation Commission hearing was continued, at the request of Enserch. Phillips advised the Commission it had no objection to the continuance.

And February 24th, today, we are here to settle this whole thing.

Q. Now, Mr. Telford, identify what's been marked as Enserch Exhibit 8, please.

A. It is the Oil Conservation Division Order R-5771-B, dated November 3rd, 1994, which denied Enserch's Application.

Q. Now, this is the Examiner Order, and the Order in its findings sets forth the presentation of both the parties; is that correct?

A. That is correct.

Q. Could you go to Finding Number 10 on page 4 and just read that into the record, please?

A. It says, "At this time there is insufficient data available to assure that increased oil allowable for the South Peterson-Fusselman Pool will not result in the impairment of other operators' and mineral-interests' correlative rights in the pool and would not result in the prevention of waste."

Q. If we look at the case history, Exhibit Number 7, I believe you testified that you started experiencing the increased production rate from the Lambirth Number 1 in May?

A. That is correct.

Q. And it was on May the 9th that you approached the Oil Conservation Division concerning this matter?

A. Yes.

Q. And then the matter came for hearing on June the 23rd?

A. That is correct.

Q. It was on June the 23rd, was it not, that the actual evidence was presented in this matter?

A. Yes.

Q. So at that time you had less than two months' information on the well?f

A. That is correct, and we were also experiencing mechanical problems with the well at the time.

Q. At this point in time, has additional information been obtained that addresses the concerns expressed by Mr. Stogner in the Examiner Order?

A. Yes.

Q. Before we get into the actual information on the SPE paper and on the well performance, could you review what it is exactly you're requesting and why that request has to be made?

A. We're looking to increase the ultimate recoveries from the Lambirth Number 1. To do that, we must increase allowables from the pool.

The well currently produces in excess of the allowable, and special allowable will improve economics and increase this well's ultimate recovery. And this will also will not impair the rights of any other operator in the pool.

Q. Now, Mr. Burkett is going to be called to review that last point --

A. The correlative rights, yes.

Q. -- correlative rights?

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

A. This is SPE paper 7463. This paper was written in 1978 by Amoco, and basically the paper sets out a theory that we find applicable to the Lambirth Number 1.

The paper has empirical data from 55 wells. It shows an average increase of reserves of 350,000 barrels of oil. The parameters are applicable to these type of wells. The best candidates are in the Devonian reservoir. The reservoir is heterogeneous and has a water drive, and the wells are producing with less than a 95-percent water cut and greater than a 70-percent water cut.

Q. Now, do all of those parameters fit the South Peterson-Fusselman Pool and the Lambirth Number 1?

A. Yes, they do.

Q. Were you the individual that came across this SPE paper?

A. Yes.

Q. And when you saw that paper, were you the one who concluded that perhaps this type of high-volume lift would be something that could be tried on the Lambirth Number 1?

A. Yes.

Q. All right. Let's go back to Exhibit Number 6. It's up on the easel above the cross-section.

Basically, using this, just summarize what your understanding of the characteristics of this reservoir have to be.

A. Basically, what we have is a dual-porosity reservoir. You have the matrix and you have the fractures. And currently the fracture system is watered out and the remaining oil is in the matrix.

Q. Is that the kind of reservoir that was the subject of this SPE paper?

A. Yes, it is.

Q. All right, let's look at the Lambirth Number 1 well, and I would direct your attention to Enserch Exhibit

Number 10, the production history. Could you review that for the Commission?

A. Yes, the Lambirth 1 was the discovery well for the pool. Production started in 1978.

You'll notice the green curve is oil production, the red curve is gas production, the yellow curve is gas-oil ratio, the dark blue curve is water production, and the light blue curve is water cut.

You'll notice the well produced relatively flat till 1986 when the well started making water. The well was then pinched back to curtail this water production. This pinching back was continued until 1993 when the well essentially watered out and died.

Then a rod pump was installed, production increased to 60 barrels of oil per day and water cuts were in the 80- to 88-percent range.

In May of 1994 a submersible pump was installed.

Next, we need to go to exhibit --

Q. If we look at the exhibit, the gas-oil ratio is basically flat, is it not?

A. Flat, which is indicative of a water drive reservoir.

Q. And this is the -- not only the discovery well, but has been a top-allowable in the well --

A. Yes.

Q. -- well in the field?

A. It is the best well in the field.

Q. All right. Let's go now to Enserch Exhibit Number 11. Identify this, please.

A. Okay, what we have here is daily production for the Lambirth 1. It starts in December of 1993.

The dark green curve is oil production, the dark blue curve is water cut.

If you'll notice, in December until April the oil production was relatively flat, slightly declining. It's 60 barrels a day.

In May we put our first submersible in the well, denoted by the red line. Production then increased from 60 barrels a day to between 200 and 300 barrels a day. Also, if you'll notice, the water cut went from about 86 percent to 90 percent.

Later on, in August, we installed a larger submersible as denoted by the next red line. Production then increased to over 500 barrels of oil per day and water cut decreased from 90 percent to a low of 84 percent. And that's climbed to its current rate of between 86 and 87 percent.

Q. All right, Mr. Telford, when we look at Exhibit Number 10, the production history on the Lambirth Number 1, we have a well that basically fits the criteria in the SPE paper?

A. That is correct.

Q. And we've already established we have a reservoir that meets that criteria?

A. Uh-huh.

Q. Now, if we go to Exhibit Number 11, we can see what happened as you attempted to employ these high-volume lift techniques to the reservoir.

What does this production curve, Exhibit Number 11, tell you about the success of high-volume lift in this reservoir?

A. Okay, what I've done, if you'll notice the light dashed pink curve, that is a production decline shot for the rod pump. It also shows remaining reserves of 31,000 barrels of oil.

Next up, I've shot a decline from the smaller submersible. It showed a remaining reserves of 160,000 barrels of oil.

And finally, the dashed green curve shows remaining reserves of 487,000 barrels.

So incremental reserves over the rod pump is 456,000 barrels and 327,000 barrels over using the small submersible. And this is oil that would not be recovered by any other well in the pool unless we keep the large submersible in the well.

Q. So this Exhibit Number 11 shows that when you put the submersible pumps on the well, in fact you got the response that you were anticipating in accordance with the SPE paper?

A. Yes, we -- It shows larger recoveries and also the decreased water cuts.

Q. And basically what it shows when you then take the new production curve and plot it out, that you will recover ultimately almost 500,000 barrels of oil more with the large submersible pump in the well than you would have been able to with simply the rod pump?

A. That is correct.

Q. Now, Enserch obviously is recovering more oil from the Lambirth Number 1 than any other well in the pool?

A. That is correct.

Q. And that's a result of these recovery techniques?

A. Yes, that's also due to better structure and better quality rock and more oil underneath our tract.

Q. In your opinion, is it possible that this high-volume lift technique could be applied to other wells in the pool?

A. Yes.

Q. In fact, has it been?

A. Yes, it has.

Q. In what wells?

A. The Lambirth 1 A and the 2 A.

Q. Have the -- comparable results been obtained in those other wells?

A. Not as good as the Lambirth 1 A.

Q. Do those other wells have comparable structure or rock quality when you compare them to the Lambirth Number 1?

A. No, they do not.

Q. All right. Let's go to what has been marked Enserch Exhibit Number 12. Could you identify and review that, please?

A. Basically what we have here is a list of wells that Enserch operates that have been lost to casing failures in the South Peterson area.

If you'll notice, there's twelve wells in the list. This represents 41 percent of the wells that we operate in the area.

Due to losing these wells we've lost reserves of 460,000 barrels of oil and 478 million cubic feet of gas.

Q. The Lambirth Number 8 has been lost since the hearing last June?

A. That is correct. That was one of the candidates that we were looking to apply the high-volume lift to.

Q. And when did that casing collapse occur, casing failure occur?

A. September of 1994.

Q. If we look at Exhibit Number 12, this simply shows that if you lose your well, you're unable to produce your reserves?

A. That is correct.

Q. If we look and relate that back to Exhibit Number 11, what that shows is that by employing high-volume lift you recover additional reserves that in fact are not going to be achieved but left in the ground?

A. That is correct.

Q. If you're able to employ high-volume lift in a timely fashion, you're going to get the benefit not only of the technique, but you're hopefully going to have a well that will enable you to recover these reserves?

A. Yes. I'd also like to point out that the Lambirth Number 1 is the oldest well in the pool.

Q. Mr. Telford, in your opinion will approval of this Application and the increase in the allowable permit Enserch to produce the Lambirth Number 1 in a fashion that will ultimately result in the prevention of waste of oil?

A. That is correct, yes.

Q. Will you be calling another witness, Mr. Burkett, to review the correlative-rights aspects of this Application?

A. Yes.

Q. Were Exhibits 7 through 12 prepared by you or compiled at your direction?

A. Yes, they were.

MR. CARR: At this time, may it please the Commission, we move the admission of Enserch Exhibits 7 through 12.

CHAIRMAN LEMAY: Without objection, Exhibits 7 through 12 will be admitted into the record.

MR. CARR: That concludes my direct examination of this witness.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Telford, if you'll find Exhibit 10 for me, perhaps we can use that to illustrate my questions for you, sir.

In terms of your chronology, when did you first put in the first pump that had the ability to produce sufficient fluids from your well so that you had the opportunity to produce oil in excess of the daily oil allowable of 267 barrels?

A. That would be May.

Q. That's the May of 1994 --

A. That's the small submersible.

Q. The highest rate of oil productivity on a daily basis that you were able to achieve with that submersible was what, sir?

A. That was slightly over 300, I believe. If I can look --

Q. I believe your --

A. About 350.

Q. All right. Somewhere in the 330 to 350 range, I believe, is what we talked about last June.

A. That is correct. Since then we've installed the larger submersible.

Q. All right. From the point of time that you exceeded the allowable, the 267, up until the date of the hearing, there's a reference here to an authorization by the Hobbs OCD --

A. Yes.

Q. -- to conduct a test, if you will --

A. That is correct.

Q. -- and exceed the oil allowable. All right? Is that not correct?

A. That is correct.

Q. And you introduced a letter from Mr. Sexton back in June describing for you the terms and conditions for that test; is that not correct?

A. That is correct.

Q. I show you a copy of what was introduced as Enserch Exhibit 11 to that Examiner hearing.

What were the conditions imposed upon Enserch for producing in excess of the daily oil allowable?

A. That we file for a hearing within 20 days.

Q. All right, sir, and you did that?

A. Yes, we did.

Q. And the last paragraph of that letter says that after the order is entered for that hearing, what then will happen?

A. The well will have to be curtailed and the overage made up.

Q. All right. From the hearing, July -- I'm sorry, June 23rd, that was our evidentiary hearing? --

A. Yes.

Q. -- to the date of the Order, November 3rd of 1994, what did you do in terms of producing that well?

A. We installed the larger submersible pump and gathered more data.

Q. Okay, the larger submersible pump was installed approximately when, sir?

A. In August.

Q. Do you have a date in August?

A. The exact date? Not with me.

Q. All right, sir. In August of 1994, you went to a larger submersible with what result?

A. With what result? Increased oil recoveries and decreased water cut.

Q. Give us a general range of the oil rate on a daily basis that you were producing.

A. Close to 600 barrels of oil a day.

Q. All right. How long were you able to sustain producing at 600 barrels of oil a day?

A. Not very long.

Q. All right. You have production records on a daily basis --

A. Yes.

Q. -- that would show us exactly how this was done?

A. Exhibit 11 shows that.

Q. We can pull it off of Exhibit 11?

A. Yes.

Q. All right. On November 3rd, then, what then did you do with the well? After you got the Examiner order? I assume you got it reasonably at some period of time after November the 3rd.

A. We received it, I believe, on the 8th.

Q. All right. What then did you do?

A. We filed for a hearing *de novo*.

Q. All right. What did you do in terms of producing the well?

A. We kept producing the well.

Q. At what rate, sir?

A. At its current rate, 500 barrels a day.

Q. Okay. Did you go back to Mr. Sexton and ask for additional authority from him to produce in excess of what the Examiner had required you to do as a result of the November Order?

A. No, we did not. We assumed that since the case was still pending we could still produce the well.

Q. Is there anything in Mr. Sexton's letter that tells you you can do that?

A. No, there's not. But we have every intention of shutting the well in if we lose today.

Q. From November 8th to the current period, can you tell us what -- Let me ask you a different way.

What as of today is the current total overproduction of oil on the well?

A. As of November, it's approximately three months' worth of production. We'd have to shut in the well for three months.

Q. As of November --

A. As of November 1st, from November 1st to now, three months' production.

Q. Can you -- I don't know if you have it with you now, but you could calculate for us --

A. Actually, I may have it with me right here.
Q. All right, sir, let's get an actual number.
A. Actually, I've got it over there. Can I get it over here?
Q. Yes, sir.
A. The actual number as of November 1st through January is 25,081 barrels.
Q. From November 1st to when, sir?
A. Through January.
Q. Through January of 1995?
A. Through January of 1995.
Q. All right. Prior to November 1st, what is the overproduction?
A. I don't have those numbers handy.
Q. So the 25,000 is not a cumulative total --
A. No, it is not.
Q. -- of overproduction?
You keep production records on a daily basis, though, so should the Commission require it, you can tell the Commission exactly how much total overproduction is attributable to this well at any given point in time?
A. That is correct, that will be no problem.
Q. When we look at the SPE paper, the criteria, if you will, for having an opportunity to achieve increased oil rate with a high-volume lift system within the

parameters of that paper was a water cut between 70 percent and approximately 95 percent, if I remember the paper correctly?

A. That is correct.

Q. All right. Did I hear you correctly in response to Mr. Carr that that technique would have or could have been available to any of the wells in this South Peterson-Fusselman Pool if they were within that range?

A. That is correct, if they were within that range and they had the correct reservoir characteristics.

Q. All right. Does the paper describe any additional criteria in terms of reservoir characteristics?

A. Just a heterogeneous reservoir, preferably Devonian.

Q. Does it give you any preference or criteria to structural position?

A. I do not believe so, no.

Q. Does the paper qualify or alert the reader to the issue of premature water breakthrough?

A. Yes, it does.

Q. And what does it say about that issue?

A. Well, let me read it to you.

Q. All right.

A. It says, if you'll look on page 4 of the paper, "Concern over premature water breakthrough and reduced ultimate recovery from application of high-volume lift is unsubstantiated in most heterogeneous, west Texas carbonate, oil-wet, natural waterdrive reservoirs."

Q. Did the paper discuss or attempt to study whether or not the application of this technique would result in increased ultimate recovery for the pool?

A. No, it did not.

Q. It was talking about the opportunity for an individual well to increase its ultimate recovery?

A. Yes, but this could be applied to other wells, not just one well.

Q. I understand, but the paper was making no argument in terms of total reservoir recoveries in a waste context?

A. No, it did not.

MR. KELLAHIN: All right. Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Thank you.

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Is the well pumped off now?

A. No, sir, it is not. The fluid level is 1320 feet from the surface. I wish we could pump it off.

Q. So the other wells are still flowing, I take it, that are out there?

A. They're on submersible as well. Well, the A 2 is on submersible; our Number 3 is on rod pump.

Q. So they're all on artificial lift?

A. Yes.

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

CHAIRMAN LEMAY: Commissioner Carlson?

COMMISSIONER CARLSON: No questions.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. One question I have here on your Exhibit Number 11. That's the --

A. Daily production plot?

Q. Yeah, that's --

A. Okay.

Q. -- the detailed one. Was that well shut in, it looked like, through the month of April, 1994?

A. Yes, it was. We were waiting on electricity.

Q. But when you brought it back on, there was no problem bringing it back on after having it shut in that period of time?

A. No, there was not.

CHAIRMAN LEMAY: Thank you, that's all I have.

Do you want to take a break now, or -- Do you have one more witness?

MR. CARR: I have one more witness.

CHAIRMAN LEMAY: Okay, let's go with him.

MR. CARR: All right. At this time we would call Mr. Mark Burkett.

MARK BURKETT,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Mark Burkett.

Q. Where do you reside?

A. I reside in Midland, Texas.

Q. By whom are you employed?

A. Enserch Exploration.

Q. And what is your current position with Enserch?

A. I am the district petroleum engineer.

Q. Mr. Burkett, have you previously testified before this Commission?

A. Yes, sir, I have.

Q. At the time of that prior testimony, were your credentials as a petroleum engineer accepted and made a matter of record?

A. Yes, they were.

Q. Are you familiar with the Application filed in this case on behalf of Enserch?

A. Yes, sir.

Q. And are you familiar with the rules for the South Peterson-Fusselman Pool and the wells located therein?

A. Yes, sir.

Q. I'd like to direct your attention to what has been marked as Enserch Exhibit Number 13. Would you identify that and then review the information on this exhibit for the Commission?

A. Okay, Exhibit 13 is a -- as Mr. Telford testified earlier, this is a pressure profile, or a calculated pressure profile, of the pressure as a function of distance away from the wellbore for the Lambirth Number 1.

As you can see on the X axis, we have a distance from wellbore. It goes from zero to 1300 feet.

On the Y axis we have pressure, a wellbore pressure, from 2300 to 2550.

The green line is the static reservoir pressure that was determined from a pressure buildup test. The last pressure buildup test we conducted on the Lambirth Number 1 was 2518 p.s.i.

Our last fluid level that Mr. Telford referred to, 1320 feet, calculates to roughly a wellbore flowing pressure of 2318 pounds, which would be the intercept of the Y axis with the blue curve. The blue curve would represent pressure as you move away from the wellbore.

Now, this is a very simplified diagram; there were a lot of assumptions built into it. It's based on a very simple engineering calculation, Darcy's law. It assumes steady-state flow, it assumes an impotent-acting reservoir, only one well in the reservoir.

The KH or capacity was adjusted to take into account water and to take into account the actual data that we're seeing today, based on the fluid level. It assumes constant permeability and no skin.

This is a real basic model, but what it's showing is that most of the drawdown occurs in the first 150 feet.

It's also showing that we're only drawing down the wellbore 200 pounds, so we're just barely drawing on this reservoir. It's saying that we're unable to draw down the reservoir, and this is with the current 500-barrel-per-day production. So this is the current conditions, and it's basically saying that we're unable to draw down this reservoir even with the largest pump possible.

It's also showing it's a very prolific well, an extremely prolific well.

One other thing to point out is, as we get to the lease line, it's denoted by the dark line at about 660 feet. We see a pressure drawdown of about 31 p.s.i. at the lease line.

Q. All right, Mr. Burkett, let's take now this exhibit, put it aside and go to Exhibit Number 14.

Could you explain what you've done, how you've constructed Exhibit Number 14 and its relationship to the previous exhibit?

A. Okay, Exhibit 14 is really an extension of Exhibit 13. Again, you can see the blue line. On the left side of the page is the Lambirth Number 1. On the right side of the page would be the Lambirth A 2.

Again, the X axis is the distance from the Lambirth Number 1 well, the Enserch Lambirth Number 1.

The Y axis represents pressure and goes from 1700 pounds to 2600 pounds.

The lease line is shown at about 660 feet, so you can see that it's equidistant.

Again, the same assumptions apply here: steady-state flow, it's an impotent-acting reservoir. These are based on single wells, only one well in the reservoir. And that's a shortcoming of this exhibit, but it's done to simplify the problem; we could have a real complicated model here. We're just trying to simplify.

It assumes that the permeability is constant per well, no skin. And it's Darcy's law, the most basic reservoir engineering calculations.

What it's showing, it's showing based on the fluid level provided by Phillips, according to Phillips they had shot a fluid level to their well on June 21st 1995 [*sic*] of 1830 feet from the surface, and we calculated a bottomhole pressure of 1500 -- I'm sorry, of 2144 p.s.i., based on 1579 barrels of fluid withdrawn.

We matched the permeability with those parameters, and with the latest data we have, using 3263 barrels of withdrawal, we calculated a bottomhole pressure of 1743 p.s.i., which would be the intercept to the right corner of the diagram.

So what this represents is Enserch's pressure drawdown versus Phillips' pressure drawdown. It's showing that Phillips is able to draw down the reservoir 773 p.s.i. while Enserch is only able to draw their well down 200 p.s.i.

There are some shortcomings with the exhibit, based on the assumptions. But what it's showing is that -- It's showing a no-flow boundary way over on Enserch's property. In fact, it's occurring at around a point of 165 feet from Enserch's well. And a no-flow boundary would be if there were a drop of oil sitting at this distance, 165 feet from Enserch's well, it would not know whether to go to Enserch's well or to Phillips' well.

What this exhibit shows is that Phillips is draining Enserch's acreage, and it also shows that they have an advantage of a drawdown practically four times greater than what Enserch is enjoying.

Q. Mr. Burkett, what you've done is, you've taken the information on Exhibit 13 and added the Lambirth Number 2 A, the Phillips well, to the exhibit?

A. Yes, sir.

Q. What you have been able to show here is that within the limits of the information used, that in fact there's a four times greater drawdown by the Phillips well in the reservoir than what you've been able to achieve?

A. Yes, sir.

Q. And the information that you have on this exhibit is what -- the kind of drawdown you're able to achieve using the existing large submersible pump and under existing well conditions?

A. That is correct.

Q. Now, if you model this reservoir, you could obtain a more refined information or data on exactly what's happening; is that not right?

A. That is correct. And we've played with different parameters, we've adjusted the parameters, but the bottom line is, the character of the curves are still the same. And regardless of what we vary, in every case it reverts back to the no-flow boundary being way over on Enserch's property.

Q. In other words, the data may change, but in your opinion the conclusions would not?

A. That is correct, the conclusions will still be the same, that Phillips has an advantage over Enserch, even with our higher withdrawal rates.

Q. What conclusions have you reached, based on your review of this reservoir, concerning the impact of granting this Application on the correlative rights of interest owners in the pool?

A. Correlative rights will not be damaged by granting the special allowable. What we see is that Phillips is enjoying a four-times greater drawdown. They're drawing on a reservoir four times greater than Enserch is capable of drawing on it, and that we see a net drainage in the direction of Phillips.

Q. Is what you're proposing an effort to in fact offset drainage with counter-drainage?

A. That is correct, to the extent that we can.

Q. And what additional increase and recovery are you hoping to achieve?

A. We will only partly be able to counter the drainage, and as Mr. Telford mentioned earlier, we should see an increase of 456,000 barrels incremental.

This is based on two factors. One is the stripping effect of moving more volumes of water through the reservoir from the fractional flow curve.

And the other is the increased drawdown. As we increase the pressure drawdown in the reservoir, we will force the matrix to feed. We have a higher column than Phillips does, so therefore we have more matrix oil than Phillips does. But by increasing this drawdown, we should get the matrix to feed into the fractures and therefore increase recoveries, and that's what the theory says, that's what we're seeing from our production data.

Q. How does the potential for a loss of casing impact the correlative rights of Enserch in the pool?

A. Well, as Mr. Telford mentioned, we have lost 41 percent of our wells out there, we've lost 460,000 barrels of reserves. And if we lose this wellbore, we will not be able to compete or we will not have the opportunity to produce our -- the reserves on Enserch's lease.

Q. Now, you see no adverse impact on the correlative rights of Phillips; is that right?

A. None at all.

Q. What impact would there be on the correlative rights of Enserch if in fact the Application is denied?

A. Phillips will still enjoy an advantage and Enserch will not be able to compete with Phillips. Basically, we'll be denied the opportunity to compete.

Q. Were Exhibits 13 and 14 prepared by you or under your supervision?

A. Yes, they were.

MR. CARR: At this time we move the admission of Enserch Exhibits 13 and 14.

CHAIRMAN LEMAY: Without objection, Exhibits 13 and 14 will be admitted into the record.

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

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. I'm sorry, is your last name Burkett?

A. Burkett, yes, sir.

Q. Burkett.

A. Yes, sir.

Q. Mr. Burkett, describe for me again, sir, what is it that you do?

A. I am the district petroleum engineer. I'm over engineering operations for the west Texas district for Enserch Exploration. My regional boundaries are the Rocky Mountains, west Texas and New Mexico region. I'm responsible for all engineering operations.

Q. All right. Now, within the context of your work --
A. Yes, sir.
Q. -- are you applying reservoir engineering experience to this hearing?
A. Yes, sir.
Q. All right. Do you also have in your capacity the production responsibilities that we would see with a normal production engineer?
A. Yes, sir, we're responsible for production and reservoir engineering, all production reservoir engineering functions.
Q. All right. You would be familiar, then, with how the Phillips 2 A well and your Number 1 well are configured?
A. Yes, sir.
Q. All right. Both those wells have 5-1/2-inch casing, I believe?
A. I'm not certain of theirs, but I am certain of ours, yes, sir.
Q. Are you aware that both wells are using approximately the same size high-volume lift system?
A. I have heard that Phillips has installed a larger submersible pump. I've heard that, it's been hearsay.
Q. All right. The rates of production on your well

that we've used in your model --

A. Yes, sir.

Q. -- were you using 500 or 600 barrels of oil a day?

A. Those were based on the last test we had, which was -- actually, I used a -- I used 4403 barrels per day of total fluid, and the permeability we used was a combination of oil and water permeability.

Q. Okay. Let me see if I understand how you've constructed the model --

A. Okay.

Q. -- upon which you've based your conclusions. I have seen that done, that this basic engineering model was simply a depletion drive reservoir.

A. Okay.

Q. Is that not what this is often used for?

A. Yes, it is. In fact, we varied it for a pseudo-steady-state. But for this -- for trying to simplify the model, we've gone back to a steady-state flow with a constant pressure boundary at a half a mile. It's an arbitrary number. We varied it from 1320 to a mile. We played around with it. It still exhibits the same results, regardless of what we use for RE, regardless of whether we use pseudo-steady-state or steady state. the basic concept is still the same.

Q. All right. You're using a computer-assisted program of some kind?

A. Yes, sir, a spreadsheet with simple Darcy's law.

Q. All right. This is not one of those sophisticated reservoir simulations where you're putting in these reservoir parameters and modeling the performance of these two wells within a certain container?

A. No, sir.

Q. All right. This model does not have inputted into it the geologic conclusions that Mr. Faigle has described for us in terms of size, shape and structural position?

A. Other than feet of pay, no, it does not.

Q. All right.

A. It's a very simplified model.

Q. When we look at this model then, what we're looking at is a container of a certain horizontal dimension, if you will?

A. Yes.

Q. What dimension did you use?

A. I used a drainage radius of 2640, one-half mile.

Q. And the model uses one well?

A. One well, yes, sir.

Q. And within that horizontal extent, you also have a vertical component?

A. Yes, sir.

Q. Within that container, then, the assumptions of the model are that they will have a certain uniform porosity?

A. Yes, sir.

Q. It assumes a certain uniform permeability?

A. That is correct.

Q. It will make no differentiation as to structure?

A. That is correct.

Q. It will not take into consideration whether or not this is a bottom water drive or an edge water drive reservoir?

A. That's right.

MR. KELLAHIN: All right, no further questions.

CHAIRMAN LEMAY: Thank you.

MR. CARR: I have one question.

REDIRECT EXAMINATION

BY MR. CARR:

Q. In this model, is porosity a factor?

A. No, it is not a factor.

MR. CARR: That's all.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. What was the KH at both wells?

A. We determined this with an iterative procedure, it was trial and error. And in the Lambirth Number 1, I used 208 millidarcies with 72 feet of pay.

Now, Mr. Faigle had reported a pressure buildup test that was done in 1978 of 500 millidarcies. And that is correct, that was a pressure buildup test done at that time. It was based on 50 feet of pay instead of 72 feet of pay. So the numbers are approximately correct.

My permeability or the permeability I've used here is a combination of oil and water. That permeability was calculated back when it was totally oil saturation. So it's close.

On the Lambirth A 2 well, our iterative calculations, we came up with 94 millidarcies and 30 feet of pay. This is substantially higher than was reported from core analysis, and I'm concerned that maybe core analysis -- maybe they used plug cores instead of hole cores, maybe. But it -- Had I used their lower number of about three to four millidarcies, it would make the no-flow boundary even further on our lease.

So I've just gone with what fits, just using the data that fits.

Q. And is there any engineering evidence that that supports the fractures?

A. Yes, sir, there was a study done by RPI that shows a permeability distribution, and they also showed a bimodal distribution of fracture and matrix porosity.

Q. That was based on cores?

A. On cores, yes, sir.

Q. Very good.

A. And that was presented in the Examiner hearing previously. We submitted that as an exhibit.

COMMISSIONER WEISS: Thank you, I have no other questions.

CHAIRMAN LEMAY: Commissioner Carlson?

COMMISSIONER CARLSON: That's all right. He covered it.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. I probably should have asked this early on, but I'll ask you because it's a question I had and didn't ask.

The Pennsylvanian oil and the Fusselman oil, are they similar?

A. They're very similar.

Q. So it would be hard to differentiate between the two?

A. It would be, yes, sir.

Q. Bear with me; I'm a geologist, not an engineer.

A. Okay.

Q. You have this drop of oil there, and depending on which way it's going to move, you've done that with pressures.

A. Yes, sir.

Q. But with a water drive reservoir wouldn't that drop of oil just stay there and you'd have the movement from the bottom up of water so that -- The molecules aren't going in either direction, but what you're trying to control is the rate of water coming up the pay section, aren't you?

A. That's right. According to how we see the reservoir, this drop of oil would have to be in the matrix, because the water has already moved above -- You know, it's already watered everything out through the fracture system.

Q. Okay.

A. And so the pressure is pretty much equalized.

Q. Okay.

A. Now, when we increase -- when we install the high-volume lift, we increase the drawdown, we're pulling the water through the fractures. Well, finally we're getting this little drop of oil to come from the matrix into the fractures.

Phillips is doing it from their end, we're doing it from our end, and that drop of oil would be at some point, according to this model, on our lease, would be that no-flow boundary where the drop of oil in the matrix would come out into the fractures and have to decide which way to go, whether to go to Phillips' well or our well.

Does that confuse you?

Q. Yeah, it does.

A. Okay.

Q. You're changing a water drive reservoir, then, to a gas-solution-type drive reservoir? Or what happens with the oil in the matrix that's coming into the fracture system? Is it going to be influenced by some water that's in the fracture system there or what?

A. It should be, and what we feel we're doing with the high-volume lift is pulling so much water through the fractures, and perhaps four or five pore volumes of water through the fractures, that any matrix oil that seeps into the fractures will ultimately end up in the wellbore.

And so the way we envision the model, as we increase the drawdown or we pull harder on the fractures, we're able to alleviate oil -- or move oil from the matrix into the fractures.

Q. So your whole reservoir has become a different mechanism; you're sucking the oil out of the matrix, rather than letting the water move the oil up into the wellbore?

A. That's correct, yes, sir, that's correct.

In effect, it goes back to what Mr. Faigle was talking about, about we've watered everything out. You know, we've watered out the fracture system. We still have matrix oil in place.

You know, we have a higher amount of matrix oil than does Phillips because we were located higher above the oil-water contact. So while -- We have a lot more bypassed oil than Phillips does, because we're located higher structurally. And as we increase drawdowns then we should recover more -- larger amounts of oil, because we have more oil in the matrix system. So we should recover higher volumes from high-volume lift.

Phillips has done this for about three years, and they recovered a lot of oil, but they're not as high in the column, so they haven't recovered as much as we should, because we have a higher column, a higher matrix oil column.

Q. Any idea of percentage of total oil in place in the fractures and in the matrix?

A. I'm not aware of any, I'm not aware of any.

Q. Well, it looks like you've got a half a million barrels left.

Do you know how much the well has produced already?

A. With a million barrels, right, at a million barrels. It's been a very, very good well.

Q. Yeah. So basically there's more oil in the fractures, I guess, than in the matrix to start with, and now you're working on the matrix, which is harder to get out?

A. Probably it's going to be harder to get out. We'll probably leave a lot of oil behind.

Q. How much, percentage of oil in place?

A. I haven't done any calculations on it, but the drawdowns we're seeing -- most of our drawdowns occur in the first 150 feet. So I think the bulk of our recoveries, you know, come from that 150 feet. We feel like we'll leave a lot of oil in place.

CHAIRMAN LEMAY: Take a break? Fifteen-minute break?

(Thereupon, a recess was taken at 10:35 a.m.)

(The following proceedings had at 11:00 a.m.)

CHAIRMAN LEMAY: Does that complete your --

MR. CARR: That concludes our presentation, Mr. Chairman.

CHAIRMAN LEMAY: Thank you.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

We're going to present two witnesses to you. Scott Balke is a petroleum geologist with Phillips. He testified at the original Examiner hearing. I'm going to call him first.

The second witness is Jack Pickett. Mr. Pickett is a petroleum engineer. In addition, he also testified before Examiner Stogner.

At this time I'll ask Scott to take the witness stand.

SCOTT BALKE,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. For the record, would you please state your name and occupation?

A. Scott Balke, I'm a geologist for Phillips Petroleum.

Q. On prior occasions, Mr. Balke, have you testified before the Oil Conservation Division in the capacity as an expert in the area of petroleum geology?

A. Yes, I have.

Q. Summarize for us your education.

A. I got an undergraduate degree at the University of Colorado; a graduate degree, Oklahoma State University.

Q. In what years, sir?

A. Undergraduate degree was 1978 through 1982; graduate degree was 1982 to 1984.

Q. Do you have geologic experience in southeastern

New Mexico, west Texas?

A. Yes, I do.

Q. Does that experience include the Fusselman production that we've talked about this morning and what is identified by the Division as the South Peterson-Fusselman Pool?

A. Yes, it does.

Q. How did you first become familiar as a geologist with that particular production?

A. Originally I was part of the RPI study. There was a consortium of companies who did a Siluro-Devonian study in west Texas, New Mexico.

Q. That RPI study was referenced by one of Mr. Carr's witnesses a while ago. Describe for us what that was.

A. The study was a group, it was a consulting group out of Boulder, Colorado, that wanted to study the particular characteristics of Siluro-Devonian throughout the Permian Basin, and so each -- several of the oil companies gave both money and cores and information to the study so they could all collaborate the information and get the best results from all the information available.

Q. What's the particular time frame for that RPI study?

A. It started -- gosh, probably back in -- The original beginning work was probably back in 1988, something like that. The conclusions took place probably late 1989, something like that.

Q. Apart from contributing to that study effort, do you have other independent involvement with the Fusselman production in this pool?

A. Yes, my duties -- We're responsible for all fields within New Mexico, and part of those were the South Peterson field here.

Q. How many years of your professional geologic experience includes your involvement with the Fusselman Pool?

A. Close to six years.

Q. In addition, did you make a specific study of and geologic conclusions and recommendations to Examiner Stogner back in the June, 1994, hearing?

A. Yes, I did.

Q. Have you continued to study the geology involved in this particular pool?

A. Yes, I have.

Q. And based upon that study, do you now have certain geologic conclusions and opinions?

A. Yes, I do.

MR. KELLAHIN: We tender Mr. Balke as a geologist.

MR. CARR: No objection.

CHAIRMAN LEMAY: His qualifications are acceptable. Balke, is it?

THE WITNESS: Yeah, B as in boy, a-l-k-e.

CHAIRMAN LEMAY: Thank you.

Q. (By Mr. Kellahin) Mr. Balke, what I think I'm going to do is take some of your exhibits out of order. I think I -- I don't want to surprise you, but I'd like to take that cartoon that you have prepared so that we can have you characterize the reservoir for us.

A. Okay.

MR. KELLAHIN: Can you see that, Mr. Carr?

MR. CARR: No, if I can step over --

MR. KELLAHIN: Now can you see it?

Q. (By Mr. Kellahin) Let me direct your attention to what we've marked as Phillips Exhibit Number 6, I believe it is.

A. Five.

Q. I'm sorry, 5. What's the base display?

A. What you're seeing here is very much --

Q. I'm sorry, I asked you the wrong question. Looking -- Where did that display come from originally?

A. Oh, excuse me. It came from Mr. Faigle's presentation back in June.

Q. What then did you do to his characterization or representation of the reservoir?

A. I tried to implore [*sic*] our understanding of the water drive mechanism of the reservoir and how it applies to the geological framework.

Q. Let me divide this into sections for you, Mr. Balke. If you would give us a characterization of the Fusselman reservoir, what kind of rock are we looking at? What's its deposition? Just give us a general summary geologically of how you would characterize the reservoir.

A. The geological parameters I'm going to show came from the core that we took in the Lambirth 2 A and the geological work I did throughout the field.

I agree with Mr. Faigle that it is a fractured dolomite reservoir, heterogenous, fracture with matrix porosity. The porosity comes from both the fractures and from the matrix -- intercrystalline porosity itself. The key --

Q. Do you subscribe to the theory that this reservoir is a dual-permeability system?

A. Dual-permeability system, but with a significant factor of being only fractures, being your core permeability, I guess your primary permeability component.

Your fractures are going to be your conduits, with your matrix porosity being your storage capacity. Your fractures are going to be what's going to transport the oil from both the fracture system and the matrix up through the borehole.

Q. Characterize, then, the reservoir, please.

A. It's a highly fractured permeable reservoir where your communication within your reservoir occurs throughout the reservoir itself, throughout the Fusselman itself.

You -- Again, like I previously said, your fractures are going to be your conduits. It's just like a building with doorways and hallways. Your rooms are going to be where the storage capacity is going to be, but to get through the rooms outside, you've got to go through the hallways, which are the fracture systems.

Q. What is the trapping mechanism by which the hydrocarbons were accumulated and stored?

A. Structurally trapped and stored both within the fractures and within the matrix porosity.

Q. Is there a water component to the reservoir?

A. Yes, there is.

Q. Do you have an opinion as to where the original oil-water contact was in this reservoir?

A. The original oil-water contact is going to be very similar with Mr. Faigle's.

Q. So you don't have any disagreement with him --

A. Don't have any --

Q. -- as to the subsea depth at minus 3450?

A. No problems at all.

Q. Do you subscribe to the theory that this is an active bottom water drive reservoir?

A. Not only an active bottom water reservoir -- bottom drive reservoir, there's a key component, probably a significant component of an edge water drive reservoir. This is based upon geological maps and performance of the wells.

Q. If we look at Mr. Faigle's cross-section that is on the other display board, and if you'll look at the red line that depicts the minus 3450 subsea location of the original oil-water contact, describe for us why you as a geologist do not agree that this is an exclusive bottom water drive reservoir.

A. If -- Just like Mr. Faigle said, if you had had a constant bottom drive reservoir, giving some slack and some variances granted, you would see the water rise in each one of these wells, you'd see the lower structural wells water out or see at least water encroachment earlier than the wells up on top.

And when I show you my structure map, I will show you wells that watered out and produced a lot more, significantly more water, with the same structural elevation. So that proves that it can't be a single bottom water drive, because you have the same subsea depth wells watering out at different times, significantly different times, so it could not be a single bottom water drive.

Q. Can you give us an illustration of a comparison between two wells --

A. Uh-huh.

Q. -- where you would have expected one well to have substantially increased its water cut if in fact it was being affected by water -- a bottom water drive mechanism?

A. Yes, sir, if you could look at my Exhibit Number 3, which is a structure map on the Fusselman itself, within Section 31 there we have a Number 2 well, which is our Enserch 2 A well, which is a subsea depth of minus 3419, and the Number 1 well, which has a subsea depth of minus 3406. Actually, our Number 2 well is slightly structurally lower than the Number 1 well there.

However, water -- and in fact the water -- or the well became uneconomical because of water much earlier in the Number 1 well than it did in the Number 2 well. Now, if this was a strictly bottom water drive, that phenomenon would not take place.

Q. When you compare the Enserch Number 1 Lambirth with the Phillips A 2 Lambirth in terms of the approximate time frame within which each of those wells began to experience substantial increases in water cut, what's the relationship and what did you see?

A. The Number 2 well should be encountering water before the Number 1 well, and that's because it's structurally lower. You have a complete fractured reservoir right there, so they're in communication with themselves. And you would see the Number 1 well, being structurally higher, seeing water much later.

Q. And what happened?

A. That is the case.

Q. Describe for us, then, geologically what you see to have occurred as we look at Exhibit 5, the cartoon.

A. Uh-huh.

Q. With the original oil-water contact as you see it and with these wells and this geologic data, describe for us what's happened.

A. Well, because this was a -- this fracture system was not only fractured but it also had solution enhancement done for diagenesis, you had significant communication within the wells. And as the Number 1 well increased its rate, and because of its structurally favorable position, you're going to see water encroachment coming up at an accelerated rate, especially if it's produced at a higher rate, and will prematurely water out our Number 2 A Lambirth.

Q. When you say "water coming up", can you describe for us in what directions this water is encroaching?

A. It will come up from the edge, along with the bottom, but it will also come up from the edge, because we see, based upon our structure map and based upon our well performance, that there's a strong edge water drive component to it. So you'll see water coming up on the edge of the reservoir itself.

Q. Have you also studied the structural relationship between the Enserch Lambirth 1 and the Phillips Lambirth A 2 well?

A. Yes.

Q. What is your opinion about the vertical difference in the top perforations between those two wells in this pool?

A. The Number 1 Lambirth well will experience a structurally favored position of about 38 feet, approximately 38 feet, and that will give them a significant structural advantage over our Number 2 well.

And that advantage, because of the structure and because we're seeing that the fracture patterns are all broken up so that the reservoir is in communication with itself, will be a significant advantage for Enserch over Phillips.

Q. Mr. Faigle subscribes to the proposition that at this point in the reservoir, if there was an advantage structurally, it simply no longer matters for remaining oil production because the fracture system is watered out.

Do you agree?

A. Well, I'd even kind of piggy-back on top of what Mr. Burkett also said: It takes the matrix to feed into the fractures to produce the oil. Your storage capacity is in the frac- -- excuse me, is in the matrix. And it's the fractures that are going to be able to bring the oil to the well itself.

So I don't agree with Mr. Faigle because I think that your fractures are not watered out, they're just carrying the remnant oil that they carry and also the oil that's coming from the matrix.

Q. In your opinion, does the structural differentiation between the two wells still matter in terms of remaining depletion of the reservoir?

A. Significantly, without doubt.

Q. From a geologic perspective, will rate matter?

A. Yes, it will.

Q. In what way?

A. As you see, both on the diagrams and on this structure map, you're having this reservoir being in communication with itself, both -- There's no vertical permeability barriers, there's no horizontal permeability barriers. With the wells being higher up on the structure, you'll have the advantage.

Is that -- I think I've lost your question a little bit, but maybe that answers it.

Q. Well, let me ask you a different way. If the maximum oil rate is still 267 a day and continues the historical level of that withdrawal rate, versus increasing it to 500 barrels a day, does it matter?

A. Yes, it does. If you increase your rate, you will have adverse effects on Phillips wells, on the Phillips Well Number 2, to be specific. Increased rate will increase the water into our well.

Q. When we look at the producing interval in the reservoir above the original oil-water contact, do you see variations in porosity as we move through the reservoir?

A. There are some variations. However, it's pretty consistent at about 9.5 percent, the core analysis that was done, but on the Number 2 well was hole-core analysis. But the key component -- And we can get to it if I may?

Q. Yes, sir.

A. Go to Exhibit Number 5.

Q. I'm sorry, I think you're looking at 4.

A. Excuse me, you're right, 4.

Q. All right, we'll get it straight yet.

A. Okay.

Q. Four is RPI information from the study?

A. That's correct.

Q. Take a moment and identify each page, and then let's go back and talk about what it means.

A. The first page is a cross-plot of core porosity and permeability in the Phillips Lambirth A Number 2.

The second page identifies the distribution of core permeability from samples. So you've got core permeability versus the percent, where it's at.

What I want to show from both of these is, one, yes, there is a heterogenetic relationship in permeability. However, when you compare porosity as on the first page, porosity compared with permeability, you see not a direct relationship at all.

Porosity stays pretty consistent through there, about 9.5 percent. However, permeability can range from being a moderate-permeable rock to a very high-permeable rock. And it's a very high-permeable rock that makes this reservoir a very -- in communication with each other.

Q. When we look at the first page of Exhibit 4, the figure 9.110, specifically what are we looking at?

A. Looking at --

Q. The first page of this exhibit.

A. Yes.

Q. What is that?

A. That's just, again, a correlation between porosity, core porosity, and core permeability within the

Lambirth A Number 2, and showing zones of both moderate porosity -- or moderate permeability and high permeability within a -- essentially the same permeable rock, around 9.5 percent.

Q. How is that of any importance to us in whether we change the rate of oil withdrawals from the pool?

A. The key component here is permeability. We know it has high permeability. So if you change the rate, you're going to have adverse effects on wells that are structurally low to the one that's on high, the highest structural well. It will have an adverse effect on the Lambirth 2 A.

Q. Page 2 of Exhibit 4, it's figure 9.111. Specifically, what are we looking at here?

A. You're looking at essentially the core permeability of the rock itself, and what we're seeing is that the permeability -- just another correlation of the permeability variation.

It shows that it is a heterogeneous -- has heterogeneous distribution, and RPI's conclusions were that this resulted in premature water breakthrough in the reservoir, could allow for that.

Q. Put that last sentence in some kind of geologic context for us so we can see its significance as we address how these two wells compete for the remaining oil.

A. What we saw was, this reservoir was not atypical from any other carbonate reservoir within the Permian Basin. You had highly permeable rock. You know, if you had too fast of expulsion of the fluids themselves, specifically the oil, you could have premature breakthrough of the water through the -- into the borehole, which -- I mean, it's a direct relationship to what Enserch is proposing here. If you increase the rate too fast, you have bypassed oil.

Q. How does the fact that in your opinion there is an edge drive water component to the reservoir fit within the context of the potential for premature water breakthrough in the reservoir?

A. Okay, you're going to have increase of water coming up from the edge. And along with the strong -- Because of the strong water drive, you're going to have premature water breakthrough because it is very highly permeable, and you'll have increased water within certain downdip wells.

Q. When you look at the porosity characteristics in the log for the Enserch Lambirth 1 well -- A copy of that is on the display board. When you look at the lower perforations within that section versus the higher perforations, is there any distinguishable difference in ranges of porosity?

A. Yes, there are. There's -- Where they perforated was in the higher permeable -- or excuse me, higher porosity zones. And then where they didn't perforate was in the lower porosity zones.

Q. In the lower porosity zones, what range of porosity values do you find in their well above the oil-water contact?

A. Probably an average porosity of, say, around ten percent.

Q. And as we move up into the area of the reservoir that they did perforate, what kind of porosity value are you finding?

A. Probably a low of a cross-plot porosity of, say, 12 percent, to a high of close to 18, 20 percent, somewhere around that range.

Q. When you read across and correlate those points to the porosity values on your 2 A well, what kind of porosity value do you have?

A. Cross-plot porosity of approximately 12 percent.

Q. Is there a material difference in terms of porosity values, then, between the two wells?

A. Yes, there is.

Q. Okay, with the advantage lying where?

A. The advantage lying with the Enserch Number 1 well.

Q. Let me go back and have you identify those exhibits that we haven't specifically addressed.

If you'll look at Exhibit 1 and for the record describe and identify that display.

A. Exhibit 1 is a base map of the South Peterson field itself, and Section 31 gives you the wells in question, specifically the Enserch well, which is located in the northeast of the southwest quarter; the Phillips 2 A well, which is located in the southeast of the northwest quarter of Section 31. And each well has its well number and operator number above it.

Q. How did we end up, just for historical information, in this checkerboarded fashion, Mr. Balke?

A. It was Phillips' farmouts, and Phillips gave a farmout on a checkerboard-type arrangement. Therefore, if Enserch -- which in this case they did, they were successful in their initial well, we would have offsetting to locations to develop ourselves.

Q. Exhibit 2, you don't have to describe it in detail, but just tell us what it shows and the point of time at which you tabulated the production data.

A. Production data was current through 12 of 1993. The Enserch Well Number at that time had done just a little bit below a million barrels of oil. Our Number 2 A well had done approximately 410,000, 411,000 barrels of oil.

And you'll see the production around each of the other wells also.

Q. All right, let's go back then to Exhibit 3, which is your structure map, and let's spend a few minutes on this. This represents your work product, does it not?

A. That's correct.

Q. When we look at the trapping mechanism in the reservoir, describe for us how you've illustrated that.

A. The trap within this reservoir is structural. The structure experienced both fracturing and subareal exposure, with truncation of the Fusselman directly below. That wavy line right there shows the erosional and conforming pinchout.

And near the pinchout, you'll see some of the wells that well performance isn't quite as good. This is because of their location to the pinchout with clay infill within some of the fractures themselves.

Q. When we look at the point on which you're contouring, it is what, sir?

A. What I consider the top of the Fusselman.

Q. All right. Is there a log or some point that you can show us on another display that will give the Commission a reference to where that is?

A. We could use Enserch's cross-section right here. I have no debate with where they're calling the top, the --

in this case they're calling it the lower paleozoic carbonate; I call it the top of the Fusselman. Basically the base of the Penn.

Q. I'm going to hand you Mr. Faigle's Exhibit 3 on which he has prepared his cross-section.

There are obvious differences between your structure map and his structure map. Would you explain to us what those differences are?

A. Okay, just a second, let me just check his numbers.

I believe the difference is, he's picking it -- The significant difference is, I guess, the Number 1 well, I've got it a little bit deeper. He's picking it a little higher, looking more into the porosity range or, I guess, deeper into the rock itself.

But both of us show a structural high up on the Number 1 with truncation to the south, and both Enserch wells and Phillips wells around the Number 1 being structurally lower.

Q. With those general points of agreement, is there any material difference in terms of the contouring conclusions, whether you choose Mr. Faigle's style or your style of identifying the reservoir structure?

A. None whatsoever. Both of us have the Enserch Number 1 well being structurally high and the Phillips well, the 2 A Lambirth, being structurally low.

Q. If you'll look at your structure map, then, can you use that to illustrate what we would have expected to happen to this group of wells had this reservoir been an exclusively bottom-drive reservoir?

A. If we look at Mr. Faigle's exhibit here, you would see that the Lambirth 2 A, the Lambirth Number 3 Enserch, and the Lambirth Number 3, and the Phillips 1 A Lambirth, would essentially have -- and barring some differences -- would have watered out essentially all at the same time, approximately the same time.

Yes, there's going to be some variances there, but they'll be relatively minor. But you'd see each one of those wells becoming uncommercial, uneconomic at about the same time.

Q. And did that happen?

A. No, it did not.

Q. Based upon your work, your study, having heard their presentation, summarize for us your geologic conclusions and your concerns within the context of this particular case.

A. My conclusions are, and very similar to Mr. Faigle's in many ways, is that it is a highly fractured dolomite reservoir, heterogeneous, the fractures being highly permeable, some oil being left remaining within the matrix itself and possibly within the fractures.

Because of diagenesis, subareal exposure and solution enhancement, this is a very highly permeable reservoir with no vertical or horizontal permeability barriers within this reservoir.

My concerns are for Phillips that, Enserch being highest on the structure, Phillips having wells on the -- lower on the structure, particularly the Number 2 A Lambirth, will see water encroachment considerably earlier and will be detrimentally affected by Enserch's proposal here to increase rate.

Increasing rate will have adverse effects on Phillips' wells, because you'll have water coming earlier.

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

We move the introduction of his Exhibits 1 through 5.

CHAIRMAN LEMAY: 1 through 5 will be admitted without objection.

And your witness, Mr. Carr.

MR. CARR: Thank you, Mr. LeMay.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Balke, several things we're in agreement on. We do agree we've got a dual-porosity system or a bimodal system in the reservoir?

A. In process, correct.

Q. And we -- Is it fair to understand that the fractures are the primary conduits for the movement of the oil to the wellbore?

A. That's correct.

Q. In your opinion, is there much oil left in those fracture systems at this time?

A. That's probably more of a -- for Mr. Pickett to address, but I would think there is significant oil still left to be remaining.

Q. Should I address questions about where remaining oil would be, matrix versus fracture system, to Mr. Pickett?

A. That would be fine, or however you would like.

Q. Do you have an opinion as to whether or not the bulk of the oil to be recovered is within the matrix?

A. I think your matrix is probably your storage facility, and your -- and the remaining oil, in my opinion, probably would be in the matrix.

Q. And is it fair to say that to get that oil out of the matrix you have to have something in the reservoir to cause it to move, like a pressure differential; is that not true?

A. I'll leave that one for Mr. Pickett.

Q. Now, if I understood your testimony, you agreed that this is a water bottom drive, but there is also a side water drive component in it; is that correct?

A. That is correct, a significant, probably the pronouncement [*sic*] of the edge water drive, correct.

Q. If we look at the cartoon you have presented, this is not really designed to be an accurate representation of what's occurring in the reservoir, is it?

A. I think it's a conceptual model of what's occurring in the reservoir.

Q. Now, it basically, if we look at it, it shows the water contact. Is that that blue line that runs across it? Is that an oil-water contact in the reservoir?

A. I would say that's where you have an approximate commercial line. I think your oil-water contact could be significantly higher, but that line will probably be where you have so much water that your wells become uneconomical to produce.

Q. If we have a well like the Lambirth Number 1 that has a 90-percent-plus water cut, it would be logical to expect that there would be some substantial water in the reservoir above that line; is that not fair to say?

A. Fair to say.

Q. If we look at this cartoon, and if we had just a bottom water drive reservoir, in fact, we would see an oil-water contact that would be actually the reverse of what we've got here; isn't that right?

The wells that were producing would be pulling the water -- pulling on the aquifer and pulling it up, not -- So you would have it actually rising in the center, not dropping, if it were just a bottom water drive; isn't that correct?

A. That would be correct.

Q. And in fact, the wells that were pulling the most would be coning water up into those wellbores?

A. That would be correct.

Q. But you're not seeing that here in a predominantly bottom water drive reservoir. What this shows is effect -- the -- what occurs with a side water drive; isn't that right?

A. Correct.

Q. And yet it is fair to say that the dominant reservoir drive mechanism is a bottom water drive?

A. I would say that's not what I -- my geological parameters or my geological conclusions came to, but I would again defer that with Mr. Pickett.

Q. So you're not telling us what kind of a water drive we have in the reservoir?

A. I think our conclusions, from my geological conclusions, say that it's a component of both edge water and bottom water drive, and I'd say that a significant contribution is probably edge water, based upon what I see in my structure map and well performance.

Q. And my question is, this cartoon does not show the effect of bottom water drive; it shows edge water drive?

A. It does show bottom water drive, because you do have the bottom portion of the blue coming up from the original oil-water contact. It just shows a more significant edge water drive than just a strict bottom water drive.

Q. And this doesn't, in fact, really show any of the effect of a bottom water drive, or we'd see this line coning up into the wells that are pulling on the aquifer?

A. Well, what you're dealing with -- what you're specifically saying is where the original oil-water contact is. That's not what I'm showing here. The blue is not an oil-water contact, but where my economic -- perhaps an economic water contact may be.

Q. And it doesn't show the effect of pulling, the wells that are producing the hardest, it doesn't show the effect that has on this bottom line?

A. That is a conceptual diagram with what I'm seeing off of my structure map itself.

Q. Rate certainly matters, you testified, in the way these wells are produced?

A. Correct.

Q. And the rate at which the wells are produced -- i.e., the Lambirth, the Phillips -- the Enserch wells produced, you testified, would have an impact on the Enserch well; isn't that what you testified?

I'm sorry, the Enserch well's rate of production would have impact on the Phillips well?

A. Yes.

Q. All right. If I could remember who everybody was, it would be easier.

A. Right.

Q. All right. Isn't that because of the drawdown effect on the reservoir by producing these wells? If we produce our well faster, there would be a greater drawdown?

A. When we get to specifically speaking about drawdown, again, I would defer to Mr. Pickett.

But in a geological sense, I would say that what I'm seeing here, based upon my structure and well performance, is not a single bottom water drive.

Q. And so you're not testifying about the effect of the drawdown on -- from our well on the Phillips well?

A. What I'm testifying here is saying that it's not a strict bottom water drive reservoir, that the reservoir is fractured and in communication with each other and has no barriers, and from a geological perspective, based upon my geological evidence and well performance, that we'd be adversely affected by increasing the rate by Enserch.

Q. And the increased rate, the adverse effect of the increased rate comes from what? Pressure drawdown?

A. Increasing the water in a lateral sense into our wellbore.

Q. And it would also increase the water in a vertical sense, coming up into the reservoir, would it not?

A. There will be some significant increase from the bottom, correct, but I think your major component would be from the side.

Q. We looked at the reservoir, and I believe you testified looking at exhibits from the study that you participated in, and you concluded that the higher permeabilities in the reservoir would in fact cause higher drawdowns. Did you testify to that?

A. I didn't say higher drawdowns. I said that the higher permeability within the rock would pose no communication -- or -- exactly, communication barriers between the rocks. I see nothing in there. They should be all in communication with each other, based upon these higher permeabilities.

Q. And so you looked at the fact that they're in communication with each other. Did you take that the next step and talk about the impact withdrawals from one well would have on the other, or is that again something for Mr. Pickett?

A. I will defer that to Mr. Pickett. However -- No, I'll just defer that to Mr. Pickett. He can explain that, hopefully, a little bit better than me.

Q. We look at the permeabilities from the study, and if I look at the second page of your study it shows a permeability, I believe, for your Lambirth 2 A of 3.8 millidarcies; is that right?

A. That's correct.

Q. And you would agree with me that the permeability in the offsetting Enserch well is 500 millidarcies?

A. That was determined based upon a totally different parameter. We're looking at core permeabilities right here. Your test gave well-performance permeabilities.

Q. Do you have well-performance permeabilities on the Lambirth A Number 2?

A. I again will give that one to Mr. Pickett. All I can -- really concerned with what I know as far as geology in the reservoir.

Q. When we look at the time frame within which the various wells in the reservoir have watered out, do you have a definition for me of what watering out actually means?

A. For us it would be when it became uncommercial to produce. Our lifting costs would be more than what our revenue would be from the oil.

Q. So it would have an economic component and I guess a water component, as Mr. Faigle testified?

A. No, ours would be strictly an economic --

Q. A strictly economic. Did the -- And that is when you totally terminate producing the well; is that when you consider a well to have watered out?

A. Yes.

Q. Has your 2 A watered out at any time?

A. I'm not aware of such.

Q. The 1 A, in your opinion, has not watered out?

A. The 1 A has not watered out?

Q. Yes.

A. We have ceased producing our Number 1 A.

Q. It has watered out?

A. To the best of my understanding, it is, but again I would like defer that one to Mr. Pickett.

MR. CARR: That's all I have.

One other question -- No, I'm sorry, I'll ask that to Mr. Pickett.

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. On Exhibit 4, there's quite a range -- I guess these are all horizontal permeabilities, huh?

A. That's correct.

Q. All right. Do you suppose that the range of the vertical permeabilities is similar?

A. I would be expecting something like it, to be very similar.

COMMISSIONER WEISS: That's all the questions I have. Thank you.

CHAIRMAN LEMAY: Commissioner Carlson?

EXAMINATION

BY COMMISSIONER CARLSON:

Q. When did the Phillips 1 A well quit producing?

A. We shut it in, I believe, November of this last, past year.

Q. And the 2 A well is still producing?

A. That's correct.

COMMISSIONER CARLSON: That's all I have.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Balke, what about the 3 A? That's a well that confuses me. It's higher than the 2 A, and yet it's produced less oil. Is it still producing?

A. 3 A, is this --
Q. 3 A Lambirth, the one south of the Number 1.
A. Okay, that is currently producing, that's correct.
Q. It is not as good a well as the 2 A, even though it is structurally higher?
A. Mr. Pickett will present the production on that, but it does not produce water, it produces around 20 barrels of oil a day.
What we see from our analysis is that you probably had a lot of infilling of clay and other precipitants within the fracture system due to its proximity to the truncation there to the south.
Q. So you might expect that well wouldn't react with your model of having -- being an excellent reservoir, having high permeability both vertically and horizontally and excellent communication-type --
A. Correct.
Q. -- characteristics?
A. And as you pointed out, it is structurally higher. That's why it's not seeing the water that all the other wells are seeing also.
CHAIRMAN LEMAY: Okay, that's all I have. Thank you.
MR. KELLAHIN: You can leave the displays there,

Scott. Take the one you need and --

Mr. Chairman, I've called Jack Pickett to the stand.

JACK PICKETT,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. For the record, Mr. Pickett, please state your name and occupation.

A. My name is Jack Pickett, reservoir engineering supervisor for Phillips Petroleum, located in Odessa, Texas.

Q. What is it that you do as a reservoir engineering supervisor for your company?

A. I supervise other reservoir engineers and then conduct some reservoir engineering studies on my own.

Q. Is this an area, when we look at the South Peterson-Fusselman Pool, that is within your expertise both as an engineer supervisor, as well as a reservoir that you have studied as an engineer?

A. Yes, I worked on the South Peterson Fusselman field in the early Eighties as an area engineer, and -- for about three years. And then I've been in my current position for about seven years, with responsibilities for the whole Permian Basin and -- essentially in New Mexico.

Q. So your involvement in this pool with regards to your production is simply not triggered by Enserch's Application?

A. That's correct.

Q. You've got historical knowledge, separate and apart from your activities in this case?

A. Yes.

Q. Did you testify before Examiner Stogner as an expert in reservoir engineering in this case?

A. Yes.

Q. And have you continued to study the issue of increasing the oil allowable for this pool?

A. Yes.

MR. KELLAHIN: I tender Mr. Pickett as an expert reservoir engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) Mr. Pickett, if the Commission were to grant Enserch's Application to increase the pool allowable for the pool, how many wells would benefit by that increase?

A. One. Just the Enserch Lambirth Number 1 is the only well capable of taking advantage of that increase.

Q. Let me start where I left off with Mr. Balke.

Let's look at Exhibit 5. It's the cartoon that's on the foam board.

As a reservoir engineer, describe for us what you see within Mr. Balke's geologic context as to how the reservoir has been depleted when we use the original oil-water contact of minus 3450. What's happened as the wells produce the fluids from the pool?

A. As the wells have been producing, you can see a lot of edge water or premature water encroachment from the sides, wells that shouldn't have watered out if it was purely a bottom water drive mechanism, watering out before they should have.

Q. All right. Are there illustrations to prove that conclusion?

A. Yes, I'll have several illustrations.

Q. At this point in time, is it still appropriate, in your opinion, to maintain the consistency of keeping the oil rate at 267 barrels of oil a day as the two operators compete for the remaining oil?

A. Certainly no higher.

Q. And why do you say that?

A. The Phillips well will be damaged if -- The function of the water encroachment into the Phillips wells is a function of how much oil Enserch is pulling out of theirs.

Q. When we look at the opportunity to compete for the remaining oil in the pool, how many wells are truly involved in that competition?

A. Three.

Q. All right. Identify for us the three wells that still remain to compete.

A. The Phillips Lambirth A Number 2, the Phillips Lambirth A Number 3, and the Enserch Lambirth Number 1 wells.

Q. Let's look at how you have exercised that opportunity to compete. If you'll look at the Phillips 2 A Lambirth well, how is that well currently configured for production?

A. We've got the largest submersible pump in it that we can put in 5-1/2-inch casing.

Q. And approximately how many total fluid barrels are you able to produce?

A. We're making about 150 barrels of oil and 1500 barrels of water.

Q. All right. Are you familiar with the SPE paper that's been discussed by Enserch in the hearing?

A. Yes, I've read it several times.

Q. All right. When we look at the criteria for accomplishing some opportunity of success with a high-volume lift, have you tried that system in this reservoir?

A. Yes, Phillips has effectively tried that on two wells, and it did not work on either one.

Q. Were you able to try that opportunity within the parameters of the SPE paper where you were dealing with water cuts of between 70 and 95 percent?

A. Yes, both our wells that we installed submersible pumps on had water cuts within that range, and we saw no extra oil as a result of installing submersible pumps, no increased reserves or decrease in water-oil ratio.

Q. As you study information since the last hearing, do you reach any different conclusion about the adverse impact on Phillips' correlative rights if this Application is approved?

A. No, same now as it was then.

Q. Based upon that data, do you have an opinion as to whether or not approval of this Application will increase ultimate oil recovery from the entire pool?

A. I see no information that would indicate increasing the allowable will increase the ultimate recovery.

Q. From the pool?

A. From the pool.

Q. Do you see any information to tell you that the Enserch well has improved its ultimate recovery versus simply accelerated the recovery of the same volume?

A. It's hard to say with a short time period, but it is probably recovering some more reserves, but at Phillips' expense.

Q. Why do you say that?

A. Because it's drawing water in from the sides and watering out Phillips' wells earlier, reducing our reserves and increasing Enserch's reserves.

Q. If we keep the oil rate the same, what does that preserve for Phillips that you don't have if the rates increased?

A. An opportunity to recover our reserves.

Q. You listened to Mr. Burkett's model example of the fact that the advantage is to you --

A. Yes, sir.

Q. -- despite the fact that your well is downstructure, producing less oil and may have less quality in terms of reservoir characteristics?

A. Yes, I heard that testimony.

Q. And what's your opinion?

A. I think it's just the opposite, that Enserch has the advantage and that Phillips does not have an advantage.

Q. What's the flaws, as you see it from a reservoir engineering perspective, in Mr. Burkett's conclusions?

A. Basically, his claim was that Phillips -- the 2 A well was affecting Enserch's well more because we had a greater pressure drawdown, but that's because of the lower permeability.

And if you draw that same kind of reasoning out, you go down to -- if the well had very low permeability, it was only making, say, one barrel of fluid a day, that would even be more of a drawdown, even more of an effect.

So it kind of seems backwards to me that the lower permeability that our well has, the more we affect Enserch, that does not seem correct.

Q. All right, when we look at the opportunity for success under the hypothetical in the SPE paper, is that conditioned on the pressure drawdown that you're able to achieve in the reservoir in that specific well?

A. I believe it touches on that, that it could be a function of the drawdown pressure.

Q. When you look at the other two wells that you tried the high-lift system in --

A. Yes.

Q. -- and could not increase the oil productivity, which two wells did you try that in?

A. In the Lambirth A Number 1 and in the Lambirth A Number 2.

Q. Were you able to achieve a level of pressure drawdown in each of those wells that should have, if the paper were correct, improved?

A. Yes, far beyond what Enserch has drawn their well down, and enough that -- inasmuch as they call -- talk about it in the SPE paper.

Q. All right. And you were not able to achieve the kinds of results that were hypothecated by the paper?

A. Correct.

Q. What do we do, if anything, about this issue of water breakthrough, premature water breakthrough in the reservoir? Is that an issue for you as a reservoir engineer in this pool?

A. Yes.

Q. Why?

A. You have to be concerned about the rates of withdrawals from updip wells, lowering the reserves of the downdip wells.

Q. Let me put this to you a different way. We often talk to this Commission about a reservoir being rate-sensitive or not rate-sensitive.

A. Oh, yes.

Q. In the context of this case, is this reservoir going to be sensitive to rates of fluid withdrawals?

A. No.

Q. All right. What we are concerned with, though, is the opportunity for the movement of the oil within the reservoir?

A. Yes.

Q. So it's a correlative-rights issue, as opposed to a waste issue?

A. Correct.

Q. Let's turn to your exhibit. Your first exhibit is Number 6?

A. Right.

Q. What are we looking at?

A. This is a production plot of Phillips' Lambirth A Number 3 well. It's located one well location south of the Enserch Lambirth Number 1 well.

The oil production is the black line, the water production is the blue line the gas production -- or GOR -- is the red line.

The well is currently making, now, about 22 barrels of oil a day, little or no water, with a GOR of around 1000.

Q. Your perfs in this well are higher structurally than the perfs in your 2 A well?

A. Yes.

Q. All right. And this is structurally higher in the reservoir, as shown in Mr. Balke's structure map?

A. Yes.

Q. It produces zero water and -- what? Twenty-nine barrels of oil in November of 1994?

A. Twenty-two to 30.

Q. All right, and it's currently still producing oil?

A. Yes.

Q. How do you explain this well's performance?

A. Well, if you look at the -- I don't know what you call it. It's fairly inconsistent oil production over the history of the life, but essentially it's flat production for the entire history of the well. I kind of call it non-declining oil production.

And what's also interesting to note is, the gas is still at about the same level it was originally.

What I infer from this information is that this well has got lower productivity than some of the more prolific wells in the field, but it's receiving the pressure support from the aquifer and the water-drive mechanism in the field.

Q. Could this well potentially be affected adversely if the oil rate is increased?

A. This well probably would not be affected.

Q. Let's look to those wells that may be.

A. Okay, the -- One other thing to note on this is that the perforations in this well match up with the top half of the perforations in the Enserch Lambirth Number 1 well, which Enserch has said has watered out, yet this well makes very little water.

Q. All right, you find evidence it's in the same reservoir?

A. Yes.

Q. You find some pressure support for that well?

A. Yes. And --

Q. If it was a true solution drive reservoir and not in communication with the main reservoir, then that shouldn't happen?

A. Right.

Q. So it's getting some support, and it's in the same common source of supply?

A. That's right. And making very little water compared to the other well, especially like the Enserch Lambirth Number 1 well, this is one of the first indications that we have of the edge water drive mechanism in the field.

Q. Let's turn to Exhibit 7. Identify this one for me, Mr. Pickett, and then describe for me what it shows.

A. This is a production plot of the Phillips Lambirth A Number 1 well. Black on this one is oil per day, the red is the water per day, and the blue is the water-oil ratio.

What I'd like to point out is, when the submersible pump was installed in this well in October of

1992, indicated on the exhibit.

Q. All right, at that point what's the approximate water cut?

A. About 87-, 88-percent water cut, or oil-water ratio in about the seven to eight range.

Q. All right. And it's within the range of the parameters of the SPE paper for a candidate for high-lift volume success?

A. That's right.

Q. All right, what happened?

A. We installed a submersible pump, and immediately thereafter the water-oil ratio started rising, indicating that we're not recovering any new reserves, the oil production goes up indicating it's an acceleration of production, but with the water-oil ratio increasing, no new reserves.

Q. By October of 1994, what's your water cut?

A. About 98 percent.

Q. And what did you do?

A. We shut the well in soon thereafter.

Q. So what does this tell you about the use of the high-lift volume system for this well?

A. You can accelerate reserves, but we didn't add any new reserves.

Q. When we look at the perforations' relationship in the A 1 well to the perfs in the Enserch well, which one has the higher perfs?

I didn't say that very well, Jack.

A. Yeah.

Q. Let me try again.

The Phillips Lambirth 1 A --

A. Yes.

Q. -- its lowest perfs are higher than the lowest perfs in the Enserch Lambirth 1, are they not?

A. Can you say that one more time?

Q. Yes, sir. If you'll look at the cross-section --

A. Okay.

Q. -- and it's a little far for me to see, but it appears, if the Phillips 1 A, its lowest perf --

A. The one on the far right?

Q. Yes, sir.

A. Yes.

Q. -- are slightly higher than the Enserch 1 A perfs in the lower portion?

A. Yes.

Q. Except this well is experiencing a higher water cut?

A. That's right.

Q. What does that tell you?

A. Edge water drive.

Q. All right, let's go to Exhibit 8. What's this?

A. This is a Phillips well test report which contains the three producing Lambirth A wells.

Q. What do you want us to see on this display?

A. The Lambirth A Number 1 well, which is the -- There's a partial well test for an unnamed well at the top, a Keystone well, and the third one down is the Lambirth A Well Number 1, the one we just talked about putting a submersible pump on.

What I wanted to show on this one is, on the far right, the fluid level of 6460 feet, which is 4000 or 5000 feet below what Enserch said they drew down their Lambirth Number 1 currently, and it's well below where our Lambirth A Number 2 is being drawn down right now.

The important thing about this one is, this well with the submersible pump was drawn down 2000 pounds, far more than any of the other two wells.

If one of the wells in the field was going to see the effect that is talked about in the SPE paper, this is the well that should have shown it. This one was pulled down harder than any of the other wells, yet we saw no effect, no positive effect, on the water-oil ratio of the water cut by installing a submersible pump.

Q. Does the SPE paper talk about adding pool reserves recovered?

A. No, it never mentions whether the reserves from a pool or a reservoir are increased. It only talks about individual wells.

Q. Exhibit 9, identify and describe that for us.

A. This is a production plot for the Phillips Lambirth A Number 2 well. Oil is the black line, water in red, and water-oil ratio in blue.

What I want to show on this one again is when we installed the submersible pump in February of 1992 on this well, the water cut was in the 86- to 88-percent range, our water-oil ratio in the 6 to 7 to 8 range, before the pump was installed, well within the SPE guidelines.

We put the pump in, the oil rate goes up, the water-oil ratio stays about the same, and then in a few months starts going up.

What I conclude from this is that, again, it was an acceleration project. We're not getting any new reserves, we didn't see any positive effect on the water-oil ratio from installing the submersible pump.

Q. Have you correctly depicted the point in the production profile of this well for the installation of the submersible pump?

A. Yes.

Q. And when we look at that point, what do we see?

A. The oil production going up and no change in the water-oil ratio immediately thereafter.

Q. Where do you get the information on when the submersible pump was installed? Is that from your own records?

A. Yes, Phillips well files.

Q. Is this information accurate and correct --

A. Yes.

Q. -- as you've displayed it here?

A. Yes.

Q. Did you and Mr. Telford back at the Examiner hearing have a difference of opinion with regards to what was happening in relationship to the installation of this pump?

A. Yes.

Q. He had shown the installation at a different point on the plot of this production profile for this well, had he not?

A. That's correct.

Q. And where had he put it?

A. At some point earlier, I don't recall where.

Q. All right. And you have gone back and rechecked, then, and you're satisfied that you have put this on the correct point --

A. Yes.

Q. -- of the production profile?

A. Yes.

Q. There's no opportunity for dispute on that issue at this hearing?

A. Right.

Q. Let's look at Exhibit 10. What is that?

A. This is a production plot for the Enserch Lambirth Number 1 well, oil in the black, the red is the GOR, and blue is the water production.

What I want to point out on this one is that essentially this well came on water-free, in 1978 it produced a little bit of water, in 1985 we're showing 10 or 20 barrels of water per day for a year or so ago, and then it produced essentially water-free again until 1993.

Q. But you're already producing water in -- what? 1980, in the A 2?

A. Yes, in the -- If we go to the next Exhibit, compare the two --

Q. Oh, am I ahead of you?

A. No.

Q. All right, let's do that. Let's compare the 10 and the 11 so that we can look at the Enserch 1, which is Exhibit 10, to the Phillips Lambirth A 2, which is Exhibit 11.

A. Yeah, I'd just like to make a comparison of these two wells. Bear in mind, they're perforated. The bottom perforation in both these wells is at the same subsea depth.

And the Phillips well started making water almost from the very start. When the Lambirth -- the Enserch well makes its first water in 1985, 10 or 20 barrels of water per day, the Phillips well in 1985 is already up to 400 or 500 barrels of water per day.

This is another -- This is strong evidence of our edge water drive.

Q. Do you subscribe to the theory that the fractures are being depleted of oil and are now fully depleted of oil?

A. No.

Q. Why not?

A. The fractures have to be the conduit to bring the oil into the wellbore. The oil is not going to feed directly from the matrix to the wellbore. All the oil has to go through the fractures.

Q. All right. Continue then, with Exhibit 11. What else do we see?

A. Just comparison, that in 1992 or 1993 the Phillips well is up to 1000 barrels of water per day; Enserch is still water-free up to that point.

Q. All right. When we look at November of 1994 --

A. Okay.

Q. -- Mr. Burkett is telling me his well is producing about 600 barrels of oil a day, and I don't know what the corresponding water is, but they are lifting a significant amount of reservoir fluids?

A. Right.

Q. When did you shut in the Phillips Lambirth 1 A?

A. In about November of -- late October or early November of 1994.

Q. Any relationship?

A. We feel that the increased withdrawals from the Enserch Lambirth Number 1 probably did contribute to us having to shut the Lambirth A Number 1 in when we did. It probably would have gone on longer if that wouldn't have happened.

Q. Let's look at Exhibit 12. Identify and describe what you're showing.

A. This is a plot of the water-oil ratio from two of the Phillips wells, the Lambirth A Number 1 and the Phillips Lambirth A Number 2 well.

What's interesting about this plot is that whether you look at the top perforation or the bottom perforation, the Lambirth A Number 1 is higher than the Lambirth A Number 2. I think it's 12 feet above -- The Number 1 well is 12 feet above at the top and about 8 or 10 feet at the bottom perforation.

There was a -- some lower perfs open in the Lambirth A Number 1, but they were shut off in about 1982.

So the Number A Number 1 is higher than the Lambirth A Number 2 in both the top and bottom perforations, yet for the entire producing history of these two wells, the Lambirth A Number 1 has had a higher water cut, higher water-oil ratio, except for a brief six- or seven-month period in 1991. For the other 95 percent of the well's predicted life, the A 1 has had a higher cut than the A Number 2. More evidence of the edge water drive mechanism.

Q. Have you now addressed, or in part of your study did you address the recoveries that Enserch has already obtained from the Lambirth Number 1 well?

A. Yes.

Q. At the point in time that you did your calculation, what was the total cumulative recovery you were utilizing from the Lambirth well?

A. About 980,000, 950,000 barrels of oil.

Q. Mr. Burkett with his testimony has argued for the proposition that their well is not going to affect your well at higher range. Has Enserch provided testimony in the past before the Division that is evidence that leads to a contrary conclusion?

A. Yes.

Q. Let me direct your attention to what you've marked as Exhibit 13. We're looking at the portion of a transcript --

A. I'm missing half of mine.

Q. Are you?

A. Yeah.

CHAIRMAN LEMAY: I just have one page.

THE WITNESS: I've got the second page. Maybe that's all I need.

MR. KELLAHIN: Well, I'm not sure, let me hang on.

COMMISSIONER WEISS: We have different --

MR. KELLAHIN: I think what's happened is that these old -- Yeah, there's two pages to this, aren't there?

THE WITNESS: Yes.

MR. KELLAHIN: Well, how did we cleverly do that? We need both pages, don't we?

With your permission, Mr. Chairman, I'm going to hand the exhibit, the two pages, and I'm going to -- at the conclusion I would like to submit the full authentication from the transcript that will have both pages, and I will hand you my single copy of that now so that you'll have the same references as the witness.

CHAIRMAN LEMAY: Okay, thank you.

Q. (By Mr. Kellahin) All right, Mr. Pickett, I've provided you with copies of pages 21 and 22 from that Examiner hearing in which an Enserch engineer -- I believe it was Mr. Leonard Kersh --

A. Yes.

Q. -- was testifying for his company with regards to information that you have thought relevant and have utilized. What was the point of what he was doing?

A. This is testimony from the previous hearing on this field to increase the spacing from 40 to 80 acres, and the Enserch engineer is testifying about a drawdown test or reservoir-limits test that they did.

And I'll just go to the conclusion of their test, was that the Enserch Lambirth Number 1 well was affecting 830 acres, or approximately 830 acres.

Q. All right. When you take that information, what does it tell you within the context of your reservoir study and Mr. Balke's geology about the opportunity to have the Enserch well adversely affect your opportunity for remaining oil recovery if the rate is increased?

A. I guess it's a combination of them being structurally high and having good productivity. They're able to affect production for a very wide area and draw the oil out a lot faster than some of the other wells can.

Q. Have you tried to visualize or represent, at least in a hypothetical way, on Exhibit 14 an area that would include the 830 acres that Mr. Kersh had testified about being affected by the drawdown test?

A. Yes, we just drew an 830-acre are with the Lambirth Number 1 Well at the center, just to show -- graphically depict what that 830 acres looks like and how it essentially encompasses the entire productive portion of the field at the present.

Q. And that's Exhibit 14?

A. That's right.

Q. And if you were to change the shape so it matched the contours of the geology, it would encompass the entire remaining area of production in the pool?

A. Yes, because of the faulting to the south or the pinchout to the south, the reservoir is really not present where I've got the circle drawn, but...

Q. Let me direct your attention to the final exhibit, which is Exhibit 15. Does this represent your conclusions as a result of work product that you have completed using the disciplines of a reservoir engineer?

A. Yes.

Q. Describe for us what you wanted to find out, the method you used, and the results.

A. Okay. the production numbers -- this is for the Enserch Lambirth Number 1 well -- they're probably about four or five months short now, but it probably is up to a million barrels or so now. But at the time this study was done, at the middle of last year, the Enserch well had cum'd 953,000 barrels of oil, 554 million cubic feet of gas and 37,000 barrels of water.

Q. When we look at the total oil in the pool, what percentage of the total oil has Enserch already recovered from the well?

A. Enserch has recovered 38 percent of all the oil production from the South Peterson-Fusselman field.

Q. What's eight percent mean?

A. Eight percent is that one out twelve, or there's been 12 wells producing or something on that order. Essentially, they've got one out of 12 or 13 wells, whatever one-eighth -- or eight percent works out to be.

But the point of that is just, they've recovered 38 percent of the oil from only eight percent of the wells there.

Q. All right. What's the next item? What's 22 percent?

A. Looked at the percentage of the oil pay that they have in their well and compared to the total from all the other wells, and they had 22 percent of the net oil pay.

Q. They had 22 percent of the net oil pay?

A. Just in -- on a footage basis.

Q. And yet they've already recovered 38 percent of the total oil in the pool?

A. Yes. And took those net oil pays, which -- provided by geology, and just assumed that footage for 80 acres, and then took the average porosity from each well and came up with the oil in place.

Q. That's a volumetric type of calculation?

A. Exactly.

Q. And of the original oil in place, then, they have recovered, by your calculation, 20 percent?

A. Well, they have 20 percent of the original oil in place under their tract.

Q. I misspoke.

A. Right.

Q. For their 80-acre tract, based upon the calculation, they would have 20 percent of the original oil in place?

A. Right.

Q. And already, as of -- What's the date of --

A. The middle of 1994.

Q. -- the middle of 1994, they've got 38 percent of the total oil in the pool?

A. Yes.

Q. What's that tell you about correlative rights?

A. We probably have some reserves moved off -- our oil moved off the Phillips leases onto the Lambirth, Enserch Lambirth Number 1 well.

Q. And what happens if the rate is almost doubled?

A. That situation is aggravated, we lose more reserves.

Q. What would you like this Commission to do?

A. Not grant the Enserch request.

MR. KELLAHIN: That concludes my examination.

We move the introduction of Exhibits 6 through 15.

CHAIRMAN LEMAY: Without objection, Exhibits 6 through 13 or 14 will be --

MR. KELLAHIN: 15, sir.

CHAIRMAN LEMAY: -- 15, I'm sorry, will be admitted into the record.

Mr. Carr?

MR. CARR: Mr. LeMay.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Pickett, if we stay with Exhibit Number 15, I understand your testimony from this exhibit to be that somehow the correlative rights of Phillips have been impaired by the way the Lambirth Number 1 is produced?

A. You could assume that.

Q. Is that what you're saying, that correlative rights have been impaired?

A. I guess they could have been.

Q. Do you understand that in New Mexico correlative rights is defined as the opportunity to produce your fair share of the gas?

A. Yes.

Q. And do you understand you're not guaranteed anything when you drill a well but an opportunity to produce your share?

A. Right, rule of capture.

Q. You're not telling us that in the past you've not had an opportunity to produce the gas from your wells? This Commission has not denied you that opportunity?

A. Right.

Q. And the oil?

A. Right.

Q. And so what we're here today is, we're looking at what's left, where it is and how we produce what's left; isn't that fair to say?

A. Right.

Q. And we're looking at the opportunity to produce what we have today?

A. Right.

Q. And in that context, what is produced in the past isn't relevant to what our opportunity is today to produce our fair share?

A. Right.
Q. And so if we produced 90 percent in the past, we're still looking at what we've got left and what we have before us as of today and our opportunity to produce that?
A. Yes.
Q. Now, I gather from your testimony that you disagree with Mr. Burkett's conclusions about the impact that -- of the Phillips Number 2 A well on the Enserch Number 1?
A. Yes, I disagree with his conclusions.
Q. Have you done any modeling of the reservoir?
A. No.
Q. Have you attempted to calculate the impact that two wells might have on each other?
A. No.
Q. You just don't like what Mr. Burkett has done?
A. I don't think in a water drive reservoir that his calculation is relevant.
Q. But you have not made any calculation of your own to try and establish the impact between the two wells?
A. Because I don't think a calculation would be relevant.
Q. No calculation would be relevant?
A. As far as the pressure drawdown affecting updip wells.

Q. What we're talking about here is really drainage, is it not, between the two wells, the Number 1 and the 2 A?
A. Yes.
Q. And drainage is really a factor of pressure, is it not?
A. In fluid movement.
Q. And isn't fluid movement caused by pressure differential?
A. Yes.
Q. So we're talking about pressure, are we not?
A. Yes.
Q. I believe you testified that -- and would agree with us, that you're achieving a greater pressure drawdown in the 2 A than we are in the Number 1?
A. I don't think I testified to that, but I think that's correct.
Q. You attempted to --
A. It may be about equal. I --
Q. It might be about equal?
A. Yeah.
Q. You're not seeing a greater pressure drawdown in your well than what Enserch has been able to achieve?
A. I believe both wells had fluid levels in the 1500-, 1800-foot range.
Q. What was the fluid level that you -- most recent

one in the Lambirth 2 A?

A. I didn't talk about it, but it's at 1830 feet from the surface.

Q. And then the Enserch Number 1, do you have a depth on that?

A. I think I wrote it down when somebody talked about it.

Q. 1320?

A. 1320, right.

Q. Wouldn't that suggest to you that you have greater pressure drawdown in your well than --

A. Yes, a --

Q. -- in the Enserch?

A. -- slightly greater pressure drawdown.

Q. I believe you told this Commission that you had attempted to install high-volume lift on wells, and you haven't seen any real response.

A. We haven't seen an increase in reserves.

Q. All right, let's take a look at your Exhibit Number 9. This is the production history on the Lambirth 2 A.

A. Okay.

Q. If we take a look at this well and we know where the submersible pump is installed in February of 1992 --

A. Yes.

Q. -- if you calculate out the remaining reserves for that well, you get a very dramatically different curve than if you calculate the remaining reserves from that well after the installation of the submersible pump; is that not correct?

A. No, that's not correct.

Q. You don't see after the submersible pump a higher curve to take that production curve on up than you do before you installed the pump?

A. It has a higher decline rate afterwards, showing its acceleration.

Q. Have you calculated those, taken those decline curves on out?

A. Yes.

Q. And you don't see any increase whatsoever?

A. No.

Q. Any competent engineer could take this and estimate for themselves the rate of decline, could they not?

A. Yes, you could come up with several different, but --

Q. Several different engineers might reach several different conclusions?

A. Right.

Q. But your conclusion is, no increase?

A. Right.

Q. Okay. I believe you testified that the A 1 has been shut in since the June hearing?

A. It was shut in, in November, and it -- I think they've turned it on a couple times for, you know, like two days in December and maybe two days in January, as sort of an experiment to see if it would make any oil.

Q. Was it your testimony that you had to shut that well in because of the increased production rate from the Enserch Lambirth A Number 1?

A. It was my testimony, I believe, that it could have caused us to shut it in --

Q. Didn't you --

A. -- earlier than we have.

Q. And didn't you -- Excuse me.

Didn't you testify in June that the well was at its economic limit, only producing until there was a pump failure?

A. Yes.

Q. If we look at the production curve on the Lambirth A Number 2, Exhibit Number 11 --

A. Okay.

Q. -- same well, and again you installed the submersible pump in February of 1992?

A. That is correct.

Q. Since that time you have seen high water cuts; is that right? Water coning?
A. I don't believe we've seen any water coning.
Q. You've seen water in the well?
A. It's making water, yes.
Q. It was your conclusion it was from a side water drive?
A. Primarily.
Q. This is the well you're pulling four times as hard as the Enserch well?
A. No, I think the -- We're not pulling it four times as hard, no.
Q. You're pulling it substantially harder, though, you've got a greater drawdown in this well than the Enserch well, we've just established that --
A. We have a greater drawdown, but it's -- I don't think it's that great.
Q. And because of the greater drawdown, you're pulling harder on the reservoir than the offsetting well?
A. Right.
Q. And it's possible that you could be pulling some water in with it because of the greater drawdown?
A. We're pulling in -- Yes, we're making more fluid.
Q. Now, I want to be sure I understood something that I discussed a few moments ago with Mr. Balke. I think

his basic testimony was that we have -- are seeing, because of high permeabilities, high drawdowns over big areas. Was that what you understood his testimony to be?

A. No.

Q. Okay. Well, let me just be sure I understand this.

Isn't it fair to say that in a reservoir of this nature, when we are looking at pressure drawdowns, generally speaking, the higher the permeability, the lower the pressure drawdown?

A. For a given rate of fluid withdrawal, right.

MR. CARR: That's all I have, thank you.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Commissioner Weiss?

I'm sorry, did you want to --

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: I didn't think so.

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. I'm confused about premature water breakthrough. These wells look like they all had premature water breakthrough back in the 1980s; is that right?

A. With the exception of the Lambirth A Number 3 and the Enserch Lambirth Number 1.

Q. And then you commented -- I sort of got this. And then let's just pick one of these. Your A 2 or A 3, how would bottom water versus edge water drive -- how would the performance here vary?

A. The -- Well, if you take a comparison between two wells, the Lambirth A Number 1 and the Lambirth A Number 2, one being ten feet higher than the other, the water cut should be higher in the lower well, and it's the reverse.

Q. Wouldn't vertical permeability enter into that?

A. I think vertical permeability is part of it, yes, is what causes the edge water drive, vertical permeability being lower than the horizontal.

Q. We don't know that, though, do we?

A. Well, I think if you -- I think that's what's going to cause the edge water drive.

Q. But given the fact that we don't know whether the vertical permeability is any different than the horizontal, I thought I heard --

A. Well, if you start off, if you think you have edge water drive, that's the only way I can explain edge water drive, is the vertical permeability is lower than the horizontal permeability.

Q. Okay. So the premise is that there's edge water drive, therefore --

A. Right.

Q. -- there's very little vertical permeability?
A. Or -- Just lower than the horizontal.
Q. Oh, and then one other thing. Does an increase in the oil cut mean increased recovery efficiency to you?
A. Not always.
COMMISSIONER WEISS: No more questions, thank you.
CHAIRMAN LEMAY: Commissioner Carlson?

EXAMINATION

BY COMMISSIONER CARLSON:
Q. What's the current allowable for the pool?
A. 267 barrels of oil a day.
Q. And you could live with that?
A. Actually, we'd like to have it reduced to 150, which is the maximum our well could make.
Q. But nobody's been able to make the allowable for many years until the Enserch Number 1 installed a submersible pump; is that correct?
A. Right.
Q. I'm looking at your Exhibit Number 11. I guess the difference between -- Well, you tell me what the difference is between your Exhibit Number 9 and your Number 11.
A. The blue scale? Well, the black scale is the same; both are oil.

Q. Uh-huh.

A. In Number 9 we're plotting in the blue water-oil ratio, and on Exhibit Number 11 the water -- it's just -- it's the water production in barrels per day.

And the red scale on the Number 11 is GOR, and the red scale on Number 9 is water --

Q. Right.

A. -- in barrels per day.

Q. And you don't think there's a marked increase in production after the submersible pump was installed?

A. Oh, I agree that, yeah, the oil has definitely gone up. But we think we're just accelerating the reserves.

Q. You said the decline rate has increased; isn't that what you said?

A. Yes. If you look previous to the submersible pump -- and you know, I know the production is quite erratic --

Q. Uh-huh.

A. -- but it's -- you know, varies, you know, varies slightly declining. But then you do see a pretty significant decline after the sub is installed.

Q. You're talking about, say -- What is that? The latter half of 1994, something in there?

A. Phillips put a larger submersible pump on the

Lambirth A Number 2, again in late 1994. That's what causes the oil production to go up again there. We put a bigger submersible pump in our well again then.

I probably should have marked that one on there too.

COMMISSIONER CARLSON: I think that's all I have.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Just one question. Do you think that the installation of a submersible pump on the Lambirth Number 1 by Enserch has affected your production to date?

A. Yes.

Q. In what way?

A. It's probably drawn in water -- or -- moving the -- more water closer to us faster.

And I know that some of the plots maybe -- not indicate it as much, but I know that in the -- but the date is fairly erratic, and I think, you know, over a long period of time, you'll see a more -- the water-oil ratio going up, or our water cut going up even faster than it was before.

Q. Do you think that's a higher -- a greater significant factor than the fact that your own submersible pumps have been pulling down the reservoir significantly, or at least producing the pressure drawdown which, as I understand it, could bring in the edge water?

A. It's definitely going to bring in -- You know, it's a function of how much oil is coming out.

And us making more oil, yes, is going to bring it in faster.

And then Enserch pulling it out is going to make it come up faster. Both would contribute to it.

CHAIRMAN LEMAY: That's all the questions I have.

THE WITNESS: Okay.

CHAIRMAN LEMAY: Thank you.

MR. KELLAHIN: That completes my presentation of Mr. --

CHAIRMAN LEMAY: Do you want to sum it up, or shall we just go with this?

MR. KELLAHIN: I want a short summary, if I might.

CHAIRMAN LEMAY: Sure.

MR. CARR: He always does. But I get to go last when he does this to me.

CHAIRMAN LEMAY: Okay.

MR. KELLAHIN: Mr. Chairman, members of the Commission, I have something that troubles me considerably, and I want to share it with you.

I'm not going to sit here and pretend as a lawyer to explain to you technical people how to handle the geology or the engineering. But I will tell you something that I am an expert in, and that is my serious concern that this Applicant has disregarded and disobeyed an order of this Division.

There is a comprehensive policy in writing from the Director that Examiner orders are effective until replaced or modified by this Commission. It is known by all lawyers that practice before this agency.

I am concerned that this Applicant goes to the District and gets permission for a test allowable, contingent upon the results of the hearing, in which Supervisor Sexton told them that after the Order was entered they were going to have to come in and account for the overproduction.

If they didn't like the Examiner Order in November, there is a comprehensive system where you ask the Examiner Order to be stayed. They didn't do that, they didn't ask for it, they didn't even call Mr. Sexton.

What do they do? They produce and continue to produce, not at 500 barrels of oil a day, but at 600 barrels of oil a day. Where is the accountability for the disregard of the orders of this Division? I can't remember an example of an applicant ever doing this before.

Their explanation? We'll just shut in and make it up, it doesn't matter.

It does matter. It matters to Mr. Pickett and it matters to Mr. Balke. If their hypothesis is correct, that increased withdrawals are going to more quickly water out their well, shutting Enserch in now has lost us an opportunity for oil recovery in the Phillips well that we cannot achieve again. The point in time is gone. And to suggest that they can be accountable by shutting it in now after ignoring the rule for months misses the point.

And you're the experts in the technical area, but I'll tell you, I am seriously concerned that an Applicant can come and do this. Shame on them.

CHAIRMAN LEMAY: Mr. Carr, would you like to sum up?

MR. CARR: That was the summary?

MR. KELLAHIN: Yes, sir.

MR. CARR: Mr. LeMay, I would agree with Mr. Kellahin that we're not engineers and geologists. I would point out in response to what Mr. Kellahin said in closing that I'm also troubled, but I'm troubled by a lawyer whose expertise is in the law, who makes a closing based on nothing that's put in the record.

We didn't hear any concern expressed by the operators of the wells in the pool, we didn't go into the details of what was or was not communicated with Mr. Sexton, and I would entrust you to look at the file, entrust this to you, look at the letter, and the letter says that this allowable level is not established on a permanent basis, that we will shut in, and I would submit to you, we're in compliance.

But I think that in fact to wait until the game is over to raise this is nothing more than after the fact trying to attack an order and a proceeding on grounds that really were never raised before, and it's nothing but an effort to deflect your attention from what's really before you.

I would point out that one time at a presentation when you and I were both on the panel, Chairman LeMay, I got in trouble with you and others for asking what was wrong with having the best well in the pool. Today I'm before you with people who have just that, who've been trying to figure out what to do with it. And we have come before you with a technical presentation that we trust you to evaluate and enter an order on the merits.

We have looked at the reservoir, we have shown you we have a fractured reservoir, we have what is basically a water-drive reservoir, a bottom water drive, Phillips says with some edge water impact. We have at this point in time, we believe, no oil-water contact because in fact the reservoir is virtually watered out, at least the fracture system.

We have differing opinions on what's going on in the reservoir. I would direct your attention to Phillips' Exhibit 5, and I trust you to determine whether or not that's an accurate depiction of what's occurring when you have the well that is on the extreme right of the exhibit drawing down the reservoir, putting pressure on the aquifer at four times the rate of the other well.

I will trust you to tell and decide whether or not this is an accurate depiction of a predominantly bottom water drive reservoir with an edge water drive component, and if that blue line that they have placed on this exhibit in fact shows how water would be migrating up into the wells. It totally disregards the bottom water drive component of this whole problem, this whole question we're wrestling with.

We've come before you today, we've presented the history of the Lambirth Number 1, we've given you an SPE paper and we've shown you that when we went out and applied this technology to this well we got the very, very results that, according to this paper, we should have expected. We've achieved exactly what they said we would, and we have a well capable of producing in excess of 500 barrels of oil a day, and that's why we need the higher allowable. And we have told you that if we don't get it, we're not going to defer but we think we will lose half a million barrels of oil.

Now, Phillips has a different view. Phillips comes in and they take Exhibit Number 9, and they say, We see no -- you'll have to not honor my doodling on it -- but they say, We see no impact, no benefit from high volume lift. Mr. Pickett can look at this exhibit and he can plot out remaining reserves, and he sees no difference.

But you see, that's why we come to a technical Commission; you can do that too. And I submit to you, when you plot the decline that that well was experiencing prior to the installation of high-volume lift, you're going to have a curve that is far below the curve that you will be able to plot after high-volume lift was installed.

And I would also submit that if you honor this data, in fact you will see that the curve is somewhat flatter, not sharper, after high-volume lift was installed. We see it, Phillips does not. But the fact is, in the final analysis, what's important is what you can see. And we submit that -- and trust you to look at this and determine whether or not in fact high-volume lift is working in the reservoir.

The question of correlative rights is a difficult one. We come before you, we argue waste, they argue correlative rights. But we have attempted to show exactly what is happening.

Now, we admit that the kind of data and information we use, the input factors need to be adjusted and that there are shortcomings, comparing the drawdown in their well with the drawdown in ours. But we have testified that the conclusion is the same, and that is, it isn't that we are going to be gaining an advantage on them, but they will maintain, albeit to a lesser extent, the advantage that they have enjoyed on us.

And it's not a question of ultimate recovery from the well; it's what they are taking now, where that pressure no-flow line happens to fall. And when you look at the record and you look at the data, I think you can clearly see that boundary falls on the Enserch tract.

The case is over, the record is before you. We believe we have shown that if you grant the Application there will be no negative impact on the correlative rights of Phillips, that the correlative rights, the opportunity afforded to Enserch to produce the reserves remaining in the matrix, those will be impaired.

We further believe that the evidence is clear, not only from what we have presented but from the Phillips Exhibit Number 9, that high-volume lift works, and by employing it in this reservoir we can recover a half a million additional barrels of oil, oil that otherwise will be lost.

CHAIRMAN LEMAY: Thank you, gentlemen, thank you for your presentations.

We'll take the case under advisement.

(Thereupon, these proceedings were concluded at 12:36 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 was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

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

WITNESS MY HAND AND SEAL March 4th, 1995.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

CASE NOS. 10,994, 11,579

CONTINUED CASES

TRANSCRIPT OF PROCEEDINGS

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

January 16th, 1997

Santa Fe, New Mexico

These matters came on for hearing before the Oil Conservation Commission, WILLIAM J. LEMAY, Chairman, on Thursday, January 16th, 1997, 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.

* * *

WHEREUPON, the following proceedings were had at 9:02 a.m.:

CHAIRMAN LEMAY: Good morning. If you haven't guessed, this is the Oil Conservation Commission. My name is Bill LeMay, Chairman of the Commission. To my left is Commissioner Bill Weiss, to my right Commissioner Jami Bailey representing the Commissioner of Public Lands, State of New Mexico. Lyn Hebert is our attorney, Florence [*sic*] Davidson keeps us in line and does everything for all of us.

So with that, I'd like to begin with Case Number 10,994, which is the Application of Phillips Petroleum to reopen *de novo* Case Number 10,994, Roosevelt County, New Mexico.

I understand there's a motion, Mr. Kellahin?

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of Phillips Petroleum Company.

Mr. Carr is counsel for Enserch, and he and I have agreed to ask permission to continue that matter until the next docket on February 16th, I think it is.

CHAIRMAN LEMAY: 13th.

MR. KELLAHIN: 13th.

CHAIRMAN LEMAY: Thank you. It's always a great day in the life of the Commission when Mr. Kellahin and Mr.

Carr concur on anything, so we shall certainly take that one and continue it until the 13th.

* * *

CHAIRMAN LEMAY: Now call Case Number 11,579, which is the Application of Pogo Producing Company for a pressure maintenance project, Lea County, New Mexico.

I understand that case was to be continued to the April 10th Commission hearing. Is there anyone representing those companies? Any objection to that continuance?

If not, Case 11,579 will be continued to the April 10th hearing.

* * *

CHAIRMAN LEMAY: We have some minutes of the previous meeting. Is there a motion to accept these minutes?

COMMISSIONER BAILEY: I move to accept the minutes.

CHAIRMAN LEMAY: Second?

COMMISSIONER WEISS: I second.

CHAIRMAN LEMAY: Thank you, the minutes will be accepted and placed into the record.

* * *

CHAIRMAN LEMAY: Just a little business before we get into the cases.

The Commission is considering holding their either April or May meeting in Roswell, so we're going to take our show on the road. And we're not sure of the -- My fellow Commissioners have to check their calendar as to availability. It certainly wouldn't take more than one day if we were down there, so...

I think April is the preferred date, and if we can do it, we'll do it. If not, May. Is there any comment on that, plus or minus?

I see Mr. Carr shaking his head. He might not even have a case, so it's not --

MR. CARR: We follow you wherever you go.

MR. KELLAHIN: He usually doesn't have a case, Mr. Chairman, and we'll go wherever you take us.

CHAIRMAN LEMAY: Okay, that will be our plan, and certainly in February we will give you our firm dates on that.

* * *

CHAIRMAN LEMAY: The other thing is, just point of information, don't forget the February 13th hearing is our Industry/Public Speaks-Commission Listens, so please go to your clients and tell them if they have an agenda, if they're dissatisfied or they're satisfied or whatever comments they have, please bring those before us because it's their opportunity, certainly, to do so at that time.

Also, of course, it's the proration hearing, which used to be a rather involved one, and now those things have gone pretty quick.

So we will get a schedule out in the docket and entertain any suggestions for change on the proration schedule. That's for February.

* * *

(Thereupon, these proceedings were concluded at 9:05 a.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 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 January 18th, 1997.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998

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 ENSERCH EXPLORATION, INC.

CASE NO. 10,994

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

BEFORE: WILLIAM J. LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
GARY CARLSON, COMMISSIONER

RECEIVED

MAR 6 1995

Oil Conservation Division

February 24th, 1995

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on Friday, February 24th, 1995, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

February 24th, 1995
Commission Hearing
CASE NO. 10,994

(Continued...)

PHILLIPS WITNESSES:

* * *

E X H I B I T S

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* * *

A P P E A R A N C E S

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* * *

WHEREUPON, the following proceedings were had at 9:00 a.m.:

CHAIRMAN LEMAY: Good morning, this is the Oil Conservation Division [*sic*], and we're continuing our hearing agenda from yesterday, and we shall now call Case Number 10,994.

MR. CARROLL: Application of Enserch Exploration, Inc., for the assignment of a special depth bracket oil allowable, Roosevelt County, New Mexico.

CHAIRMAN LEMAY: Appearances in the case?

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

We represent Enserch Exploration, Inc., and I have three witnesses.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

MR. KELLAHIN: Mr. Chairman, members of the Commission, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing today on behalf of Phillips Petroleum Company in opposition to the Applicant, and we have two witnesses to be sworn.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Would those about to give testimony stand, raise your right hand?

(Thereupon, the witnesses were sworn.)

CHAIRMAN LEMAY: Okay, let's start.

MR. CARR: I have a brief opening statement.

CHAIRMAN LEMAY: Mr. Carr?

MR. CARR: May it please the Commission, Enserch Exploration, Inc., is before you today seeking the adoption of a special depth bracket allowable of 500 barrels of oil per day for the South Peterson-Fusselman Pool in Roosevelt County. This pool was established in July of 1978 as a result of the discovery of oil in the Enserch Lambirth Number 1 well.

At the same time the pool was established, special pool rules were adopted on a temporary basis that were later made permanent, providing for 80-acre spacing.

Since that time, this pool has been developed basically by two operators, Enserch and Phillips. There is another operator in the pool, Bledsoe, but they are operating a well that isn't in the structural feature which is the subject of today's hearing.

These two operators have developed the pool on a checkerboard pattern. As we will show you, there is an active water drive in the field, and we now find ourselves at a point where there are approximately five wells that remain capable of producing from the South Peterson-Fusselman Pool.

This case is about the waste of oil. It's about how to maximize recovery of oil as we move to the last days of this reservoir's producing life.

Enserch will call Mr. George Faigle, a geologist. He will review for you the nature of the reservoir. He will show you that what we have here is a fractured reservoir with an active water drive. There is no oil-water contact in the reservoir, because the fracture system at this point in the reservoir's life is water-saturated.

As I mentioned a minute ago, there are only five wells still capable of producing. The Lambirth Number 1, the discovery well, was and remains the best well in the pool. And we will show you that it is the best well in the pool because of the quality of the rock from which it produces and also because it is structurally the highest well in the reservoir.

We will then call Ralph Telford, a petroleum engineer, and he will review the history of the Lambirth Number 1. He will show you that after years of reliable top-allowable production, the well in late 1993 watered out and Enserch was faced with what to do to try and return the well to producing status.

And they discovered an SPE paper that talked about the benefits that could be obtained from high-volume lift, increasing the rates of withdrawal in a reservoir of this nature. And this paper showed that if you would accelerate production you could pull water out of the fractures, and when you did that oil would flow from the matrix.

All the conditions in the paper fit the South Peterson-Fusselman Pool and the Lambirth Number 1 well, so Enserch attempted to employ this technology on the well. And we'll review with you what Enserch did: first rod pumps, then a submersible pump, then a larger submersible pump.

And we will show you that we achieved exactly what the SPE paper suggested we could achieve: a well that can produce over 500 barrels of oil a day with a reduced water cut.

The reason we're here is that if we are to continue to produce this well and obtain the benefits from high-volume lift, we have to have a higher allowable for the Lambirth Number 1.

If we don't get the higher allowable pursuant to directions from this Division, the well is overproduced and pursuant to your direction the well will have to be shut in. And if we do, we will show you that we may in fact lose the well.

And we can show you that if we are able to go forward, we should be able to produce approximately 456,000 barrels of oil that otherwise will be lost.

The case first came before the Division in June of last year, and Phillips appeared at that time in opposition to the Application, and the Application was denied.

Finding 10 of that order denying the Application stated that the Application was denied because at this time there is insufficient data available to assume that an increased allowable will prevent waste and protect correlative rights.

At that time the Examiner was correct. We put the well on pump in May, we came to hearing in June, and the presentation was based on analogies to other wells in the pool and basically limited data.

But since that time, we have nine months of additional data, and we can show you that HVL works in this reservoir, that it will prevent waste, that it will substantially increase the recovery of oil from this reservoir.

And then we will call Mark Burkett, a petroleum engineer, who will address the correlative rights aspects of this case, and he is going to show you that in fact there will be no adverse effect on any other operator in the pool, that correlative rights cannot be impaired.

And we will conclude by showing that if the Application is not granted, there is no correlative-rights issue, that almost 500,000 barrels of oil will be lost.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

This pool was developed based upon a farmout from Phillips Petroleum Company to Enserch, and the discovery well was drilled by Enserch back in 1978.

You'll see from the exhibits that there's an interesting pattern to the spacing units. They are 80-acre laydown spacing units, and it's checkerboarded.

As a result of the farmout, Phillips retained the alternative 80-acre tracts. And so when you look at the displays, you're going to see every other spacing unit, if you will, developed by one operator versus the other.

The reservoir rules were developed in 1978, and for some 17 years, now, this pool has been operated and depleted based upon an oil allowable of 267 barrels of oil a day.

There is a water component to the reservoir that's of significance to you. I have before me, and I will give you copies of, the order that Mr. Carr referred to. It was an Examiner case held in June of last year. And in November of 1994, then, on the third of November, the Division entered the order denying the Application of Enserch.

There were some fundamental issues of difference between the parties back in June. Those fundamental differences continue today. The additional information developed since the last hearing does not change the conclusions.

Despite the contentions of Mr. Carr, this is not a waste case; it is our evidence and our expert opinion from our witnesses' belief that this is strictly a correlative-rights case.

You will see when you look at the displays from our witnesses that the Enserch Lambirth Number 1 well does in fact enjoy a significant advantage over the closest well operated by Phillips.

The Phillips well is the Lambirth 2 A well. The Enserch well is the Enserch Lambirth 1 well. Both operators have used Lambirth in the naming of the wells. Those are the two wells that you will see, and we will talk about the most.

The advantage to Enserch is that they are 38 feet higher in their perforations in the top of the reservoir, and they have the opportunity to continue to produce their well so that it will drain the downstructure Phillips well.

And if you increase the oil allowable, you simply increase the opportunity for Enserch to take from Phillips Phillips' share of the remaining oil before Phillips has a chance to produce it.

It is our contention that after 17 years, we see no reason to change the rules. We are well aware of the SPE paper. We have studied that SPE paper in detail, and our witnesses come to different conclusions than Mr. Carr.

We believe this is a correlative-rights case because it's simply one operator utilizing a proposed increase in oil withdrawals to take advantage of the downstructure operator.

It will be our testimony that this is not a waste case, that the increased rates of oil production in the Enserch well don't result in increased ultimate pool oil recovery. The increased recoveries attributable to Enserch, our proof will show, are simply draining oil from us that we would otherwise produce. The dispute then is the dispute now. We believe none of the new information changes any of the results that Mr. Stogner entered when he decided this case back in November of 1994.

We believe at the conclusion of this hearing that we hope you will agree with us that the correlative rights of Phillips are impaired if you grant this Application, and we would ask that you affirm the Examiner order and deny the request of Enserch.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Mr. Carr, you may proceed.

MR. CARR: At this time, if it please the Commission, we would call Mr. George Faigle.

GEORGE FAIGLE,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?
A. George Faigle.
Q. Where do you reside?
A. Midland, Texas.
Q. By whom are you employed?
A. Enserch Exploration.
Q. And what is your current position with Enserch?
A. Development geologist.
Q. Mr. Faigle, have you previously testified before the Oil Conservation Commission?
A. Yes.
Q. At the time of that prior testimony, were your credentials as an expert in petroleum geology accepted and made a matter of record?
A. Yes.
Q. Are you familiar with the Application filed in this case on behalf of Enserch?
A. Yes.

Q. Are you familiar with the rules for the South Peterson-Fusselman Pool and the wells located therein?

A. Yes.

Q. Could you briefly summarize for the Commission what Enserch seeks with this Application?

A. Enserch seeks amendment of the special pool rules and regulations for the South Peterson-Fusselman Pool to provide for a special depth bracket allowable of 500 barrels of oil per day.

Q. Initially could you summarize for the Commission the current rules that govern development in this pool?

A. Eighty-acre spacing, designated well location requirements being within 150 feet of the center of the quarter quarter section.

Q. Now, those are the special pool rules; is that correct?

A. Yes.

Q. And then what are the other statewide rules that would come into play?

A. Okay, the statewide rules are depth bracket allowable of 267 barrels of oil per day.

Q. For an 80-acre tract?

A. For an 80-acre tract.

Q. And what is the gas-oil ratio?

A. 2000 to 1.

Q. And using these figures, what would the resulting casinghead gas allowable be for the pool?

A. 534 MCF per day.

Q. Let's go to Exhibit Number 1, and I'd ask you to identify that for the Commission.

A. Exhibit Number 1 is a small-scale orientation plat which shows the location of the South Peterson-Fusselman Pool as indicated by the green dot.

Q. And this is just -- generally shows where it is located in regard to other reservoirs in eastern New Mexico?

A. Yes.

Q. Let's go to Exhibit Number 2. Would you identify and review that?

A. Exhibit 2 is a large-scale area map showing the Fusselman producers in red dots and the pool operators, being Enserch, Phillips and Bledsoe.

Note that the Phillips 1 A is shut in at this time and that the Enserch Number 3 Lambirth Fusselman production is commingled with the Pennsylvanian production as of May of 1994. It also shows the completion dates of surrounding wells and the Enserch lease position.

Q. And the five wells in the center of the exhibit are basically the five wells that still do produce from the Fusselman in the area?

A. Yes, that's correct.

Q. And the arrow indicates the Lambirth Number 1?

A. Yes.

Q. Could you review the -- just generally, the characteristics of that well?

A. Okay.

Q. It is the best well in the pool, is it not, Mr. Faigle?

A. Yes, it's the highest well in the pool, and it's the best well in the pool.

Q. Okay.

A. It's indicated by the red arrow, as we stated previously.

Q. All right. Let's go to Exhibit Number 3. Will you identify that, please?

A. Okay, Exhibit Number 3 is a structure map on the lower paleozoic carbonate, which is the Fusselman in this area. It was prepared from well control.

It shows the five Fusselman wells left in this area. It also shows the Bledsoe well in Section 10; that's in the lower left-hand corner. It's also a Fusselman producer, which is interpreted to be on a separate structural closure.

The structural position of the producing wells in this pool shows the Number 1 Lambirth to be the structurally highest well in the pool.

Q. All right, let's now go to Exhibit Number 4. Would you identify that, please?

A. Exhibit 4 is a type log illustrating the Fusselman Pool. It was -- It is the log of the Number 1 Lambirth. It shows the area stratigraphic section being Pennsylvanian, on top of Fusselman, on top of granite, and it also shows the perforated interval in the Number 1 Lambirth.

Q. Could you generally describe for the Commission the characteristics of the Fusselman formation in this area?

A. Lithologywise, the Fusselman is dolomite, white to light gray through light tan, finely to coarsely crystalline to sucrosic. In the Number 1 Lambirth it was 178 feet thick, and the reservoir was encountered 60 feet into the Fusselman.

Porosities are in the range of 20 percent. The porosity is a bimodal system consisting of fractures and intercrystalline matrix porosity.

Permeabilities are in the range -- the 500-millidarcy range.

This is a water-drive reservoir. The trap is basically a structural accumulation of oil, formed at an angular unconformity where the Fusselman subcrops against the Penn.

Q. Now, Mr. Faigle, you prepared a cross-section of the wells in the pool?

A. Yes, sir.

Q. Let's go to Enserch Exhibit Number 5 and review that cross-section for the Commission.

A. Okay, Exhibit 5 is a structural cross-section showing the structural position of the Number 1 Lambirth and the three offsetting Phillips wells. It also shows the perforated interval in each well.

Q. Those perforations are indicated in green?

A. In the green color.

Q. And what does this tell you?

A. It -- The cross-section or the perforations?

Q. The cross- -- The perforations.

A. That they vary slightly from well to well. The reservoir is found in different structural positions in different wells.

Q. Structurally, the Lambirth Number 1 is the highest well in the pool, is it not?

A. Yes.

Q. Does the cross-section show an oil-water contact?

A. No, because the Fusselman pool is essentially watered out, an oil-water contact is irrelevant at this time.

Q. Let's look at Exhibit Number 6, please. Could you identify that?

A. This is a diagram of the high-volume lift concept and a geologic interpretation of how the high-volume lift theory applies to the Number 1 Lambirth.

It shows the dual-porosity system, fractures in the matrix, it shows the original oil-water contact, it shows that the oil in the fractures has been produced and replaced by water; the field has watered out.

It shows incremental oil in the matrix porosity, some of which can be covered by high-volume lift production methods, the details of which will be discussed in the engineering section.

Q. Basically, Mr. Faigle, what geologic conclusions can you reach from your study of this pool?

A. The reservoir is a dolomite, which has a heterogeneous bimodal porosity system consisting of both fractures and intercrystalline matrix porosity.

The pool is a structural accumulation of oil with the Number 1 Lambirth the highest well in the pool.

The main reservoir has watered out.

Q. And this geological interpretation is going to be used as a basis for the Enserch engineering presentation; is that correct?

A. Yes.

Q. Were Exhibits 1 through 6 prepared by you?

A. Yes.

MR. CARR: At this time we would move the admission of Enserch Exhibits 1 through 6.

CHAIRMAN LEMAY: Without objection, Exhibits 1 through 6 will be admitted into evidence.

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

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Faigle, sir, if you'll turn with me to your Exhibit Number 3.

Did you bring with you, Mr. Faigle, a copy of the Exhibit 3 that you introduced before Examiner Stogner back in June of 1994?

A. No.

Q. Let me show you, Mr. Faigle, what was introduced at that hearing and sponsored by you as Exhibit Number 3 and ask you if you recognize this exhibit.

A. Yes.

Q. Is that a true and accurate copy of the exhibit that you introduced before Examiner Stogner back on June 23 of 1994?

A. Yes.

Q. On your Exhibit 3 from the Examiner hearing, Mr. Faigle, you scribed a red line around some of the wells in the pool that would include the Lambirth 1 and the Lambirth 2 A. Do you remember doing that, sir?

A. Repeat that, please.

Q. Yes, sir. On Exhibit 3 from the Examiner hearing, you had scribed a red line on that exhibit. I'm looking at the one from the Examiner hearing. You scribed a red line around some of the wells, including your Lambirth 1 and the Phillips Lambirth 2 A, did you not do that, sir?

A. And several other wells.

Q. Yes, sir. You did that; is that not correct?

A. It essentially outlined the five producing wells -- it encircled the five producing wells we see on Exhibit 3, which is presented in this hearing.

Q. All right, sir. And your testimony at that time is, that circle represented the remaining productive acreage at that point in time in the reservoir, did it not?

A. No.

Q. On page 12 of that transcript, Mr. Faigle, did Mr. Carr ask you and did you not answer Mr. Carr, saying, "Now..."

MR. CARR: Let's --

MR. KELLAHIN: It's page 12, Mr. Carr.

MR. CARR: Let me give the witness a copy.

MR. KELLAHIN: It's page 12.

MR. CARR: What line are you at?

MR. KELLAHIN: I'm starting at line number 9, Mr. Faigle.

THE WITNESS: Okay.

Q. (By Mr. Kellahin) Are you with me?

A. Okay.

Q. It says, "QUESTION: Now, the area that you have indicated with the circle on this Exhibit, that's not the pool boundaries but just the acreage which you estimate now still productive in the reservoir?

"ANSWER: That outlines the are" -- I think that's a typo; it should say "area" -- "of the productive wells..." Right?

A. Yes, that's what it says.

Q. All right. Was that scribed area intended to represent the productive acreage left in the reservoir at that time?

A. No, it was put on there to outline, to run a circle around the producing wells.

Q. All right. The exhibit you've introduced today is substantially different than the Exhibit 3 from the June hearing, is it not?

A. It's different. I don't agree with "substantially".

Q. All right. Why have you changed your display from the one introduced in June?

A. Re-evaluation of the data.

Q. Have you changed the top marker point at which you've contoured the structure?

A. Yes.

Q. Okay. Exhibit 3 from the June hearing is on the top of the Fusselman, as you identified it back at that prior hearing, is it not?

A. That's correct.

Q. All right. On Exhibit 3 for today's hearing, what have you used as the top on which you have then contoured the structure?

A. The lower paleozoic carbonate.

Q. All right, let's go to the type log that you're introduced today and have you show us the difference.

A. Now your question, Mr. Kellahin, was --

Q. Yes, sir, you have changed the point at which you have drawn the structure map; am I understanding that correctly?

A. I have made some changes to the contoured horizon.

Q. Yes, sir. I want to look at the type log and find out where to find on the type log the points you've used as the marker point to construct the new structure map.

A. It's the line between the words "base of Pennsylvanian" and "lower paleozoic carbonate" --

Q. All right.

A. -- is the current contoured horizon.

Q. If we're looking at the structure map from the June hearing, where on this type log would we find that point?

A. I'll have to make an assumption on that. I don't recall exactly. I would assume it was around 7800 feet drilling depth.

Q. All right. What's the basis for changing the point at which you've drawn the structure?

A. To alleviate some of the confusion it caused.

Q. All right. When we look at the Exhibit 3 today, can you identify for us what in your opinion was the original oil-water contact in the reservoir at a minus subsea depth?

A. The original oil-water contact was in the vicinity of minus 3450 to minus 3440.

Q. All right, sir. Let me take a copy of your Exhibit 5 from today's hearing, which is the cross-section that you presented. I'm going to show you my copy, if I may. If I might lay this in front of you, Mr. Faigle. If you'll help me find --

A. 3450.

MR. KELLAHIN: If you'll help me find on my copy of your cross-section the point, minus 3450, that represents the original oil-water contact in the reservoir, I want to scribe a red line to show where that original oil-water contact was, all right?

All right, sir. Thank you, Mr. Faigle.

MR. KELLAHIN: Mr. Chairman, at my request Mr. Faigle has marked my copy of the log at the point with a pencil on each log where he has identified the original oil-water contact, and so that you'll be able to see that I'm going to draw a red line that connects those points so that there's a visual reference.

Q. (By Mr. Kellahin) When we look at the cross-section, my copy, I've put on the easel, just so that we could look at the same Exhibit at the same time, Mr. Faigle, when we're looking at that cross-section and find the Enserch Number 1 Lambirth well, the top perforation in the Enserch well is at a subsea depth of what, sir?

A. Minus 3380.

Q. And does that top perforation represent, in your opinion, the top of the original oil within the Fusselman reservoir?

A. It could be interpreted to mean that.

Q. So if we were to perforate higher in your well, we're not going to get any more oil production in the Fusselman?

A. I can't be sure enough to say that. There might be some minor amounts producible in the tighter parts of the reservoir.

Q. All right. When we go over to the Phillips 2 A Lambirth well, which is the first well on the left side of the cross-section, what is the top perforation in their well in a subsea depth?

A. Minus 3418.

Q. All right. The advantage in terms of that relationship is about 38 feet in preference to the Enserch well, is it not?

A. Correct.

Q. When we look at the cartoon, the Exhibit 6, the schematic illustration of -- that you're depicting, you have concluded that at this point in the depletion of the reservoir, that the fractures have watered out?

A. Yes.

Q. All right. With the original oil-water contact as we've described it on the cross-section, describe for us geologically how you believe that water to have moved so that now all the fractures are filled with water.

A. A water table will usually -- A bottom-drive water table will usually encroach from the bottom upward.

Q. Is it your opinion that this is a bottom-drive -- bottom water drive reservoir?

A. Yes, it is.

Q. All right, upon what do you base that opinion?

A. Literature.

Q. Do you have any field data with regards to this pool that supports that opinion?

A. This is more an engineering-type question, but I believe we do have some data that would indicate this.

Q. All right. You as a geologist don't see any geologic evidence to support whether or not it's a bottom water drive as opposed to an edge water drive?

A. I see some evidence, yes.

Q. As a geologist?

A. Yes.

Q. All right. If your concept of the bottom water drive is correct, then, would the water uniformly move vertically in the reservoir as the wells deplete the reservoir?

A. It would move -- generally -- It's not going to come up on a perfectly flat, horizontal plane. The water tables don't encroach that way. It would come up erratically. Not extremely erratically, but it's not going to come up as a horizontal plane, a flat, horizontal plane; it's going to come up gradually.

Q. All right. As that bottom water drive encroaches vertically into the oil column, if you will, what was the first well to experience increased water cuts that could be attributable to the migration vertically of that water?

A. Of the four wells on the cross-section?

Q. Yes, sir.

A. I would assume it would be the lowest structural position. The well with the lowest structural position would have the water cut first.

Q. All right. Describe for me your concept of the reservoir between this fracture system and what you've described as matrix oil.

And perhaps the Exhibit 6 is the display to look at. You have illustrated the reservoir to be a combination fracture and matrix porosity?

A. Yes.

Q. A dual-porosity system, if you will?

A. Bimodal porosity system.

Q. All right. Tell us why you have that belief.

A. Performance of the wells, literature, published literature.

Q. As the water drive moves up, it encroaches into the upper portion of the reservoir that originally had oil, it is your conclusion that that water has filled up the fracture system; is that not what this shows?

A. Yes.

Q. Okay. And at this point in the life of the reservoir, where, then, is the remaining oil left to be produced?

A. There may be some left in the fractures, small amounts that we're talking about, one percent or in that neighborhood. The oil remaining in the reservoir, we believe, is in the matrix porosity.

Q. Describe for us why you have that belief.

A. Because the production characteristics of the wells would indicate that the oil would be produced from the fractures first since they have the greatest permeability, and they would water out first.

Q. Mr. Carr mentioned that there were still five wells left in the pool that continue to produce. You've shown four on the cross-section. Where is the fifth?

And perhaps we could look at a locator map. Exhibit 3 serves that purpose, I believe, if you'll look at Exhibit 3.

A. The Fusselman producer not on the cross-section is the Enserch Number 3 Lambirth.

Q. All right, it's the northeast offset to the well with the red arrow?

A. Yes.

Q. Why has that well been excluded from the cross-section?

A. It was my understanding of the problem, was between the Enserch Number 1 Lambirth and the offsetting Phillips wells.

Q. What is the status of the Enserch Lambirth 3 well, the well that's excluded from the cross-section?

A. The Number 3 is producing commingled from the Pennsylvanian and the Fusselman.

Q. Is it still producing oil, then, from the Fusselman?

A. We have to assume so. Being commingled, there's no way I can qualify or disqualify which zone is producing the oil.

Q. When was that well commingled, Mr. Faigle, approximately?

A. May, 1994.

Q. At the time it was commingled, was it open in the Fusselman?

A. No, it was a Pennsylvanian producer that was recompleted commingled to Fusselman and the Pennsylvanian.

Q. All right. So you had Pennsylvanian gas production or oil?

A. Oil.

Q. Pennsylvanian oil production in the well, and then you went up and added the Fusselman?

A. We went down and --

Q. I'm sorry.

Q. -- recompleted in the Fusselman.

Q. All right.

A. The well was originally a Fusselman producer, low oil volumes, high water volumes, which was produced for a very short period of time in the Fusselman and then recompleted to the Penn.

Q. At the time that the Fusselman was originally abandoned in that well, what kind of oil-water rate did you have?

A. I don't know.

Q. All right. Do you recall approximately when that took place?

A. No.

Q. At this point is it fair to assume that there's little if any contribution from the Fusselman in that wellbore? That's a --

A. No.

Q. We don't know?

A. No, I don't think it's fair to assume that there's little or no contribution from the Fusselman in that wellbore.

Q. At this point there's no way to retrieve the data from that well to determine whether or not there's any oil contribution from the Fusselman?

A. State that again, please.

Q. Because it's been commingled, there is no way to currently know what oil contribution is being made from the Fusselman in that well?

A. We know what it was capable of before the Fusselman was abandoned the first time, and we assume that when we went back there, we were in the neighborhood of those volumes.

Q. And what rate was that again, sir?

A. I do not know.

Q. All right. Can you quantify or define for me, Mr. Faigle, how you're using the term "watered out"?

A. When a well reaches water cuts of approximately 95 percent and also it's becoming marginally economic, it's costing more to dispose of water and lift than we can make a profit from the oil that the well produces, it's essentially -- it's economically watered out.

Q. I'm not sure I understood the answer. You gave me two criteria. A water cut of 95 percent?

A. It varies. It depends on the volumes you're lifting.

Q. All right. Separate that for a moment. You also gave me an economic criterion.

A. Yes.

Q. You could have an economic criterion that made a well unprofitable --

A. Yes.

Q. -- at less than 95-percent water cut, could you not?

A. Sure.

Q. All right. Which of those two criteria are the determining factor in your definition of "watered out"?

A. I would use them both.

Q. At what time in the productive life of the reservoir did the fracture system, in you opinion, become watered out?

A. Which well? It happened --

Q. Well, all wells, now, in your opinion, have watered out in the fracture system?

A. The fracture system has watered out.

Q. In all wells?

A. In all wells.

Q. At what point did that occur in your Enserch Lambirth 1 well?

A. I don't know. The engineering section may be able to help you with that answer.

Q. All right. Would you know the point in time where the fracture system in any of these wells watered out, by your definition?

A. It would depend on operating costs and things that -- on an individual well basis you'd have to look at it.

Q. Can you express an opinion as to when any of these wells watered out in the fracture system?

A. A particular date, no, that would have to be an engineering evaluation considering economics and volumes and...

Q. Was it your opinion before Examiner Stogner that the increasing oil allowable that you've requested was not going to be an advantage of Enserch over Phillips because you believe the rising oil-water contact was going to affect all wells approximately equally, because all of them had a similar relationship as to their bottom perforations?

A. State that again, please.

Q. Yes, sir. If you'll look at the transcript, maybe that's how to do this. Look at Exhibit -- the transcript, and if you'll turn to page 13 with me, if you'll look at line 18.

A. Page what? Thirteen?

Q. Yes, sir, line 18. Mr. Carr is asking you, "So in the Enserch well, the well that you're primarily concerned about, and the immediate offsetting Phillips well to the north, the bottom of the perforated interval is identical?

"ANSWER: Correct. Now, this -- Therefore a rising oil-water contact would affect both wells equally. There would be no advantage to either well."

Do you see that?

A. Yes.

Q. All right. Was it not your conclusion geologically at the Examiner hearing that as a result of the bottom water drive and the fact that the Enserch Number 1 well and the Phillips 2 A well had bottom perforations that were approximately at correlative intervals in the reservoir, that you could increase the oil allowable, and you would have no advantage?

A. I don't understand what you're --

Q. What part of my question do you not understand, sir?

A. Well, could you break it down into pieces? Maybe I can handle it better that way. I seem to be getting a complex question, and I don't know how to answer it.

Q. All right. You have reached the opinion that this is a bottom water drive reservoir, right?

A. Yes.

Q. All right. When you look at the perforations in the bottom of the Lambirth well for Phillips, the 1, if you look at the cross-section --

A. Yes.

Q. -- do you see that?

A. Yes.

Q. All right. That bottom perforation is in what relationship to the Enserch Number 1 well?

A. They have similar subsea depths at the bottom of the perforations in each of those two wells.

Q. All right. Because that is so, and because you concluded that this was a bottom water drive, you've also concluded, did you not, sir, that there would be no advantage to Enserch by increasing the oil rate, because the increased rate would simply affect both wells equally as the water moved vertically?

A. We were beyond that point in the -- where to position -- The reservoir was already watered out at that time. So at that time there would be no advantage, it was too late for an advantage. We were speaking historically about rising oil-water contacts. At the time of the hearing, the oil-water contact was essentially at the top of the reservoir by then, or very close to it.

Q. Okay.

A. The advantages you're looking for may have been historical. They weren't current.

Q. All right. Do you see any remaining oil column, then, in the matrix above the original oil-water contact?

A. Yes.

Q. Can you determine where that point is in the matrix?

A. I'll have to make an assumption that there's matrix oil available everywhere above the original oil-water contact if you can get it out.

Q. All right. Does not, then, Enserch continue to enjoy an advantage of some 38 feet in the perforations between you and Phillips as you compete for the remaining oil in the matrix?

A. There's no doubt about it, we have the highest structural well in the best reservoir, I can't dispute that.

MR. KELLAHIN: All right, sir.

Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Thank you.

MR. CARR: Mr. Chairman, I'd like to --

CHAIRMAN LEMAY: I'm sorry.

MR. CARR: -- and I'll be brief.

CHAIRMAN LEMAY: That's fine.

REDIRECT EXAMINATION

BY MR. CARR:

Q. Mr. Faigle, at the Examiner hearing there was some confusion about the zone or the interval that you used for constructing the structure map of this reservoir map; is that not true?

A. Yes.

Q. And so to correct that what you did was, you went and picked a marker that is the base of the Penn in a clearly definable interval; is that not correct?

A. Correct.

Q. Isn't that what caused the difference between the structure map that was offered in June and the structure map that is offered now?

A. Yes, it did.

Q. And by drawing a red line at the original oil-water contact in this reservoir, hasn't Mr. Kellahin in essence just taken your structure map, and it is a more refined example of what the schematic is designed to show?

A. Correct.

MR. CARR: That's all I have.

CHAIRMAN LEMAY: Thank you.

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. You said that it actually fractured the perm 500 millidarcies. Did you measure that, or is that an estimate?

A. That's a measured permeability from a well performance test on the Number 1 Lambirth.

Q. So this is, I think, perhaps more an engineering question, but the fractures were identified from the same test?

A. We assumed, I believe, that there were fractures. They're about the only thing that could give us a permeability of that magnitude after looking at the porosity on the logs.

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

CHAIRMAN LEMAY: Commissioner Carlson?

COMMISSIONER CARLSON: No questions.

CHAIRMAN LEMAY: I have no questions. Thank you.

MR. CARR: May it please the Commission, at this time we would call Mr. Ralph Telford.

RALPH B. TELFORD,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Ralph Telford.

Q. Where do you reside?

A. Midland, Texas.

Q. By whom are you employed and in what capacity?

A. Enserch Exploration as a petroleum engineer.

Q. Have you previously testified before the Commission?

A. Yes, I have.

Q. At the time of that prior testimony, were your credentials as a petroleum engineer accepted and made a matter of record?

A. Yes, they were.

Q. Does the geographic area of your responsibility with Enserch include the Southeast Peterson-Fusselman Pool area?

A. Yes, it does.

Q. Are you familiar with the wells completed and producing from that pool?

A. Yes, I am.

Q. Are you familiar with the Application filed in this case on behalf of Enserch?

A. Yes.

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

CHAIRMAN LEMAY: They're acceptable.

Q. (By Mr. Carr) Mr. Telford, could you review for the Commission what it is Enserch is asking the Commission to do in this matter?

A. We're looking for an assignment of a special depth bracket allowable for the South Peterson-Fusselman Pool of 500 barrels of oil per day to replace the current depth bracket allowable for said pool of 267 barrels of oil per day.

We want an assignment retroactive to June 1st, 1994, which is the date which Enserch's Application was filed. And if we're not approved, the well is overproduced and we'll have to shut it in.

Q. The reason for the retroactive request, that June 1st is the first day of the first month following the day the Application was filed?

A. Yes.

Q. Initially, Mr. Telford, could you just summarize the existing rules for the pool?

A. Pursuant to Order R-5771 as amended by Order 5771-A, special rules and regulations were adopted for this pool which provided for 80-acre spacing and designated well location requirements.

Statewide rules are 80-acre, depth bracket allowable of 267 barrels of oil per day, a 2000-to-1 GOR which resulted in a 534-MCF-per-day casinghead gas allowable.

Q. All right. Now, those were the rules that were in place in May of last year?

A. Yes.

Q. At that time you were experiencing problems with the Lambirth Number 1 in terms of maintaining its production levels?

A. Yes.

Q. And an Application was then filed with the Oil Conservation Division?

A. Yes.

Q. Could you refer to Exhibit Number 7 and then just very briefly review for the Commission the history of this particular case?

A. Okay, in July 17th, 1978, the pool was established and temporary pool rules were adopted providing for 80-acre spacing and proration units. In August of 1979 the pool rules were adopted on a permanent basis.

In May of 1994 we installed a submersible pump on the Lambirth 1. And May 9th of 1994, a special allowable authorized for the Oil Conservation in the Hobbs District, we received a letter from them.

And May 17th, 1994, Enserch filed Application for a special depth bracket allowable.

On June 23rd, 1994, Enserch appeared before the Commission, like we are today, to get the rules made permanent. We had a continuance till July 21st.

And on November 3rd the -- we received the Order

R-5771-B denying the Application of Enserch.

On November 8th, Enserch filed for the Application, for hearing *de novo*.

January 12th, the Oil Conservation Commission hearing was continued, at the request of Enserch. Phillips advised the Commission it had no objection to the continuance.

And February 24th, today, we are here to settle this whole thing.

Q. Now, Mr. Telford, identify what's been marked as Enserch Exhibit 8, please.

A. It is the Oil Conservation Division Order R-5771-B, dated November 3rd, 1994, which denied Enserch's Application.

Q. Now, this is the Examiner Order, and the Order in its findings sets forth the presentation of both the parties; is that correct?

A. That is correct.

Q. Could you go to Finding Number 10 on page 4 and just read that into the record, please?

A. It says, "At this time there is insufficient data available to assure that increased oil allowable for the South Peterson-Fusselman Pool will not result in the impairment of other operators' and mineral-interests' correlative rights in the pool and would not result in the prevention of waste."

Q. If we look at the case history, Exhibit Number 7, I believe you testified that you started experiencing the increased production rate from the Lambirth Number 1 in May?

A. That is correct.

Q. And it was on May the 9th that you approached the Oil Conservation Division concerning this matter?

A. Yes.

Q. And then the matter came for hearing on June the 23rd?

A. That is correct.

Q. It was on June the 23rd, was it not, that the actual evidence was presented in this matter?

A. Yes.

Q. So at that time you had less than two months' information on the well?f

A. That is correct, and we were also experiencing mechanical problems with the well at the time.

Q. At this point in time, has additional information been obtained that addresses the concerns expressed by Mr. Stogner in the Examiner Order?

A. Yes.

Q. Before we get into the actual information on the SPE paper and on the well performance, could you review what it is exactly you're requesting and why that request has to be made?

A. We're looking to increase the ultimate recoveries from the Lambirth Number 1. To do that, we must increase allowables from the pool.

The well currently produces in excess of the allowable, and special allowable will improve economics and increase this well's ultimate recovery. And this will also will not impair the rights of any other operator in the pool.

Q. Now, Mr. Burkett is going to be called to review that last point --

A. The correlative rights, yes.

Q. -- correlative rights?

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

A. This is SPE paper 7463. This paper was written in 1978 by Amoco, and basically the paper sets out a theory that we find applicable to the Lambirth Number 1.

The paper has empirical data from 55 wells. It shows an average increase of reserves of 350,000 barrels of oil. The parameters are applicable to these type of wells. The best candidates are in the Devonian reservoir. The reservoir is heterogeneous and has a water drive, and the wells are producing with less than a 95-percent water cut and greater than a 70-percent water cut.

Q. Now, do all of those parameters fit the South Peterson-Fusselman Pool and the Lambirth Number 1?

A. Yes, they do.

Q. Were you the individual that came across this SPE paper?

A. Yes.

Q. And when you saw that paper, were you the one who concluded that perhaps this type of high-volume lift would be something that could be tried on the Lambirth Number 1?

A. Yes.

Q. All right. Let's go back to Exhibit Number 6. It's up on the easel above the cross-section.

Basically, using this, just summarize what your understanding of the characteristics of this reservoir have to be.

A. Basically, what we have is a dual-porosity reservoir. You have the matrix and you have the fractures. And currently the fracture system is watered out and the remaining oil is in the matrix.

Q. Is that the kind of reservoir that was the subject of this SPE paper?

A. Yes, it is.

Q. All right, let's look at the Lambirth Number 1 well, and I would direct your attention to Enserch Exhibit

Number 10, the production history. Could you review that for the Commission?

A. Yes, the Lambirth 1 was the discovery well for the pool. Production started in 1978.

You'll notice the green curve is oil production, the red curve is gas production, the yellow curve is gas-oil ratio, the dark blue curve is water production, and the light blue curve is water cut.

You'll notice the well produced relatively flat till 1986 when the well started making water. The well was then pinched back to curtail this water production. This pinching back was continued until 1993 when the well essentially watered out and died.

Then a rod pump was installed, production increased to 60 barrels of oil per day and water cuts were in the 80- to 88-percent range.

In May of 1994 a submersible pump was installed.

Next, we need to go to exhibit --

Q. If we look at the exhibit, the gas-oil ratio is basically flat, is it not?

A. Flat, which is indicative of a water drive reservoir.

Q. And this is the -- not only the discovery well, but has been a top-allowable in the well --

A. Yes.

Q. -- well in the field?

A. It is the best well in the field.

Q. All right. Let's go now to Enserch Exhibit Number 11. Identify this, please.

A. Okay, what we have here is daily production for the Lambirth 1. It starts in December of 1993.

The dark green curve is oil production, the dark blue curve is water cut.

If you'll notice, in December until April the oil production was relatively flat, slightly declining. It's 60 barrels a day.

In May we put our first submersible in the well, denoted by the red line. Production then increased from 60 barrels a day to between 200 and 300 barrels a day. Also, if you'll notice, the water cut went from about 86 percent to 90 percent.

Later on, in August, we installed a larger submersible as denoted by the next red line. Production then increased to over 500 barrels of oil per day and water cut decreased from 90 percent to a low of 84 percent. And that's climbed to its current rate of between 86 and 87 percent.

Q. All right, Mr. Telford, when we look at Exhibit Number 10, the production history on the Lambirth Number 1, we have a well that basically fits the criteria in the SPE paper?

A. That is correct.

Q. And we've already established we have a reservoir that meets that criteria?

A. Uh-huh.

Q. Now, if we go to Exhibit Number 11, we can see what happened as you attempted to employ these high-volume lift techniques to the reservoir.

What does this production curve, Exhibit Number 11, tell you about the success of high-volume lift in this reservoir?

A. Okay, what I've done, if you'll notice the light dashed pink curve, that is a production decline shot for the rod pump. It also shows remaining reserves of 31,000 barrels of oil.

Next up, I've shot a decline from the smaller submersible. It showed a remaining reserves of 160,000 barrels of oil.

And finally, the dashed green curve shows remaining reserves of 487,000 barrels.

So incremental reserves over the rod pump is 456,000 barrels and 327,000 barrels over using the small submersible. And this is oil that would not be recovered by any other well in the pool unless we keep the large submersible in the well.

Q. So this Exhibit Number 11 shows that when you put the submersible pumps on the well, in fact you got the response that you were anticipating in accordance with the SPE paper?

A. Yes, we -- It shows larger recoveries and also the decreased water cuts.

Q. And basically what it shows when you then take the new production curve and plot it out, that you will recover ultimately almost 500,000 barrels of oil more with the large submersible pump in the well than you would have been able to with simply the rod pump?

A. That is correct.

Q. Now, Enserch obviously is recovering more oil from the Lambirth Number 1 than any other well in the pool?

A. That is correct.

Q. And that's a result of these recovery techniques?

A. Yes, that's also due to better structure and better quality rock and more oil underneath our tract.

Q. In your opinion, is it possible that this high-volume lift technique could be applied to other wells in the pool?

A. Yes.

Q. In fact, has it been?

A. Yes, it has.

Q. In what wells?

A. The Lambirth 1 A and the 2 A.
Q. Have the -- comparable results been obtained in those other wells?
A. Not as good as the Lambirth 1 A.
Q. Do those other wells have comparable structure or rock quality when you compare them to the Lambirth Number 1?
A. No, they do not.
Q. All right. Let's go to what has been marked Enserch Exhibit Number 12. Could you identify and review that, please?
A. Basically what we have here is a list of wells that Enserch operates that have been lost to casing failures in the South Peterson area.
If you'll notice, there's twelve wells in the list. This represents 41 percent of the wells that we operate in the area.
Due to losing these wells we've lost reserves of 460,000 barrels of oil and 478 million cubic feet of gas.
Q. The Lambirth Number 8 has been lost since the hearing last June?
A. That is correct. That was one of the candidates that we were looking to apply the high-volume lift to.
Q. And when did that casing collapse occur, casing failure occur?

A. September of 1994.

Q. If we look at Exhibit Number 12, this simply shows that if you lose your well, you're unable to produce your reserves?

A. That is correct.

Q. If we look and relate that back to Exhibit Number 11, what that shows is that by employing high-volume lift you recover additional reserves that in fact are not going to be achieved but left in the ground?

A. That is correct.

Q. If you're able to employ high-volume lift in a timely fashion, you're going to get the benefit not only of the technique, but you're hopefully going to have a well that will enable you to recover these reserves?

A. Yes. I'd also like to point out that the Lambirth Number 1 is the oldest well in the pool.

Q. Mr. Telford, in your opinion will approval of this Application and the increase in the allowable permit Enserch to produce the Lambirth Number 1 in a fashion that will ultimately result in the prevention of waste of oil?

A. That is correct, yes.

Q. Will you be calling another witness, Mr. Burkett, to review the correlative-rights aspects of this Application?

A. Yes.

Q. Were Exhibits 7 through 12 prepared by you or compiled at your direction?

A. Yes, they were.

MR. CARR: At this time, may it please the Commission, we move the admission of Enserch Exhibits 7 through 12.

CHAIRMAN LEMAY: Without objection, Exhibits 7 through 12 will be admitted into the record.

MR. CARR: That concludes my direct examination of this witness.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Telford, if you'll find Exhibit 10 for me, perhaps we can use that to illustrate my questions for you, sir.

In terms of your chronology, when did you first put in the first pump that had the ability to produce sufficient fluids from your well so that you had the opportunity to produce oil in excess of the daily oil allowable of 267 barrels?

A. That would be May.

Q. That's the May of 1994 --

A. That's the small submersible.

Q. The highest rate of oil productivity on a daily basis that you were able to achieve with that submersible was what, sir?

A. That was slightly over 300, I believe. If I can look --

Q. I believe your --

A. About 350.

Q. All right. Somewhere in the 330 to 350 range, I believe, is what we talked about last June.

A. That is correct. Since then we've installed the larger submersible.

Q. All right. From the point of time that you exceeded the allowable, the 267, up until the date of the hearing, there's a reference here to an authorization by the Hobbs OCD --

A. Yes.

Q. -- to conduct a test, if you will --

A. That is correct.

Q. -- and exceed the oil allowable. All right? Is that not correct?

A. That is correct.

Q. And you introduced a letter from Mr. Sexton back in June describing for you the terms and conditions for that test; is that not correct?

A. That is correct.

Q. I show you a copy of what was introduced as Enserch Exhibit 11 to that Examiner hearing.

What were the conditions imposed upon Enserch for producing in excess of the daily oil allowable?

A. That we file for a hearing within 20 days.

Q. All right, sir, and you did that?

A. Yes, we did.

Q. And the last paragraph of that letter says that after the order is entered for that hearing, what then will happen?

A. The well will have to be curtailed and the overage made up.

Q. All right. From the hearing, July -- I'm sorry, June 23rd, that was our evidentiary hearing? --

A. Yes.

Q. -- to the date of the Order, November 3rd of 1994, what did you do in terms of producing that well?

A. We installed the larger submersible pump and gathered more data.

Q. Okay, the larger submersible pump was installed approximately when, sir?

A. In August.

Q. Do you have a date in August?

A. The exact date? Not with me.

Q. All right, sir. In August of 1994, you went to a larger submersible with what result?

A. With what result? Increased oil recoveries and decreased water cut.

Q. Give us a general range of the oil rate on a daily basis that you were producing.

A. Close to 600 barrels of oil a day.

Q. All right. How long were you able to sustain producing at 600 barrels of oil a day?

A. Not very long.

Q. All right. You have production records on a daily basis --

A. Yes.

Q. -- that would show us exactly how this was done?

A. Exhibit 11 shows that.

Q. We can pull it off of Exhibit 11?

A. Yes.

Q. All right. On November 3rd, then, what then did you do with the well? After you got the Examiner order? I assume you got it reasonably at some period of time after November the 3rd.

A. We received it, I believe, on the 8th.

Q. All right. What then did you do?

A. We filed for a hearing *de novo*.

Q. All right. What did you do in terms of producing the well?

A. We kept producing the well.
Q. At what rate, sir?
A. At its current rate, 500 barrels a day.
Q. Okay. Did you go back to Mr. Sexton and ask for additional authority from him to produce in excess of what the Examiner had required you to do as a result of the November Order?
A. No, we did not. We assumed that since the case was still pending we could still produce the well.
Q. Is there anything in Mr. Sexton's letter that tells you you can do that?
A. No, there's not. But we have every intention of shutting the well in if we lose today.
Q. From November 8th to the current period, can you tell us what -- Let me ask you a different way.
What as of today is the current total overproduction of oil on the well?
A. As of November, it's approximately three months' worth of production. We'd have to shut in the well for three months.
Q. As of November --
A. As of November 1st, from November 1st to now, three months' production.
Q. Can you -- I don't know if you have it with you now, but you could calculate for us --

A. Actually, I may have it with me right here.

Q. All right, sir, let's get an actual number.

A. Actually, I've got it over there. Can I get it over here?

Q. Yes, sir.

A. The actual number as of November 1st through January is 25,081 barrels.

Q. From November 1st to when, sir?

A. Through January.

Q. Through January of 1995?

A. Through January of 1995.

Q. All right. Prior to November 1st, what is the overproduction?

A. I don't have those numbers handy.

Q. So the 25,000 is not a cumulative total --

A. No, it is not.

Q. -- of overproduction?

You keep production records on a daily basis, though, so should the Commission require it, you can tell the Commission exactly how much total overproduction is attributable to this well at any given point in time?

A. That is correct, that will be no problem.

Q. When we look at the SPE paper, the criteria, if you will, for having an opportunity to achieve increased oil rate with a high-volume lift system within the parameters of that paper was a water cut between 70 percent and approximately 95 percent, if I remember the paper correctly?

A. That is correct.

Q. All right. Did I hear you correctly in response to Mr. Carr that that technique would have or could have been available to any of the wells in this South Peterson-Fusselman Pool if they were within that range?

A. That is correct, if they were within that range and they had the correct reservoir characteristics.

Q. All right. Does the paper describe any additional criteria in terms of reservoir characteristics?

A. Just a heterogeneous reservoir, preferably Devonian.

Q. Does it give you any preference or criteria to structural position?

A. I do not believe so, no.

Q. Does the paper qualify or alert the reader to the issue of premature water breakthrough?

A. Yes, it does.

Q. And what does it say about that issue?

A. Well, let me read it to you.

Q. All right.

A. It says, if you'll look on page 4 of the paper, "Concern over premature water breakthrough and reduced ultimate recovery from application of high-volume lift is unsubstantiated in most heterogeneous, west Texas carbonate, oil-wet, natural waterdrive reservoirs."

Q. Did the paper discuss or attempt to study whether or not the application of this technique would result in increased ultimate recovery for the pool?

A. No, it did not.

Q. It was talking about the opportunity for an individual well to increase its ultimate recovery?

A. Yes, but this could be applied to other wells, not just one well.

Q. I understand, but the paper was making no argument in terms of total reservoir recoveries in a waste context?

A. No, it did not.

MR. KELLAHIN: All right. Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Thank you.

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Is the well pumped off now?

A. No, sir, it is not. The fluid level is 1320 feet from the surface. I wish we could pump it off.

Q. So the other wells are still flowing, I take it, that are out there?

A. They're on submersible as well. Well, the A 2 is on submersible; our Number 3 is on rod pump.

Q. So they're all on artificial lift?

A. Yes.

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

CHAIRMAN LEMAY: Commissioner Carlson?

COMMISSIONER CARLSON: No questions.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. One question I have here on your Exhibit Number 11. That's the --

A. Daily production plot?

Q. Yeah, that's --

A. Okay.

Q. -- the detailed one. Was that well shut in, it looked like, through the month of April, 1994?

A. Yes, it was. We were waiting on electricity.

Q. But when you brought it back on, there was no problem bringing it back on after having it shut in that period of time?

A. No, there was not.

CHAIRMAN LEMAY: Thank you, that's all I have.

Do you want to take a break now, or -- Do you have one more witness?

MR. CARR: I have one more witness.

CHAIRMAN LEMAY: Okay, let's go with him.

MR. CARR: All right. At this time we would call Mr. Mark Burkett.

MARK BURKETT,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Mark Burkett.

Q. Where do you reside?

A. I reside in Midland, Texas.

Q. By whom are you employed?

A. Enserch Exploration.

Q. And what is your current position with Enserch?

A. I am the district petroleum engineer.

Q. Mr. Burkett, have you previously testified before this Commission?

A. Yes, sir, I have.

Q. At the time of that prior testimony, were your credentials as a petroleum engineer accepted and made a matter of record?

A. Yes, they were.

Q. Are you familiar with the Application filed in this case on behalf of Enserch?

A. Yes, sir.

Q. And are you familiar with the rules for the South Peterson-Fusselman Pool and the wells located therein?

A. Yes, sir.

Q. I'd like to direct your attention to what has been marked as Enserch Exhibit Number 13. Would you identify that and then review the information on this exhibit for the Commission?

A. Okay, Exhibit 13 is a -- as Mr. Telford testified earlier, this is a pressure profile, or a calculated pressure profile, of the pressure as a function of distance away from the wellbore for the Lambirth Number 1.

As you can see on the X axis, we have a distance from wellbore. It goes from zero to 1300 feet.

On the Y axis we have pressure, a wellbore pressure, from 2300 to 2550.

The green line is the static reservoir pressure that was determined from a pressure buildup test. The last pressure buildup test we conducted on the Lambirth Number 1 was 2518 p.s.i.

Our last fluid level that Mr. Telford referred to, 1320 feet, calculates to roughly a wellbore flowing pressure of 2318 pounds, which would be the intercept of the Y axis with the blue curve. The blue curve would represent pressure as you move away from the wellbore.

Now, this is a very simplified diagram; there were a lot of assumptions built into it. It's based on a very simple engineering calculation, Darcy's law. It assumes steady-state flow, it assumes an impotent-acting reservoir, only one well in the reservoir.

The KH or capacity was adjusted to take into account water and to take into account the actual data that we're seeing today, based on the fluid level. It assumes constant permeability and no skin.

This is a real basic model, but what it's showing is that most of the drawdown occurs in the first 150 feet.

It's also showing that we're only drawing down the wellbore 200 pounds, so we're just barely drawing on this reservoir. It's saying that we're unable to draw down the reservoir, and this is with the current 500-barrel-per-day production. So this is the current conditions, and it's basically saying that we're unable to draw down this reservoir even with the largest pump possible.

It's also showing it's a very prolific well, an extremely prolific well.

One other thing to point out is, as we get to the lease line, it's denoted by the dark line at about 660 feet. We see a pressure drawdown of about 31 p.s.i. at the lease line.

Q. All right, Mr. Burkett, let's take now this exhibit, put it aside and go to Exhibit Number 14.

Could you explain what you've done, how you've constructed Exhibit Number 14 and its relationship to the previous exhibit?

A. Okay, Exhibit 14 is really an extension of Exhibit 13. Again, you can see the blue line. On the left side of the page is the Lambirth Number 1. On the right side of the page would be the Lambirth A 2.

Again, the X axis is the distance from the Lambirth Number 1 well, the Enserch Lambirth Number 1.

The Y axis represents pressure and goes from 1700 pounds to 2600 pounds.

The lease line is shown at about 660 feet, so you can see that it's equidistant.

Again, the same assumptions apply here: steady-state flow, it's an impotent-acting reservoir. These are based on single wells, only one well in the reservoir. And that's a shortcoming of this exhibit, but it's done to simplify the problem; we could have a real complicated model here. We're just trying to simplify.

It assumes that the permeability is constant per well, no skin. And it's Darcy's law, the most basic reservoir engineering calculations.

What it's showing, it's showing based on the fluid level provided by Phillips, according to Phillips they had shot a fluid level to their well on June 21st 1995 [*sic*] of 1830 feet from the surface, and we calculated a bottomhole pressure of 1500 -- I'm sorry, of 2144 p.s.i., based on 1579 barrels of fluid withdrawn.

We matched the permeability with those parameters, and with the latest data we have, using 3263 barrels of withdrawal, we calculated a bottomhole pressure of 1743 p.s.i., which would be the intercept to the right corner of the diagram.

So what this represents is Enserch's pressure drawdown versus Phillips' pressure drawdown. It's showing that Phillips is able to draw down the reservoir 773 p.s.i. while Enserch is only able to draw their well down 200 p.s.i.

There are some shortcomings with the exhibit, based on the assumptions. But what it's showing is that -- It's showing a no-flow boundary way over on Enserch's property. In fact, it's occurring at around a point of 165 feet from Enserch's well. And a no-flow boundary would be if there were a drop of oil sitting at this distance, 165 feet from Enserch's well, it would not know whether to go to Enserch's well or to Phillips' well.

What this exhibit shows is that Phillips is draining Enserch's acreage, and it also shows that they have an advantage of a drawdown practically four times greater than what Enserch is enjoying.

Q. Mr. Burkett, what you've done is, you've taken the information on Exhibit 13 and added the Lambirth Number 2 A, the Phillips well, to the exhibit?

A. Yes, sir.

Q. What you have been able to show here is that within the limits of the information used, that in fact there's a four times greater drawdown by the Phillips well in the reservoir than what you've been able to achieve?

A. Yes, sir.

Q. And the information that you have on this exhibit is what -- the kind of drawdown you're able to achieve using the existing large submersible pump and under existing well conditions?

A. That is correct.

Q. Now, if you model this reservoir, you could obtain a more refined information or data on exactly what's happening; is that not right?

A. That is correct. And we've played with different parameters, we've adjusted the parameters, but the bottom line is, the character of the curves are still the same. And regardless of what we vary, in every case it reverts back to the no-flow boundary being way over on Enserch's property.

Q. In other words, the data may change, but in your opinion the conclusions would not?

A. That is correct, the conclusions will still be the same, that Phillips has an advantage over Enserch, even with our higher withdrawal rates.

Q. What conclusions have you reached, based on your review of this reservoir, concerning the impact of granting this Application on the correlative rights of interest owners in the pool?

A. Correlative rights will not be damaged by granting the special allowable. What we see is that Phillips is enjoying a four-times greater drawdown. They're drawing on a reservoir four times greater than Enserch is capable of drawing on it, and that we see a net drainage in the direction of Phillips.

Q. Is what you're proposing an effort to in fact offset drainage with counter-drainage?

A. That is correct, to the extent that we can.

Q. And what additional increase and recovery are you hoping to achieve?

A. We will only partly be able to counter the drainage, and as Mr. Telford mentioned earlier, we should see an increase of 456,000 barrels incremental.

This is based on two factors. One is the stripping effect of moving more volumes of water through the reservoir from the fractional flow curve.

And the other is the increased drawdown. As we increase the pressure drawdown in the reservoir, we will force the matrix to feed. We have a higher column than Phillips does, so therefore we have more matrix oil than Phillips does. But by increasing this drawdown, we should get the matrix to feed into the fractures and therefore increase recoveries, and that's what the theory says, that's what we're seeing from our production data.

Q. How does the potential for a loss of casing impact the correlative rights of Enserch in the pool?

A. Well, as Mr. Telford mentioned, we have lost 41 percent of our wells out there, we've lost 460,000 barrels of reserves. And if we lose this wellbore, we will not be able to compete or we will not have the opportunity to produce our -- the reserves on Enserch's lease.

Q. Now, you see no adverse impact on the correlative rights of Phillips; is that right?

A. None at all.

Q. What impact would there be on the correlative rights of Enserch if in fact the Application is denied?

A. Phillips will still enjoy an advantage and Enserch will not be able to compete with Phillips. Basically, we'll be denied the opportunity to compete.

Q. Were Exhibits 13 and 14 prepared by you or under your supervision?

A. Yes, they were.

MR. CARR: At this time we move the admission of Enserch Exhibits 13 and 14.

CHAIRMAN LEMAY: Without objection, Exhibits 13 and 14 will be admitted into the record.

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

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. I'm sorry, is your last name Burkett?

A. Burkett, yes, sir.

Q. Burkett.

A. Yes, sir.

Q. Mr. Burkett, describe for me again, sir, what is it that you do?

A. I am the district petroleum engineer. I'm over engineering operations for the west Texas district for Enserch Exploration. My regional boundaries are the Rocky Mountains, west Texas and New Mexico region. I'm responsible for all engineering operations.

Q. All right. Now, within the context of your work --

A. Yes, sir.

Q. -- are you applying reservoir engineering experience to this hearing?

A. Yes, sir.

Q. All right. Do you also have in your capacity the production responsibilities that we would see with a normal production engineer?

A. Yes, sir, we're responsible for production and reservoir engineering, all production reservoir engineering functions.

Q. All right. You would be familiar, then, with how the Phillips 2 A well and your Number 1 well are configured?

A. Yes, sir.

Q. All right. Both those wells have 5-1/2-inch casing, I believe?

A. I'm not certain of theirs, but I am certain of ours, yes, sir.

Q. Are you aware that both wells are using approximately the same size high-volume lift system?

A. I have heard that Phillips has installed a larger submersible pump. I've heard that, it's been hearsay.

Q. All right. The rates of production on your well that we've used in your model --

A. Yes, sir.

Q. -- were you using 500 or 600 barrels of oil a day?

A. Those were based on the last test we had, which was -- actually, I used a -- I used 4403 barrels per day of total fluid, and the permeability we used was a combination of oil and water permeability.

Q. Okay. Let me see if I understand how you've constructed the model --

A. Okay.

Q. -- upon which you've based your conclusions. I have seen that done, that this basic engineering model was simply a depletion drive reservoir.

A. Okay.

Q. Is that not what this is often used for?

A. Yes, it is. In fact, we varied it for a pseudo-steady-state. But for this -- for trying to simplify the model, we've gone back to a steady-state flow with a constant pressure boundary at a half a mile. It's an arbitrary number. We varied it from 1320 to a mile. We played around with it. It still exhibits the same results, regardless of what we use for RE, regardless of whether we use pseudo-steady-state or steady state. the basic concept is still the same.

Q. All right. You're using a computer-assisted program of some kind?

A. Yes, sir, a spreadsheet with simple Darcy's law.

Q. All right. This is not one of those sophisticated reservoir simulations where you're putting in these reservoir parameters and modeling the performance of these two wells within a certain container?

A. No, sir.

Q. All right. This model does not have inputted into it the geologic conclusions that Mr. Faigle has described for us in terms of size, shape and structural position?

A. Other than feet of pay, no, it does not.

Q. All right.

A. It's a very simplified model.

Q. When we look at this model then, what we're looking at is a container of a certain horizontal dimension, if you will?

A. Yes.

Q. What dimension did you use?

A. I used a drainage radius of 2640, one-half mile.

Q. And the model uses one well?

A. One well, yes, sir.

Q. And within that horizontal extent, you also have a vertical component?

A. Yes, sir.

Q. Within that container, then, the assumptions of the model are that they will have a certain uniform porosity?

A. Yes, sir.

Q. It assumes a certain uniform permeability?

A. That is correct.

Q. It will make no differentiation as to structure?

A. That is correct.

Q. It will not take into consideration whether or not this is a bottom water drive or an edge water drive reservoir?

A. That's right.

MR. KELLAHIN: All right, no further questions.

CHAIRMAN LEMAY: Thank you.

MR. CARR: I have one question.

REDIRECT EXAMINATION

BY MR. CARR:

Q. In this model, is porosity a factor?

A. No, it is not a factor.

MR. CARR: That's all.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. What was the KH at both wells?

A. We determined this with an iterative procedure, it was trial and error. And in the Lambirth Number 1, I used 208 millidarcies with 72 feet of pay.

Now, Mr. Faigle had reported a pressure buildup test that was done in 1978 of 500 millidarcies. And that is correct, that was a pressure buildup test done at that time. It was based on 50 feet of pay instead of 72 feet of pay. So the numbers are approximately correct.

My permeability or the permeability I've used here is a combination of oil and water. That permeability was calculated back when it was totally oil saturation. So it's close.

On the Lambirth A 2 well, our iterative calculations, we came up with 94 millidarcies and 30 feet of pay. This is substantially higher than was reported from core analysis, and I'm concerned that maybe core analysis -- maybe they used plug cores instead of hole cores, maybe. But it -- Had I used their lower number of about three to four millidarcies, it would make the no-flow boundary even further on our lease.

So I've just gone with what fits, just using the data that fits.

Q. And is there any engineering evidence that that supports the fractures?

A. Yes, sir, there was a study done by RPI that shows a permeability distribution, and they also showed a bimodal distribution of fracture and matrix porosity.

Q. That was based on cores?

A. On cores, yes, sir.

Q. Very good.

A. And that was presented in the Examiner hearing previously. We submitted that as an exhibit.

COMMISSIONER WEISS: Thank you, I have no other questions.

CHAIRMAN LEMAY: Commissioner Carlson?

COMMISSIONER CARLSON: That's all right. He covered it.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. I probably should have asked this early on, but I'll ask you because it's a question I had and didn't ask.

The Pennsylvanian oil and the Fusselman oil, are they similar?

A. They're very similar.

Q. So it would be hard to differentiate between the two?

A. It would be, yes, sir.

Q. Bear with me; I'm a geologist, not an engineer.

A. Okay.

Q. You have this drop of oil there, and depending on which way it's going to move, you've done that with pressures.

A. Yes, sir.

Q. But with a water drive reservoir wouldn't that drop of oil just stay there and you'd have the movement from the bottom up of water so that -- The molecules aren't going in either direction, but what you're trying to control is the rate of water coming up the pay section, aren't you?

A. That's right. According to how we see the reservoir, this drop of oil would have to be in the matrix, because the water has already moved above -- You know, it's already watered everything out through the fracture system.

Q. Okay.

A. And so the pressure is pretty much equalized.

Q. Okay.

A. Now, when we increase -- when we install the high-volume lift, we increase the drawdown, we're pulling the water through the fractures. Well, finally we're getting this little drop of oil to come from the matrix into the fractures.

Phillips is doing it from their end, we're doing it from our end, and that drop of oil would be at some point, according to this model, on our lease, would be that no-flow boundary where the drop of oil in the matrix would come out into the fractures and have to decide which way to go, whether to go to Phillips' well or our well.

Does that confuse you?

Q. Yeah, it does.

A. Okay.

Q. You're changing a water drive reservoir, then, to a gas-solution-type drive reservoir? Or what happens with the oil in the matrix that's coming into the fracture system? Is it going to be influenced by some water that's in the fracture system there or what?

A. It should be, and what we feel we're doing with the high-volume lift is pulling so much water through the fractures, and perhaps four or five pore volumes of water through the fractures, that any matrix oil that seeps into the fractures will ultimately end up in the wellbore.

And so the way we envision the model, as we increase the drawdown or we pull harder on the fractures, we're able to alleviate oil -- or move oil from the matrix into the fractures.

Q. So your whole reservoir has become a different mechanism; you're sucking the oil out of the matrix, rather than letting the water move the oil up into the wellbore?

A. That's correct, yes, sir, that's correct.

In effect, it goes back to what Mr. Faigle was talking about, about we've watered everything out. You know, we've watered out the fracture system. We still have matrix oil in place.

You know, we have a higher amount of matrix oil than does Phillips because we were located higher above the oil-water contact. So while -- We have a lot more bypassed oil than Phillips does, because we're located higher structurally. And as we increase drawdowns then we should recover more -- larger amounts of oil, because we have more oil in the matrix system. So we should recover higher volumes from high-volume lift.

Phillips has done this for about three years, and they recovered a lot of oil, but they're not as high in the column, so they haven't recovered as much as we should, because we have a higher column, a higher matrix oil column.

Q. Any idea of percentage of total oil in place in the fractures and in the matrix?

A. I'm not aware of any, I'm not aware of any.

Q. Well, it looks like you've got a half a million barrels left.

Do you know how much the well has produced already?

A. With a million barrels, right, at a million barrels. It's been a very, very good well.

Q. Yeah. So basically there's more oil in the fractures, I guess, than in the matrix to start with, and now you're working on the matrix, which is harder to get out?

A. Probably it's going to be harder to get out. We'll probably leave a lot of oil behind.

Q. How much, percentage of oil in place?

A. I haven't done any calculations on it, but the drawdowns we're seeing -- most of our drawdowns occur in the first 150 feet. So I think the bulk of our recoveries, you know, come from that 150 feet. We feel like we'll leave a lot of oil in place.

CHAIRMAN LEMAY: Take a break? Fifteen-minute break?

(Thereupon, a recess was taken at 10:35 a.m.)

(The following proceedings had at 11:00 a.m.)

CHAIRMAN LEMAY: Does that complete your --

MR. CARR: That concludes our presentation, Mr. Chairman.

CHAIRMAN LEMAY: Thank you.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

We're going to present two witnesses to you. Scott Balke is a petroleum geologist with Phillips. He testified at the original Examiner hearing. I'm going to call him first.

The second witness is Jack Pickett. Mr. Pickett is a petroleum engineer. In addition, he also testified before Examiner Stogner.

At this time I'll ask Scott to take the witness stand.

SCOTT BALKE,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. For the record, would you please state your name and occupation?

A. Scott Balke, I'm a geologist for Phillips Petroleum.

Q. On prior occasions, Mr. Balke, have you testified before the Oil Conservation Division in the capacity as an expert in the area of petroleum geology?

A. Yes, I have.

Q. Summarize for us your education.

A. I got an undergraduate degree at the University of Colorado; a graduate degree, Oklahoma State University.

Q. In what years, sir?

A. Undergraduate degree was 1978 through 1982; graduate degree was 1982 to 1984.

Q. Do you have geologic experience in southeastern

New Mexico, west Texas?

A. Yes, I do.

Q. Does that experience include the Fusselman production that we've talked about this morning and what is identified by the Division as the South Peterson-Fusselman Pool?

A. Yes, it does.

Q. How did you first become familiar as a geologist with that particular production?

A. Originally I was part of the RPI study. There was a consortium of companies who did a Siluro-Devonian study in west Texas, New Mexico.

Q. That RPI study was referenced by one of Mr. Carr's witnesses a while ago. Describe for us what that was.

A. The study was a group, it was a consulting group out of Boulder, Colorado, that wanted to study the particular characteristics of Siluro-Devonian throughout the Permian Basin, and so each -- several of the oil companies gave both money and cores and information to the study so they could all collaborate the information and get the best results from all the information available.

Q. What's the particular time frame for that RPI study?

A. It started -- gosh, probably back in -- The original beginning work was probably back in 1988, something like that. The conclusions took place probably late 1989, something like that.

Q. Apart from contributing to that study effort, do you have other independent involvement with the Fusselman production in this pool?

A. Yes, my duties -- We're responsible for all fields within New Mexico, and part of those were the South Peterson field here.

Q. How many years of your professional geologic experience includes your involvement with the Fusselman Pool?

A. Close to six years.

Q. In addition, did you make a specific study of and geologic conclusions and recommendations to Examiner Stogner back in the June, 1994, hearing?

A. Yes, I did.

Q. Have you continued to study the geology involved in this particular pool?

A. Yes, I have.

Q. And based upon that study, do you now have certain geologic conclusions and opinions?

A. Yes, I do.

MR. KELLAHIN: We tender Mr. Balke as a geologist.

MR. CARR: No objection.

CHAIRMAN LEMAY: His qualifications are acceptable. Balke, is it?

THE WITNESS: Yeah, B as in boy, a-l-k-e.

CHAIRMAN LEMAY: Thank you.

Q. (By Mr. Kellahin) Mr. Balke, what I think I'm going to do is take some of your exhibits out of order. I think I -- I don't want to surprise you, but I'd like to take that cartoon that you have prepared so that we can have you characterize the reservoir for us.

A. Okay.

MR. KELLAHIN: Can you see that, Mr. Carr?

MR. CARR: No, if I can step over --

MR. KELLAHIN: Now can you see it?

Q. (By Mr. Kellahin) Let me direct your attention to what we've marked as Phillips Exhibit Number 6, I believe it is.

A. Five.

Q. I'm sorry, 5. What's the base display?

A. What you're seeing here is very much --

Q. I'm sorry, I asked you the wrong question. Looking -- Where did that display come from originally?

A. Oh, excuse me. It came from Mr. Faigle's presentation back in June.

Q. What then did you do to his characterization or representation of the reservoir?

A. I tried to implore [*sic*] our understanding of the water drive mechanism of the reservoir and how it applies to the geological framework.

Q. Let me divide this into sections for you, Mr. Balke. If you would give us a characterization of the Fusselman reservoir, what kind of rock are we looking at? What's its deposition? Just give us a general summary geologically of how you would characterize the reservoir.

A. The geological parameters I'm going to show came from the core that we took in the Lambirth 2 A and the geological work I did throughout the field.

I agree with Mr. Faigle that it is a fractured dolomite reservoir, heterogenous, fracture with matrix porosity. The porosity comes from both the fractures and from the matrix -- intercrystalline porosity itself. The key --

Q. Do you subscribe to the theory that this reservoir is a dual-permeability system?

A. Dual-permeability system, but with a significant factor of being only fractures, being your core permeability, I guess your primary permeability component.

Your fractures are going to be your conduits, with your matrix porosity being your storage capacity. Your fractures are going to be what's going to transport the oil from both the fracture system and the matrix up through the borehole.

Q. Characterize, then, the reservoir, please.

A. It's a highly fractured permeable reservoir where your communication within your reservoir occurs throughout the reservoir itself, throughout the Fusselman itself.

You -- Again, like I previously said, your fractures are going to be your conduits. It's just like a building with doorways and hallways. Your rooms are going to be where the storage capacity is going to be, but to get through the rooms outside, you've got to go through the hallways, which are the fracture systems.

Q. What is the trapping mechanism by which the hydrocarbons were accumulated and stored?

A. Structurally trapped and stored both within the fractures and within the matrix porosity.

Q. Is there a water component to the reservoir?

A. Yes, there is.

Q. Do you have an opinion as to where the original oil-water contact was in this reservoir?

A. The original oil-water contact is going to be very similar with Mr. Faigle's.

Q. So you don't have any disagreement with him --

A. Don't have any --

Q. -- as to the subsea depth at minus 3450?

A. No problems at all.

Q. Do you subscribe to the theory that this is an active bottom water drive reservoir?

A. Not only an active bottom water reservoir -- bottom drive reservoir, there's a key component, probably a significant component of an edge water drive reservoir. This is based upon geological maps and performance of the wells.

Q. If we look at Mr. Faigle's cross-section that is on the other display board, and if you'll look at the red line that depicts the minus 3450 subsea location of the original oil-water contact, describe for us why you as a geologist do not agree that this is an exclusive bottom water drive reservoir.

A. If -- Just like Mr. Faigle said, if you had had a constant bottom drive reservoir, giving some slack and some variances granted, you would see the water rise in each one of these wells, you'd see the lower structural wells water out or see at least water encroachment earlier than the wells up on top.

And when I show you my structure map, I will show you wells that watered out and produced a lot more, significantly more water, with the same structural elevation. So that proves that it can't be a single bottom water drive, because you have the same subsea depth wells watering out at different times, significantly different times, so it could not be a single bottom water drive.

Q. Can you give us an illustration of a comparison between two wells --

A. Uh-huh.

Q. -- where you would have expected one well to have substantially increased its water cut if in fact it was being affected by water -- a bottom water drive mechanism?

A. Yes, sir, if you could look at my Exhibit Number 3, which is a structure map on the Fusselman itself, within Section 31 there we have a Number 2 well, which is our Enserch 2 A well, which is a subsea depth of minus 3419, and the Number 1 well, which has a subsea depth of minus 3406. Actually, our Number 2 well is slightly structurally lower than the Number 1 well there.

However, water -- and in fact the water -- or the well became uneconomical because of water much earlier in the Number 1 well than it did in the Number 2 well. Now, if this was a strictly bottom water drive, that phenomenon would not take place.

Q. When you compare the Enserch Number 1 Lambirth with the Phillips A 2 Lambirth in terms of the approximate time frame within which each of those wells began to experience substantial increases in water cut, what's the relationship and what did you see?

A. The Number 2 well should be encountering water before the Number 1 well, and that's because it's structurally lower. You have a complete fractured reservoir right there, so they're in communication with themselves. And you would see the Number 1 well, being structurally higher, seeing water much later.

Q. And what happened?

A. That is the case.

Q. Describe for us, then, geologically what you see to have occurred as we look at Exhibit 5, the cartoon.

A. Uh-huh.

Q. With the original oil-water contact as you see it and with these wells and this geologic data, describe for us what's happened.

A. Well, because this was a -- this fracture system was not only fractured but it also had solution enhancement done for diagenesis, you had significant communication within the wells. And as the Number 1 well increased its rate, and because of its structurally favorable position, you're going to see water encroachment coming up at an accelerated rate, especially if it's produced at a higher rate, and will prematurely water out our Number 2 A Lambirth.

Q. When you say "water coming up", can you describe for us in what directions this water is encroaching?

A. It will come up from the edge, along with the bottom, but it will also come up from the edge, because we see, based upon our structure map and based upon our well performance, that there's a strong edge water drive component to it. So you'll see water coming up on the edge of the reservoir itself.

Q. Have you also studied the structural relationship between the Enserch Lambirth 1 and the Phillips Lambirth A 2 well?

A. Yes.

Q. What is your opinion about the vertical difference in the top perforations between those two wells in this pool?

A. The Number 1 Lambirth well will experience a structurally favored position of about 38 feet, approximately 38 feet, and that will give them a significant structural advantage over our Number 2 well.

And that advantage, because of the structure and because we're seeing that the fracture patterns are all broken up so that the reservoir is in communication with itself, will be a significant advantage for Enserch over Phillips.

Q. Mr. Faigle subscribes to the proposition that at this point in the reservoir, if there was an advantage structurally, it simply no longer matters for remaining oil production because the fracture system is watered out.

Do you agree?

A. Well, I'd even kind of piggy-back on top of what Mr. Burkett also said: It takes the matrix to feed into the fractures to produce the oil. Your storage capacity is in the frac- -- excuse me, is in the matrix. And it's the fractures that are going to be able to bring the oil to the well itself.

So I don't agree with Mr. Faigle because I think that your fractures are not watered out, they're just carrying the remnant oil that they carry and also the oil that's coming from the matrix.

Q. In your opinion, does the structural differentiation between the two wells still matter in terms of remaining depletion of the reservoir?

A. Significantly, without doubt.

Q. From a geologic perspective, will rate matter?

A. Yes, it will.

Q. In what way?

A. As you see, both on the diagrams and on this structure map, you're having this reservoir being in communication with itself, both -- There's no vertical permeability barriers, there's no horizontal permeability barriers. With the wells being higher up on the structure, you'll have the advantage.

Is that -- I think I've lost your question a little bit, but maybe that answers it.

Q. Well, let me ask you a different way. If the maximum oil rate is still 267 a day and continues the historical level of that withdrawal rate, versus increasing it to 500 barrels a day, does it matter?

A. Yes, it does. If you increase your rate, you will have adverse effects on Phillips wells, on the Phillips Well Number 2, to be specific. Increased rate will increase the water into our well.

Q. When we look at the producing interval in the reservoir above the original oil-water contact, do you see variations in porosity as we move through the reservoir?

A. There are some variations. However, it's pretty consistent at about 9.5 percent, the core analysis that was done, but on the Number 2 well was hole-core analysis. But the key component -- And we can get to it if I may?

Q. Yes, sir.

A. Go to Exhibit Number 5.

Q. I'm sorry, I think you're looking at 4.

A. Excuse me, you're right, 4.

Q. All right, we'll get it straight yet.

A. Okay.

Q. Four is RPI information from the study?

A. That's correct.

Q. Take a moment and identify each page, and then let's go back and talk about what it means.

A. The first page is a cross-plot of core porosity and permeability in the Phillips Lambirth A Number 2.

The second page identifies the distribution of core permeability from samples. So you've got core permeability versus the percent, where it's at.

What I want to show from both of these is, one, yes, there is a heterogenetic relationship in permeability. However, when you compare porosity as on the first page, porosity compared with permeability, you see not a direct relationship at all.

Porosity stays pretty consistent through there, about 9.5 percent. However, permeability can range from being a moderate-permeable rock to a very high-permeable rock. And it's a very high-permeable rock that makes this reservoir a very -- in communication with each other.

Q. When we look at the first page of Exhibit 4, the figure 9.110, specifically what are we looking at?

A. Looking at --

Q. The first page of this exhibit.

A. Yes.

Q. What is that?

A. That's just, again, a correlation between porosity, core porosity, and core permeability within the

Lambirth A Number 2, and showing zones of both moderate porosity -- or moderate permeability and high permeability within a -- essentially the same permeable rock, around 9.5 percent.

Q. How is that of any importance to us in whether we change the rate of oil withdrawals from the pool?

A. The key component here is permeability. We know it has high permeability. So if you change the rate, you're going to have adverse effects on wells that are structurally low to the one that's on high, the highest structural well. It will have an adverse effect on the Lambirth 2 A.

Q. Page 2 of Exhibit 4, it's figure 9.111. Specifically, what are we looking at here?

A. You're looking at essentially the core permeability of the rock itself, and what we're seeing is that the permeability -- just another correlation of the permeability variation.

It shows that it is a heterogeneous -- has heterogeneous distribution, and RPI's conclusions were that this resulted in premature water breakthrough in the reservoir, could allow for that.

Q. Put that last sentence in some kind of geologic context for us so we can see its significance as we address how these two wells compete for the remaining oil.

A. What we saw was, this reservoir was not atypical from any other carbonate reservoir within the Permian Basin. You had highly permeable rock. You know, if you had too fast of expulsion of the fluids themselves, specifically the oil, you could have premature breakthrough of the water through the -- into the borehole, which -- I mean, it's a direct relationship to what Enserch is proposing here. If you increase the rate too fast, you have bypassed oil.

Q. How does the fact that in your opinion there is an edge drive water component to the reservoir fit within the context of the potential for premature water breakthrough in the reservoir?

A. Okay, you're going to have increase of water coming up from the edge. And along with the strong -- Because of the strong water drive, you're going to have premature water breakthrough because it is very highly permeable, and you'll have increased water within certain downdip wells.

Q. When you look at the porosity characteristics in the log for the Enserch Lambirth 1 well -- A copy of that is on the display board. When you look at the lower perforations within that section versus the higher perforations, is there any distinguishable difference in ranges of porosity?

A. Yes, there are. There's -- Where they perforated was in the higher permeable -- or excuse me, higher porosity zones. And then where they didn't perforate was in the lower porosity zones.

Q. In the lower porosity zones, what range of porosity values do you find in their well above the oil-water contact?

A. Probably an average porosity of, say, around ten percent.

Q. And as we move up into the area of the reservoir that they did perforate, what kind of porosity value are you finding?

A. Probably a low of a cross-plot porosity of, say, 12 percent, to a high of close to 18, 20 percent, somewhere around that range.

Q. When you read across and correlate those points to the porosity values on your 2 A well, what kind of porosity value do you have?

A. Cross-plot porosity of approximately 12 percent.

Q. Is there a material difference in terms of porosity values, then, between the two wells?

A. Yes, there is.

Q. Okay, with the advantage lying where?

A. The advantage lying with the Enserch Number 1 well.

Q. Let me go back and have you identify those exhibits that we haven't specifically addressed.

If you'll look at Exhibit 1 and for the record describe and identify that display.

A. Exhibit 1 is a base map of the South Peterson field itself, and Section 31 gives you the wells in question, specifically the Enserch well, which is located in the northeast of the southwest quarter; the Phillips 2 A well, which is located in the southeast of the northwest quarter of Section 31. And each well has its well number and operator number above it.

Q. How did we end up, just for historical information, in this checkerboarded fashion, Mr. Balke?

A. It was Phillips' farmouts, and Phillips gave a farmout on a checkerboard-type arrangement. Therefore, if Enserch -- which in this case they did, they were successful in their initial well, we would have offsetting to locations to develop ourselves.

Q. Exhibit 2, you don't have to describe it in detail, but just tell us what it shows and the point of time at which you tabulated the production data.

A. Production data was current through 12 of 1993. The Enserch Well Number at that time had done just a little bit below a million barrels of oil. Our Number 2 A well had done approximately 410,000, 411,000 barrels of oil.

And you'll see the production around each of the other wells also.

Q. All right, let's go back then to Exhibit 3, which is your structure map, and let's spend a few minutes on this. This represents your work product, does it not?

A. That's correct.

Q. When we look at the trapping mechanism in the reservoir, describe for us how you've illustrated that.

A. The trap within this reservoir is structural. The structure experienced both fracturing and subareal exposure, with truncation of the Fusselman directly below. That wavy line right there shows the erosional and conforming pinchout.

And near the pinchout, you'll see some of the wells that well performance isn't quite as good. This is because of their location to the pinchout with clay infill within some of the fractures themselves.

Q. When we look at the point on which you're contouring, it is what, sir?

A. What I consider the top of the Fusselman.

Q. All right. Is there a log or some point that you can show us on another display that will give the Commission a reference to where that is?

A. We could use Enserch's cross-section right here. I have no debate with where they're calling the top, the --

in this case they're calling it the lower paleozoic carbonate; I call it the top of the Fusselman. Basically the base of the Penn.

Q. I'm going to hand you Mr. Faigle's Exhibit 3 on which he has prepared his cross-section.

There are obvious differences between your structure map and his structure map. Would you explain to us what those differences are?

A. Okay, just a second, let me just check his numbers.

I believe the difference is, he's picking it -- The significant difference is, I guess, the Number 1 well, I've got it a little bit deeper. He's picking it a little higher, looking more into the porosity range or, I guess, deeper into the rock itself.

But both of us show a structural high up on the Number 1 with truncation to the south, and both Enserch wells and Phillips wells around the Number 1 being structurally lower.

Q. With those general points of agreement, is there any material difference in terms of the contouring conclusions, whether you choose Mr. Faigle's style or your style of identifying the reservoir structure?

A. None whatsoever. Both of us have the Enserch Number 1 well being structurally high and the Phillips well, the 2 A Lambirth, being structurally low.

Q. If you'll look at your structure map, then, can you use that to illustrate what we would have expected to happen to this group of wells had this reservoir been an exclusively bottom-drive reservoir?

A. If we look at Mr. Faigle's exhibit here, you would see that the Lambirth 2 A, the Lambirth Number 3 Enserch, and the Lambirth Number 3, and the Phillips 1 A Lambirth, would essentially have -- and barring some differences -- would have watered out essentially all at the same time, approximately the same time.

Yes, there's going to be some variances there, but they'll be relatively minor. But you'd see each one of those wells becoming uncommercial, uneconomic at about the same time.

Q. And did that happen?

A. No, it did not.

Q. Based upon your work, your study, having heard their presentation, summarize for us your geologic conclusions and your concerns within the context of this particular case.

A. My conclusions are, and very similar to Mr. Faigle's in many ways, is that it is a highly fractured dolomite reservoir, heterogeneous, the fractures being highly permeable, some oil being left remaining within the matrix itself and possibly within the fractures.

Because of diagenesis, subareal exposure and solution enhancement, this is a very highly permeable reservoir with no vertical or horizontal permeability barriers within this reservoir.

My concerns are for Phillips that, Enserch being highest on the structure, Phillips having wells on the -- lower on the structure, particularly the Number 2 A Lambirth, will see water encroachment considerably earlier and will be detrimentally affected by Enserch's proposal here to increase rate.

Increasing rate will have adverse effects on Phillips' wells, because you'll have water coming earlier.

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

We move the introduction of his Exhibits 1 through 5.

CHAIRMAN LEMAY: 1 through 5 will be admitted without objection.

And your witness, Mr. Carr.

MR. CARR: Thank you, Mr. LeMay.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Balke, several things we're in agreement on. We do agree we've got a dual-porosity system or a bimodal system in the reservoir?

A. In process, correct.

Q. And we -- Is it fair to understand that the fractures are the primary conduits for the movement of the oil to the wellbore?

A. That's correct.

Q. In your opinion, is there much oil left in those fracture systems at this time?

A. That's probably more of a -- for Mr. Pickett to address, but I would think there is significant oil still left to be remaining.

Q. Should I address questions about where remaining oil would be, matrix versus fracture system, to Mr. Pickett?

A. That would be fine, or however you would like.

Q. Do you have an opinion as to whether or not the bulk of the oil to be recovered is within the matrix?

A. I think your matrix is probably your storage facility, and your -- and the remaining oil, in my opinion, probably would be in the matrix.

Q. And is it fair to say that to get that oil out of the matrix you have to have something in the reservoir to cause it to move, like a pressure differential; is that not true?

A. I'll leave that one for Mr. Pickett.

Q. Now, if I understood your testimony, you agreed that this is a water bottom drive, but there is also a side water drive component in it; is that correct?

A. That is correct, a significant, probably the pronouncement [*sic*] of the edge water drive, correct.

Q. If we look at the cartoon you have presented, this is not really designed to be an accurate representation of what's occurring in the reservoir, is it?

A. I think it's a conceptual model of what's occurring in the reservoir.

Q. Now, it basically, if we look at it, it shows the water contact. Is that that blue line that runs across it? Is that an oil-water contact in the reservoir?

A. I would say that's where you have an approximate commercial line. I think your oil-water contact could be significantly higher, but that line will probably be where you have so much water that your wells become uneconomical to produce.

Q. If we have a well like the Lambirth Number 1 that has a 90-percent-plus water cut, it would be logical to expect that there would be some substantial water in the reservoir above that line; is that not fair to say?

A. Fair to say.

Q. If we look at this cartoon, and if we had just a bottom water drive reservoir, in fact, we would see an oil-water contact that would be actually the reverse of what we've got here; isn't that right?

The wells that were producing would be pulling the water -- pulling on the aquifer and pulling it up, not -- So you would have it actually rising in the center, not dropping, if it were just a bottom water drive; isn't that correct?

A. That would be correct.

Q. And in fact, the wells that were pulling the most would be coning water up into those wellbores?

A. That would be correct.

Q. But you're not seeing that here in a predominantly bottom water drive reservoir. What this shows is effect -- the -- what occurs with a side water drive; isn't that right?

A. Correct.

Q. And yet it is fair to say that the dominant reservoir drive mechanism is a bottom water drive?

A. I would say that's not what I -- my geological parameters or my geological conclusions came to, but I would again defer that with Mr. Pickett.

Q. So you're not telling us what kind of a water drive we have in the reservoir?

A. I think our conclusions, from my geological conclusions, say that it's a component of both edge water and bottom water drive, and I'd say that a significant contribution is probably edge water, based upon what I see in my structure map and well performance.

Q. And my question is, this cartoon does not show the effect of bottom water drive; it shows edge water drive?

A. It does show bottom water drive, because you do have the bottom portion of the blue coming up from the original oil-water contact. It just shows a more significant edge water drive than just a strict bottom water drive.

Q. And this doesn't, in fact, really show any of the effect of a bottom water drive, or we'd see this line coning up into the wells that are pulling on the aquifer?

A. Well, what you're dealing with -- what you're specifically saying is where the original oil-water contact is. That's not what I'm showing here. The blue is not an oil-water contact, but where my economic -- perhaps an economic water contact may be.

Q. And it doesn't show the effect of pulling, the wells that are producing the hardest, it doesn't show the effect that has on this bottom line?

A. That is a conceptual diagram with what I'm seeing off of my structure map itself.

Q. Rate certainly matters, you testified, in the way these wells are produced?

A. Correct.

Q. And the rate at which the wells are produced -- i.e., the Lambirth, the Phillips -- the Enserch wells produced, you testified, would have an impact on the Enserch well; isn't that what you testified?

I'm sorry, the Enserch well's rate of production would have impact on the Phillips well?

A. Yes.

Q. All right. If I could remember who everybody was, it would be easier.

A. Right.

Q. All right. Isn't that because of the drawdown effect on the reservoir by producing these wells? If we produce our well faster, there would be a greater drawdown?

A. When we get to specifically speaking about drawdown, again, I would defer to Mr. Pickett.

But in a geological sense, I would say that what I'm seeing here, based upon my structure and well performance, is not a single bottom water drive.

Q. And so you're not testifying about the effect of the drawdown on -- from our well on the Phillips well?

A. What I'm testifying here is saying that it's not a strict bottom water drive reservoir, that the reservoir is fractured and in communication with each other and has no barriers, and from a geological perspective, based upon my geological evidence and well performance, that we'd be adversely affected by increasing the rate by Enserch.

Q. And the increased rate, the adverse effect of the increased rate comes from what? Pressure drawdown?

A. Increasing the water in a lateral sense into our wellbore.

Q. And it would also increase the water in a vertical sense, coming up into the reservoir, would it not?

A. There will be some significant increase from the bottom, correct, but I think your major component would be from the side.

Q. We looked at the reservoir, and I believe you testified looking at exhibits from the study that you participated in, and you concluded that the higher permeabilities in the reservoir would in fact cause higher drawdowns. Did you testify to that?

A. I didn't say higher drawdowns. I said that the higher permeability within the rock would pose no communication -- or -- exactly, communication barriers between the rocks. I see nothing in there. They should be all in communication with each other, based upon these higher permeabilities.

Q. And so you looked at the fact that they're in communication with each other. Did you take that the next step and talk about the impact withdrawals from one well would have on the other, or is that again something for Mr. Pickett?

A. I will defer that to Mr. Pickett. However -- No, I'll just defer that to Mr. Pickett. He can explain that, hopefully, a little bit better than me.

Q. We look at the permeabilities from the study, and if I look at the second page of your study it shows a permeability, I believe, for your Lambirth 2 A of 3.8 millidarcies; is that right?

A. That's correct.

Q. And you would agree with me that the permeability in the offsetting Enserch well is 500 millidarcies?

A. That was determined based upon a totally different parameter. We're looking at core permeabilities right here. Your test gave well-performance permeabilities.

Q. Do you have well-performance permeabilities on the Lambirth A Number 2?

A. I again will give that one to Mr. Pickett. All I can -- really concerned with what I know as far as geology in the reservoir.

Q. When we look at the time frame within which the various wells in the reservoir have watered out, do you have a definition for me of what watering out actually means?

A. For us it would be when it became uncommercial to produce. Our lifting costs would be more than what our revenue would be from the oil.

Q. So it would have an economic component and I guess a water component, as Mr. Faigle testified?

A. No, ours would be strictly an economic --

Q. A strictly economic. Did the -- And that is when you totally terminate producing the well; is that when you consider a well to have watered out?

A. Yes.

Q. Has your 2 A watered out at any time?

A. I'm not aware of such.

Q. The 1 A, in your opinion, has not watered out?

A. The 1 A has not watered out?

Q. Yes.

A. We have ceased producing our Number 1 A.

Q. It has watered out?

A. To the best of my understanding, it is, but again I would like defer that one to Mr. Pickett.

MR. CARR: That's all I have.

One other question -- No, I'm sorry, I'll ask that to Mr. Pickett.

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. On Exhibit 4, there's quite a range -- I guess these are all horizontal permeabilities, huh?

A. That's correct.

Q. All right. Do you suppose that the range of the vertical permeabilities is similar?

A. I would be expecting something like it, to be very similar.

COMMISSIONER WEISS: That's all the questions I have. Thank you.

CHAIRMAN LEMAY: Commissioner Carlson?

EXAMINATION

BY COMMISSIONER CARLSON:

Q. When did the Phillips 1 A well quit producing?

A. We shut it in, I believe, November of this last, past year.

Q. And the 2 A well is still producing?

A. That's correct.

COMMISSIONER CARLSON: That's all I have.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Balke, what about the 3 A? That's a well that confuses me. It's higher than the 2 A, and yet it's produced less oil. Is it still producing?

A. 3 A, is this --

Q. 3 A Lambirth, the one south of the Number 1.

A. Okay, that is currently producing, that's correct.

Q. It is not as good a well as the 2 A, even though it is structurally higher?

A. Mr. Pickett will present the production on that, but it does not produce water, it produces around 20 barrels of oil a day.

What we see from our analysis is that you probably had a lot of infilling of clay and other precipitants within the fracture system due to its proximity to the truncation there to the south.

Q. So you might expect that well wouldn't react with your model of having -- being an excellent reservoir, having high permeability both vertically and horizontally and excellent communication-type --

A. Correct.

Q. -- characteristics?

A. And as you pointed out, it is structurally higher. That's why it's not seeing the water that all the other wells are seeing also.

CHAIRMAN LEMAY: Okay, that's all I have. Thank you.

MR. KELLAHIN: You can leave the displays there, Scott. Take the one you need and --

Mr. Chairman, I've called Jack Pickett to the stand.

JACK PICKETT,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. For the record, Mr. Pickett, please state your name and occupation.

A. My name is Jack Pickett, reservoir engineering supervisor for Phillips Petroleum, located in Odessa, Texas.

Q. What is it that you do as a reservoir engineering supervisor for your company?

A. I supervise other reservoir engineers and then conduct some reservoir engineering studies on my own.

Q. Is this an area, when we look at the South Peterson-Fusselman Pool, that is within your expertise both as an engineer supervisor, as well as a reservoir that you have studied as an engineer?

A. Yes, I worked on the South Peterson Fusselman field in the early Eighties as an area engineer, and -- for about three years. And then I've been in my current position for about seven years, with responsibilities for the whole Permian Basin and -- essentially in New Mexico.

Q. So your involvement in this pool with regards to your production is simply not triggered by Enserch's Application?

A. That's correct.

Q. You've got historical knowledge, separate and apart from your activities in this case?

A. Yes.

Q. Did you testify before Examiner Stogner as an expert in reservoir engineering in this case?

A. Yes.

Q. And have you continued to study the issue of increasing the oil allowable for this pool?

A. Yes.

MR. KELLAHIN: I tender Mr. Pickett as an expert reservoir engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) Mr. Pickett, if the Commission were to grant Enserch's Application to increase the pool allowable for the pool, how many wells would benefit by that increase?

A. One. Just the Enserch Lambirth Number 1 is the only well capable of taking advantage of that increase.

Q. Let me start where I left off with Mr. Balke.

Let's look at Exhibit 5. It's the cartoon that's on the foam board.

As a reservoir engineer, describe for us what you see within Mr. Balke's geologic context as to how the reservoir has been depleted when we use the original oil-water contact of minus 3450. What's happened as the wells produce the fluids from the pool?

A. As the wells have been producing, you can see a lot of edge water or premature water encroachment from the sides, wells that shouldn't have watered out if it was purely a bottom water drive mechanism, watering out before they should have.

Q. All right. Are there illustrations to prove that conclusion?

A. Yes, I'll have several illustrations.

Q. At this point in time, is it still appropriate, in your opinion, to maintain the consistency of keeping the oil rate at 267 barrels of oil a day as the two operators compete for the remaining oil?

A. Certainly no higher.

Q. And why do you say that?

A. The Phillips well will be damaged if -- The function of the water encroachment into the Phillips wells is a function of how much oil Enserch is pulling out of theirs.

Q. When we look at the opportunity to compete for the remaining oil in the pool, how many wells are truly involved in that competition?

A. Three.

Q. All right. Identify for us the three wells that still remain to compete.

A. The Phillips Lambirth A Number 2, the Phillips Lambirth A Number 3, and the Enserch Lambirth Number 1 wells.

Q. Let's look at how you have exercised that opportunity to compete. If you'll look at the Phillips 2 A Lambirth well, how is that well currently configured for production?

A. We've got the largest submersible pump in it that we can put in 5-1/2-inch casing.

Q. And approximately how many total fluid barrels are you able to produce?

A. We're making about 150 barrels of oil and 1500 barrels of water.

Q. All right. Are you familiar with the SPE paper that's been discussed by Enserch in the hearing?

A. Yes, I've read it several times.

Q. All right. When we look at the criteria for accomplishing some opportunity of success with a high-volume lift, have you tried that system in this reservoir?

A. Yes, Phillips has effectively tried that on two wells, and it did not work on either one.

Q. Were you able to try that opportunity within the parameters of the SPE paper where you were dealing with water cuts of between 70 and 95 percent?

A. Yes, both our wells that we installed submersible pumps on had water cuts within that range, and we saw no extra oil as a result of installing submersible pumps, no increased reserves or decrease in water-oil ratio.

Q. As you study information since the last hearing, do you reach any different conclusion about the adverse impact on Phillips' correlative rights if this Application is approved?

A. No, same now as it was then.

Q. Based upon that data, do you have an opinion as to whether or not approval of this Application will increase ultimate oil recovery from the entire pool?

A. I see no information that would indicate increasing the allowable will increase the ultimate recovery.

Q. From the pool?

A. From the pool.

Q. Do you see any information to tell you that the Enserch well has improved its ultimate recovery versus simply accelerated the recovery of the same volume?

A. It's hard to say with a short time period, but it is probably recovering some more reserves, but at Phillips' expense.

Q. Why do you say that?

A. Because it's drawing water in from the sides and watering out Phillips' wells earlier, reducing our reserves and increasing Enserch's reserves.

Q. If we keep the oil rate the same, what does that preserve for Phillips that you don't have if the rates increased?

A. An opportunity to recover our reserves.

Q. You listened to Mr. Burkett's model example of the fact that the advantage is to you --

A. Yes, sir.

Q. -- despite the fact that your well is downstructure, producing less oil and may have less quality in terms of reservoir characteristics?

A. Yes, I heard that testimony.

Q. And what's your opinion?

A. I think it's just the opposite, that Enserch has the advantage and that Phillips does not have an advantage.

Q. What's the flaws, as you see it from a reservoir engineering perspective, in Mr. Burkett's conclusions?

A. Basically, his claim was that Phillips -- the 2 A well was affecting Enserch's well more because we had a greater pressure drawdown, but that's because of the lower permeability.

And if you draw that same kind of reasoning out, you go down to -- if the well had very low permeability, it was only making, say, one barrel of fluid a day, that would even be more of a drawdown, even more of an effect.

So it kind of seems backwards to me that the lower permeability that our well has, the more we affect Enserch, that does not seem correct.

Q. All right, when we look at the opportunity for success under the hypothetical in the SPE paper, is that conditioned on the pressure drawdown that you're able to achieve in the reservoir in that specific well?

A. I believe it touches on that, that it could be a function of the drawdown pressure.

Q. When you look at the other two wells that you tried the high-lift system in --

A. Yes.

Q. -- and could not increase the oil productivity, which two wells did you try that in?

A. In the Lambirth A Number 1 and in the Lambirth A Number 2.

Q. Were you able to achieve a level of pressure drawdown in each of those wells that should have, if the paper were correct, improved?

A. Yes, far beyond what Enserch has drawn their well down, and enough that -- inasmuch as they call -- talk about it in the SPE paper.

Q. All right. And you were not able to achieve the kinds of results that were hypothecated by the paper?

A. Correct.

Q. What do we do, if anything, about this issue of water breakthrough, premature water breakthrough in the reservoir? Is that an issue for you as a reservoir engineer in this pool?

A. Yes.

Q. Why?

A. You have to be concerned about the rates of withdrawals from updip wells, lowering the reserves of the downdip wells.

Q. Let me put this to you a different way. We often talk to this Commission about a reservoir being rate-sensitive or not rate-sensitive.

A. Oh, yes.

Q. In the context of this case, is this reservoir going to be sensitive to rates of fluid withdrawals?

A. No.

Q. All right. What we are concerned with, though, is the opportunity for the movement of the oil within the reservoir?

A. Yes.

Q. So it's a correlative-rights issue, as opposed to a waste issue?

A. Correct.

Q. Let's turn to your exhibit. Your first exhibit is Number 6?

A. Right.

Q. What are we looking at?

A. This is a production plot of Phillips' Lambirth A Number 3 well. It's located one well location south of the Enserch Lambirth Number 1 well.

The oil production is the black line, the water production is the blue line the gas production -- or GOR -- is the red line.

The well is currently making, now, about 22 barrels of oil a day, little or no water, with a GOR of around 1000.

Q. Your perfs in this well are higher structurally than the perfs in your 2 A well?

A. Yes.

Q. All right. And this is structurally higher in the reservoir, as shown in Mr. Balke's structure map?

A. Yes.

Q. It produces zero water and -- what? Twenty-nine barrels of oil in November of 1994?

A. Twenty-two to 30.

Q. All right, and it's currently still producing oil?

A. Yes.

Q. How do you explain this well's performance?

A. Well, if you look at the -- I don't know what you call it. It's fairly inconsistent oil production over the history of the life, but essentially it's flat production for the entire history of the well. I kind of call it non-declining oil production.

And what's also interesting to note is, the gas is still at about the same level it was originally.

What I infer from this information is that this well has got lower productivity than some of the more prolific wells in the field, but it's receiving the pressure support from the aquifer and the water-drive mechanism in the field.

Q. Could this well potentially be affected adversely if the oil rate is increased?

A. This well probably would not be affected.

Q. Let's look to those wells that may be.

A. Okay, the -- One other thing to note on this is that the perforations in this well match up with the top half of the perforations in the Enserch Lambirth Number 1 well, which Enserch has said has watered out, yet this well makes very little water.

Q. All right, you find evidence it's in the same reservoir?

A. Yes.

Q. You find some pressure support for that well?

A. Yes. And --

Q. If it was a true solution drive reservoir and not in communication with the main reservoir, then that shouldn't happen?

A. Right.

Q. So it's getting some support, and it's in the same common source of supply?

A. That's right. And making very little water compared to the other well, especially like the Enserch Lambirth Number 1 well, this is one of the first indications that we have of the edge water drive mechanism in the field.

Q. Let's turn to Exhibit 7. Identify this one for me, Mr. Pickett, and then describe for me what it shows.

A. This is a production plot of the Phillips Lambirth A Number 1 well. Black on this one is oil per day, the red is the water per day, and the blue is the water-oil ratio.

What I'd like to point out is, when the submersible pump was installed in this well in October of

1992, indicated on the exhibit.

Q. All right, at that point what's the approximate water cut?

A. About 87-, 88-percent water cut, or oil-water ratio in about the seven to eight range.

Q. All right. And it's within the range of the parameters of the SPE paper for a candidate for high-lift volume success?

A. That's right.

Q. All right, what happened?

A. We installed a submersible pump, and immediately thereafter the water-oil ratio started rising, indicating that we're not recovering any new reserves, the oil production goes up indicating it's an acceleration of production, but with the water-oil ratio increasing, no new reserves.

Q. By October of 1994, what's your water cut?

A. About 98 percent.

Q. And what did you do?

A. We shut the well in soon thereafter.

Q. So what does this tell you about the use of the high-lift volume system for this well?

A. You can accelerate reserves, but we didn't add any new reserves.

Q. When we look at the perforations' relationship in the A 1 well to the perfs in the Enserch well, which one has the higher perfs?

I didn't say that very well, Jack.

A. Yeah.

Q. Let me try again.

The Phillips Lambirth 1 A --

A. Yes.

Q. -- its lowest perfs are higher than the lowest perfs in the Enserch Lambirth 1, are they not?

A. Can you say that one more time?

Q. Yes, sir. If you'll look at the cross-section --

A. Okay.

Q. -- and it's a little far for me to see, but it appears, if the Phillips 1 A, its lowest perf --

A. The one on the far right?

Q. Yes, sir.

A. Yes.

Q. -- are slightly higher than the Enserch 1 A perfs in the lower portion?

A. Yes.

Q. Except this well is experiencing a higher water cut?

A. That's right.

Q. What does that tell you?

A. Edge water drive.

Q. All right, let's go to Exhibit 8. What's this?

A. This is a Phillips well test report which contains the three producing Lambirth A wells.

Q. What do you want us to see on this display?

A. The Lambirth A Number 1 well, which is the -- There's a partial well test for an unnamed well at the top, a Keystone well, and the third one down is the Lambirth A Well Number 1, the one we just talked about putting a submersible pump on.

What I wanted to show on this one is, on the far right, the fluid level of 6460 feet, which is 4000 or 5000 feet below what Enserch said they drew down their Lambirth Number 1 currently, and it's well below where our Lambirth A Number 2 is being drawn down right now.

The important thing about this one is, this well with the submersible pump was drawn down 2000 pounds, far more than any of the other two wells.

If one of the wells in the field was going to see the effect that is talked about in the SPE paper, this is the well that should have shown it. This one was pulled down harder than any of the other wells, yet we saw no effect, no positive effect, on the water-oil ratio of the water cut by installing a submersible pump.

Q. Does the SPE paper talk about adding pool reserves recovered?

A. No, it never mentions whether the reserves from a pool or a reservoir are increased. It only talks about individual wells.

Q. Exhibit 9, identify and describe that for us.

A. This is a production plot for the Phillips Lambirth A Number 2 well. Oil is the black line, water in red, and water-oil ratio in blue.

What I want to show on this one again is when we installed the submersible pump in February of 1992 on this well, the water cut was in the 86- to 88-percent range, our water-oil ratio in the 6 to 7 to 8 range, before the pump was installed, well within the SPE guidelines.

We put the pump in, the oil rate goes up, the water-oil ratio stays about the same, and then in a few months starts going up.

What I conclude from this is that, again, it was an acceleration project. We're not getting any new reserves, we didn't see any positive effect on the water-oil ratio from installing the submersible pump.

Q. Have you correctly depicted the point in the production profile of this well for the installation of the submersible pump?

A. Yes.

Q. And when we look at that point, what do we see?

A. The oil production going up and no change in the water-oil ratio immediately thereafter.

Q. Where do you get the information on when the submersible pump was installed? Is that from your own records?

A. Yes, Phillips well files.

Q. Is this information accurate and correct --

A. Yes.

Q. -- as you've displayed it here?

A. Yes.

Q. Did you and Mr. Telford back at the Examiner hearing have a difference of opinion with regards to what was happening in relationship to the installation of this pump?

A. Yes.

Q. He had shown the installation at a different point on the plot of this production profile for this well, had he not?

A. That's correct.

Q. And where had he put it?

A. At some point earlier, I don't recall where.

Q. All right. And you have gone back and rechecked, then, and you're satisfied that you have put this on the correct point --

A. Yes.

Q. -- of the production profile?

A. Yes.
Q. There's no opportunity for dispute on that issue at this hearing?
A. Right.
Q. Let's look at Exhibit 10. What is that?
A. This is a production plot for the Enserch Lambirth Number 1 well, oil in the black, the red is the GOR, and blue is the water production.
What I want to point out on this one is that essentially this well came on water-free, in 1978 it produced a little bit of water, in 1985 we're showing 10 or 20 barrels of water per day for a year or so ago, and then it produced essentially water-free again until 1993.
Q. But you're already producing water in -- what? 1980, in the A 2?
A. Yes, in the -- If we go to the next Exhibit, compare the two --
Q. Oh, am I ahead of you?
A. No.
Q. All right, let's do that. Let's compare the 10 and the 11 so that we can look at the Enserch 1, which is Exhibit 10, to the Phillips Lambirth A 2, which is Exhibit 11.
A. Yeah, I'd just like to make a comparison of these two wells. Bear in mind, they're perforated. The bottom

perforation in both these wells is at the same subsea depth.

And the Phillips well started making water almost from the very start. When the Lambirth -- the Enserch well makes its first water in 1985, 10 or 20 barrels of water per day, the Phillips well in 1985 is already up to 400 or 500 barrels of water per day.

This is another -- This is strong evidence of our edge water drive.

Q. Do you subscribe to the theory that the fractures are being depleted of oil and are now fully depleted of oil?

A. No.

Q. Why not?

A. The fractures have to be the conduit to bring the oil into the wellbore. The oil is not going to feed directly from the matrix to the wellbore. All the oil has to go through the fractures.

Q. All right. Continue then, with Exhibit 11. What else do we see?

A. Just comparison, that in 1992 or 1993 the Phillips well is up to 1000 barrels of water per day; Enserch is still water-free up to that point.

Q. All right. When we look at November of 1994 --

A. Okay.

Q. -- Mr. Burkett is telling me his well is producing about 600 barrels of oil a day, and I don't know what the corresponding water is, but they are lifting a significant amount of reservoir fluids?

A. Right.

Q. When did you shut in the Phillips Lambirth 1 A?

A. In about November of -- late October or early November of 1994.

Q. Any relationship?

A. We feel that the increased withdrawals from the Enserch Lambirth Number 1 probably did contribute to us having to shut the Lambirth A Number 1 in when we did. It probably would have gone on longer if that wouldn't have happened.

Q. Let's look at Exhibit 12. Identify and describe what you're showing.

A. This is a plot of the water-oil ratio from two of the Phillips wells, the Lambirth A Number 1 and the Phillips Lambirth A Number 2 well.

What's interesting about this plot is that whether you look at the top perforation or the bottom perforation, the Lambirth A Number 1 is higher than the Lambirth A Number 2. I think it's 12 feet above -- The Number 1 well is 12 feet above at the top and about 8 or 10 feet at the bottom perforation.

There was a -- some lower perfs open in the Lambirth A Number 1, but they were shut off in about 1982.

So the Number A Number 1 is higher than the Lambirth A Number 2 in both the top and bottom perforations, yet for the entire producing history of these two wells, the Lambirth A Number 1 has had a higher water cut, higher water-oil ratio, except for a brief six- or seven-month period in 1991. For the other 95 percent of the well's predicted life, the A 1 has had a higher cut than the A Number 2. More evidence of the edge water drive mechanism.

Q. Have you now addressed, or in part of your study did you address the recoveries that Enserch has already obtained from the Lambirth Number 1 well?

A. Yes.

Q. At the point in time that you did your calculation, what was the total cumulative recovery you were utilizing from the Lambirth well?

A. About 980,000, 950,000 barrels of oil.

Q. Mr. Burkett with his testimony has argued for the proposition that their well is not going to affect your well at higher range. Has Enserch provided testimony in the past before the Division that is evidence that leads to a contrary conclusion?

A. Yes.

Q. Let me direct your attention to what you've marked as Exhibit 13. We're looking at the portion of a transcript --

A. I'm missing half of mine.

Q. Are you?

A. Yeah.

CHAIRMAN LEMAY: I just have one page.

THE WITNESS: I've got the second page. Maybe that's all I need.

MR. KELLAHIN: Well, I'm not sure, let me hang on.

COMMISSIONER WEISS: We have different --

MR. KELLAHIN: I think what's happened is that these old -- Yeah, there's two pages to this, aren't there?

THE WITNESS: Yes.

MR. KELLAHIN: Well, how did we cleverly do that? We need both pages, don't we?

With your permission, Mr. Chairman, I'm going to hand the exhibit, the two pages, and I'm going to -- at the conclusion I would like to submit the full authentication from the transcript that will have both pages, and I will hand you my single copy of that now so that you'll have the same references as the witness.

CHAIRMAN LEMAY: Okay, thank you.

Q. (By Mr. Kellahin) All right, Mr. Pickett, I've provided you with copies of pages 21 and 22 from that Examiner hearing in which an Enserch engineer -- I believe it was Mr. Leonard Kersh --

A. Yes.

Q. -- was testifying for his company with regards to information that you have thought relevant and have utilized. What was the point of what he was doing?

A. This is testimony from the previous hearing on this field to increase the spacing from 40 to 80 acres, and the Enserch engineer is testifying about a drawdown test or reservoir-limits test that they did.

And I'll just go to the conclusion of their test, was that the Enserch Lambirth Number 1 well was affecting 830 acres, or approximately 830 acres.

Q. All right. When you take that information, what does it tell you within the context of your reservoir study and Mr. Balke's geology about the opportunity to have the Enserch well adversely affect your opportunity for remaining oil recovery if the rate is increased?

A. I guess it's a combination of them being structurally high and having good productivity. They're able to affect production for a very wide area and draw the oil out a lot faster than some of the other wells can.

Q. Have you tried to visualize or represent, at least in a hypothetical way, on Exhibit 14 an area that would include the 830 acres that Mr. Kersh had testified about being affected by the drawdown test?

A. Yes, we just drew an 830-acre are with the Lambirth Number 1 Well at the center, just to show -- graphically depict what that 830 acres looks like and how it essentially encompasses the entire productive portion of the field at the present.

Q. And that's Exhibit 14?

A. That's right.

Q. And if you were to change the shape so it matched the contours of the geology, it would encompass the entire remaining area of production in the pool?

A. Yes, because of the faulting to the south or the pinchout to the south, the reservoir is really not present where I've got the circle drawn, but...

Q. Let me direct your attention to the final exhibit, which is Exhibit 15. Does this represent your conclusions as a result of work product that you have completed using the disciplines of a reservoir engineer?

A. Yes.

Q. Describe for us what you wanted to find out, the method you used, and the results.

A. Okay. the production numbers -- this is for the Enserch Lambirth Number 1 well -- they're probably about four or five months short now, but it probably is up to a million barrels or so now. But at the time this study was done, at the middle of last year, the Enserch well had cum'd 953,000 barrels of oil, 554 million cubic feet of gas and 37,000 barrels of water.

Q. When we look at the total oil in the pool, what percentage of the total oil has Enserch already recovered from the well?

A. Enserch has recovered 38 percent of all the oil production from the South Peterson-Fusselman field.

Q. What's eight percent mean?

A. Eight percent is that one out twelve, or there's been 12 wells producing or something on that order. Essentially, they've got one out of 12 or 13 wells, whatever one-eighth -- or eight percent works out to be.

But the point of that is just, they've recovered 38 percent of the oil from only eight percent of the wells there.

Q. All right. What's the next item? What's 22 percent?

A. Looked at the percentage of the oil pay that they have in their well and compared to the total from all the other wells, and they had 22 percent of the net oil pay.

Q. They had 22 percent of the net oil pay?

A. Just in -- on a footage basis.

Q. And yet they've already recovered 38 percent of the total oil in the pool?

A. Yes. And took those net oil pays, which -- provided by geology, and just assumed that footage for 80 acres, and then took the average porosity from each well and came up with the oil in place.

Q. That's a volumetric type of calculation?

A. Exactly.

Q. And of the original oil in place, then, they have recovered, by your calculation, 20 percent?

A. Well, they have 20 percent of the original oil in place under their tract.

Q. I misspoke.

A. Right.

Q. For their 80-acre tract, based upon the calculation, they would have 20 percent of the original oil in place?

A. Right.

Q. And already, as of -- What's the date of --

A. The middle of 1994.

Q. -- the middle of 1994, they've got 38 percent of the total oil in the pool?

A. Yes.

Q. What's that tell you about correlative rights?

A. We probably have some reserves moved off -- our oil moved off the Phillips leases onto the Lambirth, Enserch Lambirth Number 1 well.

Q. And what happens if the rate is almost doubled?

A. That situation is aggravated, we lose more reserves.

Q. What would you like this Commission to do?

A. Not grant the Enserch request.

MR. KELLAHIN: That concludes my examination.

We move the introduction of Exhibits 6 through 15.

CHAIRMAN LEMAY: Without objection, Exhibits 6 through 13 or 14 will be --

MR. KELLAHIN: 15, sir.

CHAIRMAN LEMAY: -- 15, I'm sorry, will be admitted into the record.

Mr. Carr?

MR. CARR: Mr. LeMay.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Pickett, if we stay with Exhibit Number 15, I understand your testimony from this exhibit to be that somehow the correlative rights of Phillips have been impaired by the way the Lambirth Number 1 is produced?

A. You could assume that.

Q. Is that what you're saying, that correlative rights have been impaired?

A. I guess they could have been.

Q. Do you understand that in New Mexico correlative rights is defined as the opportunity to produce your fair share of the gas?

A. Yes.

Q. And do you understand you're not guaranteed anything when you drill a well but an opportunity to produce your share?

A. Right, rule of capture.

Q. You're not telling us that in the past you've not had an opportunity to produce the gas from your wells? This Commission has not denied you that opportunity?

A. Right.

Q. And the oil?

A. Right.

Q. And so what we're here today is, we're looking at what's left, where it is and how we produce what's left; isn't that fair to say?

A. Right.

Q. And we're looking at the opportunity to produce what we have today?

A. Right.

Q. And in that context, what is produced in the past isn't relevant to what our opportunity is today to produce our fair share?

A. Right.

Q. And so if we produced 90 percent in the past, we're still looking at what we've got left and what we have before us as of today and our opportunity to produce that?

A. Yes.

Q. Now, I gather from your testimony that you disagree with Mr. Burkett's conclusions about the impact that -- of the Phillips Number 2 A well on the Enserch Number 1?

A. Yes, I disagree with his conclusions.

Q. Have you done any modeling of the reservoir?

A. No.

Q. Have you attempted to calculate the impact that two wells might have on each other?

A. No.

Q. You just don't like what Mr. Burkett has done?

A. I don't think in a water drive reservoir that his calculation is relevant.

Q. But you have not made any calculation of your own to try and establish the impact between the two wells?

A. Because I don't think a calculation would be relevant.

Q. No calculation would be relevant?

A. As far as the pressure drawdown affecting updip wells.

Q. What we're talking about here is really drainage, is it not, between the two wells, the Number 1 and the 2 A?

A. Yes.

Q. And drainage is really a factor of pressure, is it not?

A. In fluid movement.

Q. And isn't fluid movement caused by pressure differential?

A. Yes.

Q. So we're talking about pressure, are we not?

A. Yes.

Q. I believe you testified that -- and would agree with us, that you're achieving a greater pressure drawdown in the 2 A than we are in the Number 1?

A. I don't think I testified to that, but I think that's correct.

Q. You attempted to --

A. It may be about equal. I --

Q. It might be about equal?

A. Yeah.

Q. You're not seeing a greater pressure drawdown in your well than what Enserch has been able to achieve?

A. I believe both wells had fluid levels in the 1500-, 1800-foot range.

Q. What was the fluid level that you -- most recent one in the Lambirth 2 A?

A. I didn't talk about it, but it's at 1830 feet from the surface.

Q. And then the Enserch Number 1, do you have a depth on that?

A. I think I wrote it down when somebody talked about it.

Q. 1320?

A. 1320, right.

Q. Wouldn't that suggest to you that you have greater pressure drawdown in your well than --

A. Yes, a --

Q. -- in the Enserch?

A. -- slightly greater pressure drawdown.

Q. I believe you told this Commission that you had attempted to install high-volume lift on wells, and you haven't seen any real response.

A. We haven't seen an increase in reserves.

Q. All right, let's take a look at your Exhibit Number 9. This is the production history on the Lambirth 2 A.

A. Okay.

Q. If we take a look at this well and we know where the submersible pump is installed in February of 1992 --

A. Yes.

Q. -- if you calculate out the remaining reserves for that well, you get a very dramatically different curve than if you calculate the remaining reserves from that well after the installation of the submersible pump; is that not correct?

A. No, that's not correct.

Q. You don't see after the submersible pump a higher curve to take that production curve on up than you do before you installed the pump?

A. It has a higher decline rate afterwards, showing its acceleration.

Q. Have you calculated those, taken those decline curves on out?

A. Yes.

Q. And you don't see any increase whatsoever?

A. No.

Q. Any competent engineer could take this and estimate for themselves the rate of decline, could they not?

A. Yes, you could come up with several different, but --

Q. Several different engineers might reach several different conclusions?

A. Right.

Q. But your conclusion is, no increase?

A. Right.

Q. Okay. I believe you testified that the A 1 has been shut in since the June hearing?

A. It was shut in, in November, and it -- I think they've turned it on a couple times for, you know, like two days in December and maybe two days in January, as sort of an experiment to see if it would make any oil.

Q. Was it your testimony that you had to shut that well in because of the increased production rate from the Enserch Lambirth A Number 1?

A. It was my testimony, I believe, that it could have caused us to shut it in --

Q. Didn't you --

A. -- earlier than we have.

Q. And didn't you -- Excuse me.

Didn't you testify in June that the well was at its economic limit, only producing until there was a pump failure?

A. Yes.

Q. If we look at the production curve on the Lambirth A Number 2, Exhibit Number 11 --

A. Okay.

Q. -- same well, and again you installed the submersible pump in February of 1992?

A. That is correct.

Q. Since that time you have seen high water cuts; is that right? Water coning?
A. I don't believe we've seen any water coning.
Q. You've seen water in the well?
A. It's making water, yes.
Q. It was your conclusion it was from a side water drive?
A. Primarily.
Q. This is the well you're pulling four times as hard as the Enserch well?
A. No, I think the -- We're not pulling it four times as hard, no.
Q. You're pulling it substantially harder, though, you've got a greater drawdown in this well than the Enserch well, we've just established that --
A. We have a greater drawdown, but it's -- I don't think it's that great.
Q. And because of the greater drawdown, you're pulling harder on the reservoir than the offsetting well?
A. Right.
Q. And it's possible that you could be pulling some water in with it because of the greater drawdown?
A. We're pulling in -- Yes, we're making more fluid.
Q. Now, I want to be sure I understood something that I discussed a few moments ago with Mr. Balke. I think

his basic testimony was that we have -- are seeing, because of high permeabilities, high drawdowns over big areas. Was that what you understood his testimony to be?

A. No.

Q. Okay. Well, let me just be sure I understand this.

Isn't it fair to say that in a reservoir of this nature, when we are looking at pressure drawdowns, generally speaking, the higher the permeability, the lower the pressure drawdown?

A. For a given rate of fluid withdrawal, right.

MR. CARR: That's all I have, thank you.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Commissioner Weiss?

I'm sorry, did you want to --

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: I didn't think so.

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. I'm confused about premature water breakthrough. These wells look like they all had premature water breakthrough back in the 1980s; is that right?

A. With the exception of the Lambirth A Number 3 and the Enserch Lambirth Number 1.

Q. And then you commented -- I sort of got this. And then let's just pick one of these. Your A 2 or A 3, how would bottom water versus edge water drive -- how would the performance here vary?

A. The -- Well, if you take a comparison between two wells, the Lambirth A Number 1 and the Lambirth A Number 2, one being ten feet higher than the other, the water cut should be higher in the lower well, and it's the reverse.

Q. Wouldn't vertical permeability enter into that?

A. I think vertical permeability is part of it, yes, is what causes the edge water drive, vertical permeability being lower than the horizontal.

Q. We don't know that, though, do we?

A. Well, I think if you -- I think that's what's going to cause the edge water drive.

Q. But given the fact that we don't know whether the vertical permeability is any different than the horizontal, I thought I heard --

A. Well, if you start off, if you think you have edge water drive, that's the only way I can explain edge water drive, is the vertical permeability is lower than the horizontal permeability.

Q. Okay. So the premise is that there's edge water drive, therefore --

A. Right.

Q. -- there's very little vertical permeability?
A. Or -- Just lower than the horizontal.
Q. Oh, and then one other thing. Does an increase in the oil cut mean increased recovery efficiency to you?
A. Not always.
COMMISSIONER WEISS: No more questions, thank you.
CHAIRMAN LEMAY: Commissioner Carlson?

EXAMINATION

BY COMMISSIONER CARLSON:

Q. What's the current allowable for the pool?
A. 267 barrels of oil a day.
Q. And you could live with that?
A. Actually, we'd like to have it reduced to 150, which is the maximum our well could make.
Q. But nobody's been able to make the allowable for many years until the Enserch Number 1 installed a submersible pump; is that correct?
A. Right.
Q. I'm looking at your Exhibit Number 11. I guess the difference between -- Well, you tell me what the difference is between your Exhibit Number 9 and your Number 11.
A. The blue scale? Well, the black scale is the same; both are oil.

Q. Uh-huh.
A. In Number 9 we're plotting in the blue water-oil ratio, and on Exhibit Number 11 the water -- it's just -- it's the water production in barrels per day.
And the red scale on the Number 11 is GOR, and the red scale on Number 9 is water --
Q. Right.
A. -- in barrels per day.
Q. And you don't think there's a marked increase in production after the submersible pump was installed?
A. Oh, I agree that, yeah, the oil has definitely gone up. But we think we're just accelerating the reserves.
Q. You said the decline rate has increased; isn't that what you said?
A. Yes. If you look previous to the submersible pump -- and you know, I know the production is quite erratic --
Q. Uh-huh.
A. -- but it's -- you know, varies, you know, varies slightly declining. But then you do see a pretty significant decline after the sub is installed.
Q. You're talking about, say -- What is that? The latter half of 1994, something in there?
A. Phillips put a larger submersible pump on the

Lambirth A Number 2, again in late 1994. That's what causes the oil production to go up again there. We put a bigger submersible pump in our well again then.

I probably should have marked that one on there too.

COMMISSIONER CARLSON: I think that's all I have.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Just one question. Do you think that the installation of a submersible pump on the Lambirth Number 1 by Enserch has affected your production to date?

A. Yes.

Q. In what way?

A. It's probably drawn in water -- or -- moving the -- more water closer to us faster.

And I know that some of the plots maybe -- not indicate it as much, but I know that in the -- but the date is fairly erratic, and I think, you know, over a long period of time, you'll see a more -- the water-oil ratio going up, or our water cut going up even faster than it was before.

Q. Do you think that's a higher -- a greater significant factor than the fact that your own submersible pumps have been pulling down the reservoir significantly, or at least producing the pressure drawdown which, as I understand it, could bring in the edge water?

A. It's definitely going to bring in -- You know, it's a function of how much oil is coming out.

And us making more oil, yes, is going to bring it in faster.

And then Enserch pulling it out is going to make it come up faster. Both would contribute to it.

CHAIRMAN LEMAY: That's all the questions I have.

THE WITNESS: Okay.

CHAIRMAN LEMAY: Thank you.

MR. KELLAHIN: That completes my presentation of Mr. --

CHAIRMAN LEMAY: Do you want to sum it up, or shall we just go with this?

MR. KELLAHIN: I want a short summary, if I might.

CHAIRMAN LEMAY: Sure.

MR. CARR: He always does. But I get to go last when he does this to me.

CHAIRMAN LEMAY: Okay.

MR. KELLAHIN: Mr. Chairman, members of the Commission, I have something that troubles me considerably, and I want to share it with you.

I'm not going to sit here and pretend as a lawyer to explain to you technical people how to handle the geology or the engineering. But I will tell you something that I am an expert in, and that is my serious concern that this Applicant has disregarded and disobeyed an order of this Division.

There is a comprehensive policy in writing from the Director that Examiner orders are effective until replaced or modified by this Commission. It is known by all lawyers that practice before this agency.

I am concerned that this Applicant goes to the District and gets permission for a test allowable, contingent upon the results of the hearing, in which Supervisor Sexton told them that after the Order was entered they were going to have to come in and account for the overproduction.

If they didn't like the Examiner Order in November, there is a comprehensive system where you ask the Examiner Order to be stayed. They didn't do that, they didn't ask for it, they didn't even call Mr. Sexton.

What do they do? They produce and continue to produce, not at 500 barrels of oil a day, but at 600 barrels of oil a day. Where is the accountability for the disregard of the orders of this Division? I can't remember an example of an applicant ever doing this before.

Their explanation? We'll just shut in and make it up, it doesn't matter.

It does matter. It matters to Mr. Pickett and it matters to Mr. Balke. If their hypothesis is correct, that increased withdrawals are going to more quickly water out their well, shutting Enserch in now has lost us an opportunity for oil recovery in the Phillips well that we cannot achieve again. The point in time is gone. And to suggest that they can be accountable by shutting it in now after ignoring the rule for months misses the point.

And you're the experts in the technical area, but I'll tell you, I am seriously concerned that an Applicant can come and do this. Shame on them.

CHAIRMAN LEMAY: Mr. Carr, would you like to sum up?

MR. CARR: That was the summary?

MR. KELLAHIN: Yes, sir.

MR. CARR: Mr. LeMay, I would agree with Mr. Kellahin that we're not engineers and geologists. I would point out in response to what Mr. Kellahin said in closing that I'm also troubled, but I'm troubled by a lawyer whose expertise is in the law, who makes a closing based on nothing that's put in the record.

We didn't hear any concern expressed by the operators of the wells in the pool, we didn't go into the details of what was or was not communicated with Mr. Sexton, and I would entrust you to look at the file, entrust this to you, look at the letter, and the letter says that this allowable level is not established on a permanent basis, that we will shut in, and I would submit to you, we're in compliance.

But I think that in fact to wait until the game is over to raise this is nothing more than after the fact trying to attack an order and a proceeding on grounds that really were never raised before, and it's nothing but an effort to deflect your attention from what's really before you.

I would point out that one time at a presentation when you and I were both on the panel, Chairman LeMay, I got in trouble with you and others for asking what was wrong with having the best well in the pool. Today I'm before you with people who have just that, who've been trying to figure out what to do with it. And we have come before you with a technical presentation that we trust you to evaluate and enter an order on the merits.

We have looked at the reservoir, we have shown you we have a fractured reservoir, we have what is basically a water-drive reservoir, a bottom water drive, Phillips says with some edge water impact. We have at this point in time, we believe, no oil-water contact because in fact the reservoir is virtually watered out, at least the fracture system.

We have differing opinions on what's going on in the reservoir. I would direct your attention to Phillips' Exhibit 5, and I trust you to determine whether or not that's an accurate depiction of what's occurring when you have the well that is on the extreme right of the exhibit drawing down the reservoir, putting pressure on the aquifer at four times the rate of the other well.

I will trust you to tell and decide whether or not this is an accurate depiction of a predominantly bottom water drive reservoir with an edge water drive component, and if that blue line that they have placed on this exhibit in fact shows how water would be migrating up into the wells. It totally disregards the bottom water drive component of this whole problem, this whole question we're wrestling with.

We've come before you today, we've presented the history of the Lambirth Number 1, we've given you an SPE paper and we've shown you that when we went out and applied this technology to this well we got the very, very results that, according to this paper, we should have expected. We've achieved exactly what they said we would, and we have a well capable of producing in excess of 500 barrels of oil a day, and that's why we need the higher allowable. And we have told you that if we don't get it, we're not going to defer but we think we will lose half a million barrels of oil.

Now, Phillips has a different view. Phillips comes in and they take Exhibit Number 9, and they say, We see no -- you'll have to not honor my doodling on it -- but they say, We see no impact, no benefit from high volume lift. Mr. Pickett can look at this exhibit and he can plot out remaining reserves, and he sees no difference.

But you see, that's why we come to a technical Commission; you can do that too. And I submit to you, when you plot the decline that that well was experiencing prior to the installation of high-volume lift, you're going to have a curve that is far below the curve that you will be able to plot after high-volume lift was installed.

And I would also submit that if you honor this data, in fact you will see that the curve is somewhat flatter, not sharper, after high-volume lift was installed. We see it, Phillips does not. But the fact is, in the final analysis, what's important is what you can see. And we submit that -- and trust you to look at this and determine whether or not in fact high-volume lift is working in the reservoir.

The question of correlative rights is a difficult one. We come before you, we argue waste, they argue correlative rights. But we have attempted to show exactly what is happening.

Now, we admit that the kind of data and information we use, the input factors need to be adjusted and that there are shortcomings, comparing the drawdown in their well with the drawdown in ours. But we have testified that the conclusion is the same, and that is, it isn't that we are going to be gaining an advantage on them, but they will maintain, albeit to a lesser extent, the advantage that they have enjoyed on us.

And it's not a question of ultimate recovery from the well; it's what they are taking now, where that pressure no-flow line happens to fall. And when you look at the record and you look at the data, I think you can clearly see that boundary falls on the Enserch tract.

The case is over, the record is before you. We believe we have shown that if you grant the Application there will be no negative impact on the correlative rights of Phillips, that the correlative rights, the opportunity afforded to Enserch to produce the reserves remaining in the matrix, those will be impaired.

We further believe that the evidence is clear, not only from what we have presented but from the Phillips Exhibit Number 9, that high-volume lift works, and by employing it in this reservoir we can recover a half a million additional barrels of oil, oil that otherwise will be lost.

CHAIRMAN LEMAY: Thank you, gentlemen, thank you for your presentations.

We'll take the case under advisement.

(Thereupon, these proceedings were concluded at 12:36 p.m.)

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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 was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

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

WITNESS MY HAND AND SEAL March 4th, 1995.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998