STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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| IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING: APPLICATIONS OF EXXON CORPORATION | CASE NOS. 11,297 11,298 (Consolidated) |

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

Volume I

June 29th, 1995

Hobbs, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MICHAEL E. STOGNER, Hearing Examiner, on Thursday and Friday, June 29th and 30th, 1995, at Hobbs City Hall, Commission Hearing Room, 300 North Turner, Hobbs, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7, State of New Mexico.

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I N D E X (Volume I)

June 29th, 1995
Examiner Hearing
CASE NOS. 11,297 and 11,298 (Consolidated)



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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 10:55 a.m.:

EXAMINER STOGNER: This hearing will come to order.

I'll call next case, Number 11,297.

MR. CARROLL: Application of Exxon Corporation for a waterflood project, qualification for the recovered oil tax rate pursuant to the "New Mexico Enhanced Oil Recovery Act" for said project, and for 18 nonstandard oil well locations, Eddy County, New Mexico.

EXAMINER STOGNER: Call for appearances in this matter.

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

I'm appearing today in association with Scott Lansdown, Counsel for Exxon Corporation.

We have three witnesses to be sworn.

And also at this time we would ask that the next case, 11,298, be consolidated with the injection Application.

EXAMINER STOGNER: Are there any objections to the consolidation of Cases 11,297 and 11,298?

Okay, at this time I'll also call Case Number 11,298.

MR. CARROLL: Application of Exxon Corporation for statutory unitization, Eddy County, New Mexico.

EXAMINER STOGNER: Call for appearances in this matter.

MR. BRUCE: Jim Bruce and Scott Lansdown again, Mr. Examiner.

EXAMINER STOGNER: Are there any other appearances in both cases, or either case?

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing this morning on behalf of Premier Oil and Gas, Inc.

We're requesting the Division to exclude from the unit the Premier Oil and Gas, Inc., leases, so we are an opponent in this case.

EXAMINER STOGNER: In both cases, I would assume, since they're consolidated?

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: Okay, any other appearances?

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

We represent Yates Petroleum Corporation in this matter.

We're appearing in support of the Applications filed by Exxon, and I have one witness.

EXAMINER STOGNER: That's Premier and Yates and

Exxon.

Are there any other appearances in this matter, or these matters?

MR. BRUCE: Mr. Examiner, I don't think there's any other appearances.

At the end of the hearing I believe there will be a couple of persons to make statements on behalf of Unit Petroleum and MWJ Producing Company.

EXAMINER STOGNER: So they will just be party of record --

MR. BRUCE: Yes, they will make a statement of record.

EXAMINER STOGNER: There being no further appearances at this time, Mr. Bruce, how many witnesses do you have?

MR. BRUCE: Three.

EXAMINER STOGNER: Will these witnesses please stand?

Mr. Kellahin, how many witnesses do you have?

MR. KELLAHIN: Potentially four, Mr. Examiner

EXAMINER STOGNER: Why don't we have all four stand to be sworn?

And Mr. Carr?

MR. CARR: I have one witness.

EXAMINER STOGNER: Will your witness please stand? Everybody remain standing at this time.

(Thereupon, the witnesses were sworn.)

EXAMINER STOGNER: Gentlemen, are there any need for opening statements, or shall we just get into the testimony?

MR. KELLAHIN: I'd like to state my position, Mr. Examiner, if it's appropriate.

EXAMINER STOGNER: Mr. Bruce, do you have any problem with this?

MR. BRUCE: I don't have any problem with it.

EXAMINER STOGNER: Mr. Kellahin, do you want to state your position?

MR. KELLAHIN: Mr. Examiner, I'm sure you'll see a unit outline map here very shortly. The proposed unit has been the subject of discussion between Ken Jones as the principal involved in Premier Oil and Gas, Inc., for some time now.

The technical work reports that Exxon has shared with us will be the subject of debate by my experts.

Our evidence will indicate to you that there is a substantial disagreement by Mr. Jones and his technical experts with regards to the allocation of hydrocarbon pore volume for the tracts that he owns and controls.

When you see the unit map, you're going to see the four 40-acre tracts that Premier has under lease, and they're stacked one on top of the other. When you look at the maps, you'll see that the east half of the east half of Section 25 are the tracts that we have in dispute.

The evidence will demonstrate to you that based upon Exxon's calculations, they have concluded that there is no primary value of Mr. Jones's tracts.

They have further concluded that there is no secondary value of his tracts.

They say if and when there is a $CO_2$ injection project, perhaps sometime in the future, they will attribute some value to his tracts.

He has a substantial difference of opinion. His experts show the distribution of hydrocarbon pore volume for his tracts show significant reserves.

There is going to be a significant dispute over log correlation. You're going to see geologists debate that issue. We believe we are correct in our interpretation.

We believe the evidence will demonstrate to you, if you believe Exxon to be correct, there's virtually no value in having our tracts in the unit.

If you believe our experts to say that we have substantial hydrocarbon pore volume value to our tracts, then there's something fatally wrong with the allocation that the Applicant has asked for, and it either needs to be redistributed so that we get our relative value share under statutory unitization.

We think that the most convenient solution, as our experts will provide to you, is to simply exclude our tracts. And that's why we're here.

EXAMINER STOGNER: Mr. Kellahin.

Any other further comments at this time?

Mr. Carr?

MR. CARR: No, Mr. Stogner.

EXAMINER STOGNER: Mr. Bruce?

MR. BRUCE: I would simply say, Mr. Examiner, that we believe the evidence will prove that Exxon's log correlations and its geological interpretations are the correct ones.

We point out that Premier's acreage has produced only 5000 barrels of primary oil, and we will further prove that Premier's tracts are necessary for the proper development of this unit, and we will go into this in our direct case.

EXAMINER STOGNER: Thank you, Mr. Bruce.

With that, I assume we'll get started with the direct testimony of Exxon at this time.

MR. BRUCE: Okay.

EXAMINER STOGNER: Mr. Bruce?

MR. BRUCE: First we'll present our land

testimony, Mr. Examiner.

JOE B. THOMAS,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name and city of residence for the record?

A. My name is Joe B. Thomas. I live in Midland, Texas.

Q. And what is your occupation and who are you employed by?

A. I'm a landman employed by Exxon Corporation.

Q. Have you previously testified before the OCD as a landman?

A. Yes.

Q. And were your credentials as an expert petroleum landman accepted as a matter of record?

A. Yes.

Q. Finally, are you familiar with the land matters involved in these Applications?

A. Yes.

MR. BRUCE: Mr. Examiner, I would tender Mr. Thomas as an expert petroleum landman.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: No objection, Mr. Thomas is so qualified.

Q. (By Mr. Bruce) Mr. Thomas, would you briefly summarize what Exxon seeks in these two cases?

A. In Case Number 11,298 Exxon seeks to statutorily unitize all interests in the Delaware formation underlying all or parts of nine sections of land, which is described on Exhibit 1.

The unit area covers 2118.78 acres and is comprised of federal acreage, 711.87 acres, for 36.43 percent.

State acreage is 1146.91 acres, or 54.13 percent.

And fee lands is 200 acres, or 9.44 percent.

Do you want me to repeat those percentages?

EXAMINER STOGNER: Are they written down somewhere?

THE WITNESS: I don't believe -- Yes, they are, on Exhibit B to the unit agreement.

EXAMINER STOGNER: If they're written down, there's no need to repeat them.

THE WITNESS: Okay. In Case Number 11,298, Exxon seeks approval of a secondary-recovery waterflood project for this unit and the certification of project for recovered oil tax rate.

Q. (By Mr. Bruce) What is the proposed injection interval?

A. The intervals in which we plan to inject water are the Cherry Canyon and Brushy Canyon zones.

The unitized formation is the interval from 100 feet above the base of the Goat Seep Reef to the top of the Bone Springs formation, as found in the Exxon Yates "C" Federal Well Number 36, located at 1305 feet from the north and east lines of Section 31, Township 20 South, Range 28 East, Eddy County, New Mexico.

The unitized formation will include all subsurface points throughout the area correlative to these depths.

Q. Now, you've already identified Exhibit 1, the land plat. Would you describe its contents a little further for the Examiner?

A. Yes, the land plat outlines the proposed unit area, which identifies the separate tracts which comprise the unit area. The tracts are formed according to common mineral ownership.

There are 12 tracts in the unit area. Exxon operates five of these tracts, Yates Petroleum Corporation operates 5, MWJ Operating operates one tract, and Premier operates one tract.

Q. Will you move on to your Exhibit 2, Mr. Thomas, and identify it for the Examiner?

A. Exhibit 2 is the proposed unit agreement. The unit agreement is a standard form, except for a few minor revisions which were previously approved by the BLM and the Commissioner of Public Lands, and similar to the ones approved previously by the Division.

The unit agreement describes the unit area and the unitized formation. The unitized substances include all oil and gas produced from the unitized formation. The designated unit operator is Exxon Corporation.

Q. What about Exhibit 3? What is that?

A. I'm sorry?

Q. Exhibit 3.

A. Exhibit 3 is the proposed unit operating agreement which sets forth the authorities and duties of the unit operator, as well as the apportionment of expenses between the working interest owners.

Q. Does the unit operating agreement contain a provision for carrying working interest owners?

A. Yes, in Section 12.

Q. And does it also provide for a penalty against nonconsenting working interest owners?

A. Yes, Section 12 provides for a 200-percent nonconsent penalty.

Q. From a landman's standpoint, is this a fair penalty?

A. Yes, it is.

Q. And why is that?

A. Operating agreements in this area typically provide for similar nonconsent penalties.

Q. Some operating agreements even provide for higher penalties?

A. That's correct.

Q. Now let's get on to the ownership of tracts in the unit area.

Would you please describe the tract ownership and how you determined the names of the working interests and the royalty owners within the unit area? And at this point, I think we need to refer back to Exhibit 2.

A. Okay, we need to go back to Exhibit 2. It's the backup to Exhibit 2, it's Exhibit "B" to Exhibit 2.

Exhibit "B", which -- the unit agreement, is a tract-by-tract listing of the interest owners. These names and interests were obtained from current Division orders or title opinions on the files on the tracts that Exxon operates.

On the tracts operated by other parties, we based ownership based on information obtained from the other operators' files.

Q. And how many interest owners are there in the proposed unit?

A. There are 48 working interest owners and 24 royalty or overriding royalty interest owners.

Q. Let's talk first about the working interest owners. Who are they and who do you seek to statutorily unitize?

A. Exhibit 4 lists all the working interest owners in the unit and contains working interest owner ratifications. The only working interest owners who have not yet ratified are shown in Exhibit 4-A, which will be passed out to you.

We seek to statutorily unitize these owners.

Q. And what is the total percentage by participation of the nonconsenting working interest owners?

A. 2.492211 percent. Now, this includes parties that have said they're going to execute the agreement but haven't gotten to me yet, haven't got it in to me yet.

Q. Such as Devon Energy --

A. Such as Devon and Hayes Partners.

Q. Okay. And if these parties subsequently submit their ratifications to Exxon, they will be deemed to be ratified or consented to the unit?

A. That's correct.

Q. Now, let's move on to the royalty owners. Would you identify your Exhibit 4 and discuss the working interest -- or, excuse me, the royalty interest owner participation?

A. I think that's Exhibit 5.

Q. Or Exhibit 5, excuse me.

A. Exhibit 5 lists all the royalty interest owners. It contains royalty owner ratifications.

Mr. Bruce is handing out Exhibit 5-A.

The royalty and overriding royalty owners we seek who have not yet ratified the unit are shown in Exhibit 5-A, and these are four parties: Robert L. Hayne and Sue Hayne, Oryx Energy Company, Sabine Royalty Trust, and Peggy A. Yates Estate.

Peggy A. Yates Estate was inadvertently left out of the Yates group of ratifications, and it's forthcoming.

Q. Now, on both your Exhibits 4 and 5, in addition to listing the interest owners, it also contained copies of all the ratifications received to date; is that correct?

A. That is correct.

Q. Now, as you've indicated, there's quite a bit of state and federal land in this unit. Have the Bureau of Land Management and the Commissioner of Public Lands preliminarily approved the unitization?

A. Yes, Exhibits 6-A and 6-B contain copies of the BLM and Commissioner's letters of designation for this unit. Their final approval is conditioned on OCD approval of the unit.

Q. Now, looking at the ratifications received to date, what percentage of working interest and what percentage of royalty owners have voluntarily agreed to join in the proposed Avalon-Delaware unit?

A. Approximately 97.5 percent of cost-bearing working interest owners have ratified the unit agreement and unit operating agreement.

Twenty out of 24 of the total number of the royalty or overriding royalty interest owners have ratified the unit agreement, which is about 95-percent-plus, based on participation, or 83 1/3 based on the number basis.

Again, we're counting the interest of Peggy A. Yates Estate as not ratified, but it will be forthcoming.

Q. Would you please discuss Exxon's efforts to obtain voluntary unitization among the parties to the unit? And I'd refer you to Exhibit 7. Would you please identify that?

A. All right, Exhibit 7 contains copies of correspondence regarding the unit.

The first three pages are a summary or table of contents of the letters.

Q. And the remainder is just copies of all the correspondence?

A. Copies of the correspondence, the letters.

Q. Would you -- Rather than going through document by document, would you outline Exxon's contacts with the interest owners?

A. Okay. Exxon first began considering unitization of Avalon-Delaware Pool in 1991 and had informal discussions with working interest owners, starting shortly thereafter. Exxon also began collecting data for the preparation of the technical report at that time.

The first contact with working interest owners formally proposing an enhanced recovery unit was by letter dated March 9th, 1992, when Exxon sent the working interest owners the proposed pre-unitization voting procedure.

This letter also proposed unit boundaries, and these unit boundaries have not changed since 1991.

In August of 1992, the technical report was completed and made available to working interest owners.

In the fall of 1992, Yates wrote to Exxon outlining certain issues and concerns. As a result, Exxon and Yates representatives met on December 9th, 1992, and the results of this meeting were conveyed by Yates by letter to Coquina. Coquina's interest is now owned by Unit Petroleum.

Because there appeared to be a general consensus on unitization, Exxon met with representatives of the BLM in Carlsbad and the OCD at Artesia on February 1st, 1993, and with the SLO and the OCD in Santa Fe on February 2nd, 1993. The SLO and the BLM are the largest royalty interest owners.

Certain parts of the technical report were subsequently added, and Exxon forwarded ballots to the working interest owners for their review and approval. Over 90 percent of the working interest owners approved the amendment to the technical report.

In January, 1994, Exxon requested title data from working interest owners so they could proceed with preparation of exhibits to the unit agreement.

I should note that throughout this period and up until June, 1995, there have been numerous telephone calls between Exxon personnel and personnel from the other working interest owners.

On April 8th, 1994, Exxon notified working interest owners that the technical report was approved and scheduled a working interest owners' meeting on April 26th, 1994.

As a result of verbal and written comments, Exxon scheduled another meeting on June 17th, 1994, at which over 90 percent of the working interest owners were represented.

Comments were made and concerns expressed by Premier, Yates, Hudson and ANPC, whose interest is now owned by Unit, regarding the participation formula, voting percentages and other matters.

The working interest owners, including Exxon, asked Yates to take the lead in developing and proposing a single-phase participation formula.

Yates developed several single-phase formulas which they discussed with Exxon during the next several months.

As a result of these discussions, Exxon and Yates agreed to present the single-phase formula to the other working interest owners.

On February 22nd, 1995, Exxon sent the working interest owners a letter making certain revisions to the unit agreement and the unit operating agreement and proposing the single-phase formula, as set forth in Exhibit 2, which is the unit agreement which has been submitted already. A nonbinding ballot on unitization was approved by 97.4 percent of the working interest owners.

The unit documents were revised, and on May 1st, 1995, the unit agreement was mailed to fee royalty owners.

Exxon met with the BLM again on May 2nd, 1995, and with the SLO on May 5th, 1995. Both agencies expressed their support of unitization, and Applications were filed with the OCD on May 9th, 1995.

Final copies of pertinent unit documents together with ratification forms were sent to all interest owners on

May 12th, 1995.

Q. Were there any changes subsequently made to the unit agreement?

A. Yes, there were. BLM and SLO made corrections to acreage figures which we had used, and we corrected spelling and typographic errors.

This resulted in new Exhibits "A" and "B" to the unit agreement, which were mailed to interest owners on June 12th, 1995.

Q. Did any of these corrections change the terms of the unit agreement or change any unit participations?

A. No.

Q. Were there any unlocatable interest owners?

A. No.

Q. Has Exxon, in your opinion, made a good-faith effort to secure voluntary unitization?

A. Yes.

Q. Has written notice of the unitization hearing been given to all the parties who did not voluntarily join in the unit?

A. Yes, copies of the notice letter and certified return receipts are attached to an affidavit regarding notice, which is submitted as Exhibit 8.

Q. Okay. Now, regarding the waterflood project, Case 11,297, was notice of that hearing given to all proper parties as required by the form C-108?

A. Yes, Exhibit 9 is my affidavit concerning the notice letter sent to surface owners and well operators, together with certified return receipts.

Q. In your opinion, will the granting of these Applications be in the interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. And were Exhibits 1 through 9 prepared by you or under your direction or compiled from company records?

A. Yes, they were.

MR. BRUCE: Mr. Examiner, at this time I'd move the admission of Exxon Exhibits 1 through 9.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Exhibits 1 through 9 will be admitted into evidence at this time.

MR. BRUCE: I have no questions of the witness at this time.

EXAMINER STOGNER: Thank you, Mr. Bruce.

Mr. Kellahin?

MR. KELLAHIN: Mr. Carr?

MR. CARR: I have no questions.

MR. KELLAHIN: Thank you, Mr. Examiner.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Thomas, if you'll take the unit map, which is Exxon Exhibit 1 --

A. Yes, sir.

Q. -- Section 31 is designated as Tract Number 2?

A. That's correct.

Q. And that is a tract operated by Exxon?

A. That's correct.

Q. Exxon's percentage in the unit on an acreage basis is more than 70 percent, is it not?

A. That's correct.

Q. It's about 73 percent, I think?

A. It's approximately -- About that, yes.

Q. All right. So Exxon by itself cannot ask the Division to use statutory unitization to bring in the remaining parties unless you get the cooperation of another working interest owner; isn't that true?

A. That's correct.

Q. And to meet the minimum 75 percent of the working interest owners, you achieve that when Yates signs on to the deal?

A. That is correct.

Q. And what percentage of the unit does Yates have?

A. Approximately 12 percent.

Q. So if you and Yates agree on all decisions in the unit, then you'll make the minimum 75-percent required to go forward under statutory unitization?

A. That is correct.

Q. When we look at Exhibit 1, where are the Yates-operated tracts?

A. They're to the north of Section 31, Section 29 and 30, of 20 South, Range 28 East, and also Tract 7, which is in Section 36 of 20 South, Range 27 East.

Q. All right. Principally, they're in Section 30 with the Tract 5 and the Tract 3?

A. Three, 4 and 5.

Q. Okay. When you look at the east half of the east half of 25, Tract Number 6 --

A. That's correct.

Q. -- who is the operator of those tracts?

A. Premier.

Q. Has your involvement as a landman in the unitization process been from the inception of the process?

A. That's correct.

Q. Do you know when the technical committee completed their report?

A. An exact date?

Q. Yes, sir.

A. No, I don't recall the date. It was in 1991.

Q. The copy of my -- My copy of the technical report says August of 1992. Do you see that?
A. Okay.
Q. Are you familiar with this technical report?
A. Yes, I am. I've read it.
Q. Is this the only technical report there is?
A. As far as I know, yes, sir, that's the only technical report.
Q. And this is the final technical report, if you will?
A. There have been amendments sent out to that, yes.
Q. But this is the basic document that was generated by the technical committee?
A. That is correct.
Q. Does this technical committee that generated this technical report consist only of Exxon personnel?
A. Yes, the working interest owners asked Exxon to be the technical committee.
Q. And so none of the other working interest owners had technical representatives on the technical committee?
A. I'm not aware of that. I'm sorry, I can't answer that.
Q. Do you know if Premier was invited to put a technical member on the technical committee?
A. No, I don't know the answer to that either, sir.

Q. Okay. Was Yates invited to do that?
A. It's my understanding that all the working interest owners originally asked Exxon to be the technical committee, and I don't know at that time if Premier was included in that group, but I feel sure it was.
Q. By August of 1992, then, we have the technical committee report?
A. That is correct.
Q. Does the boundary used by the working interest owner group, as of August of 1992, on through the present, conform to the boundary that we're seeing before us today in Exhibit 1?
A. Yes, sir.
Q. When we look at Exhibit 2, which is the proposed unit operating agreement, we turn over to page 7 of the operating agreement and we have the tract participation formula, don't we?
A. That's correct.
Q. Now, this is the final formula that was initiated, I guess, by Yates, and finally agreed to by Exxon?
A. That's correct.
Q. It's a single-phase formula?
A. That is correct.
Q. You credit 25 percent to the remaining primary

recovery for a tract, 50 percent to the waterflood oil recovery potential for that tract, and then 25 percent for any oil to be attributed to the $CO_2$ recovery?

A. That is correct.

Q. That's how it's put together, isn't it?

A. That's correct.

Q. When we turn to the Exhibit C to Exhibit Number 2, then we can see the input of that formula and an allocation back to each tract; is that not true?

A. That is correct.

Q. And when we read down, we find Tract 2 where Exxon is the operator -- it's the second row down -- and about 53.87 percent of the tract participation is valued in that tract?

A. That is correct.

Q. When we get down to Tract 6, which is the Premier tract, they've got one percent?

A. That is correct.

Q. All right. And when we turn over, then --

A. Now, that's tract participation in the unit.

Q. Yes, sir. When you look over at Exhibit "D", now, this shows for Tract 6, when you read down and find the row that has Tract 6, you read across and it says the remaining primary reserves attributable to the Premier Tract, Number 6, is zero.

A. It's also 5-F and 7 and 8 -- I'm sorry, 7. Six and 7.

Q. Yes, sir. The one I'm concerned about is 6.

A. Right.

Q. And as you read across to see the waterflood reserve, it's also zeroed out, isn't it?

A. That is correct.

Q. And the only time that this tract has been credited with any reserve potential is in the $CO_2$ thick?

A. That is correct.

Q. And they're credited with -- What? $1.6 million, is it?

A. That's correct.

Q. Is that a recoverable reserve number?

A. I don't know the answer to that question.

Q. This vertical unitized interval is from -- you said the base of the Goat Seep --

A. A hundred feet above the base of the Goat Seep.

Q. A hundred feet above the base of the Goat Seep. And it goes down to the top of the Bone Springs, was it?

A. That's correct.

Q. That would then geologically correspond to the Cherry Canyon, you have the Brushy Canyon. Is that also inclusive of the Bell Canyon?

A. I think you're going to have to ask the geological witness for that, sir.

Q. But for your work purposes, that's the interval that is defined in all these documents?

A. That is correct.

Q. What is your understanding of the primary objective of the unit?

A. To produce additional oil.

Q. Under the waterflood phase, wasn't it?

A. That's correct.

Q. Okay.

A. And possible $CO_2$ flood.

Q. Why did you use the word "possible"?

A. Because at this point we can't determine -- can't make the statement, direct statement, that we're going to do a $CO_2$ flood.

Q. When you look at the package of documents, was this 7?

A. That's correct.

Q. All the correspondence is 7?

A. If it had a big binder clip around it, that's all 7.

Q. Yes, sir, that's right. And it's in here chronologically?

A. Yes, sir.

Q. If you'll go through the pile with me, and let's find the Exxon-generated letter of October 10th, 1994. It's about, I guess, two-thirds of the way down through the pile.

A. Okay, is this the letter to Dave Boneau?

Q. Yes, it is. It's dated October 10th, it's on Exxon letterhead. It's signed off by Ron Mayhew as Exxon's Avalon Project Manager, and this is written to Dave Boneau. And this is part of the correspondence package?

A. That is correct.

Q. When you look at the second paragraph down and find the second sentence it says, "The waterflood is the reason the Unit has value to all of us and your representation of Phase 1 would be acceptable to us for the waterflood." It says, "The $CO_2$ flood has some probability of happening/not happening and your representation of Phase 2 is acceptable if a $CO_2$ flood is in the future for Avalon."

During October of 1994, the discussion is whether to go with a two-phase formula or a single-phase formula; is that not true?

A. That is correct.

Q. But under either formula, the primary objective was the waterflood portion of the project?

A. The waterflood and possible $CO_2$ flood.

Q. If the primary objective of the unit is to have a waterflood project that has value to all of us, show me how there is any value attributed to Premier when I look at Exhibit D to Number 2, the Unit agreement, and there is no value attributed to the waterflood.

MR. BRUCE: Mr. Examiner, I'd object. He's asking, I think, engineering questions about the relative value of tracts.

MR. KELLAHIN: I'm not sure yet, Mr. Examiner. Let me try again. I'll rephrase the question.

EXAMINER STOGNER: Please do.

Q. (By Mr. Kellahin) When I look at Exhibit D, which is the attachment to the unit agreement marked as Exxon Exhibit 2 --

A. Right.

Q. -- and I'm looking down the spreadsheet for Mr. Jones's tract, Premier's Tract Number 6, and I read across and I see zero reserves -- Okay?

A. That's correct.

Q. -- and then I come to Mr. Mayhew's correspondence in October 10th of 1994, and he's telling us all tracts have value as to waterflood, that's not correct, is it?

A. It's correct in that the unit is a waterflood with a possible $CO_2$ flood. The value is in both of them together.

Q. If you'll turn with me, sir, to Exhibit 7, which is the package of correspondence, and let's come back just a few sheets from the October 10th, 1994, letter, and let's look at the package that's also on Exxon's letterhead, it's got a date of June 20th of 1994, and right under that it says June 17th Meeting Notes.

A. Right, okay.

Q. It shows a rubber date stamp on the face of the letter, it says June 22nd, 1994. Do you know what that means? Whose date stamp is on this copy?

A. I'm sorry, which one are you --

MR. KELLAHIN: If I may approach the witness, Mr. Examiner, let me ask him what this means.

EXAMINER STOGNER: Please do.

Q. (By Mr. Kellahin) Are we looking at the same sheet here?

A. Oh, this sheet, okay?

Q. All right.

A. This one.

Q. Yes, sir.

A. Okay.

Q. Now, this is a letter over Mr. Mayhew's signature, and mine is all stapled together with a bunch of other stuff.

A. Right.

Q. Why is that all stapled together like that?

A. These were enclosures to the letter.

Q. Is that something you know about?

A. I mailed it out.

Q. Okay. Was there a June 17th meeting on the Avalon field?

A. That is correct.

Q. It says June 17th Meeting Notes. Where did that occur?

A. In Exxon's office in Midland, Texas.

Q. And were you present there?

A. That's correct.

Q. When you thumb back through these pages of attachments to this letter, let me have you find this spreadsheet that reads horizontally, "Avalon Working Interest Owners Meeting Summary."

When you look at the first entry on the spreadsheet that we're looking at, Mr. Thomas, is this an accurate summary of the working interest owner meeting when it reads, "Issue: Withdrawal from Unit. Premier disagrees with other working interest reservoir interpretations. Solution: Remap unit boundaries to exclude Premier's acreage [all agree]"?

A. That's correct.

MR. KELLAHIN: No further questions.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Carr, any cross-examination?

MR. CARR: No questions, Mr. Stogner.

EXAMINER STOGNER: Any redirect, Mr. Bruce?

MR. BRUCE: Just a couple, Mr. Examiner.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. One question was about Yates owning 12 percent of unit participation.

Mr. Thomas, referring to your Exhibit 2, the unit agreement, and Exhibit B, actually that 12 percent isn't one -- It's not Yates Petroleum, is it, who owns 12 percent?

A. No, it's all Yates' interest.

Q. There's a number of people on that Yates Petroleum, Abo, individual Yates family members, Yates estates, et cetera.

A. That is correct.

Q. Okay. Now, Mr. Kellahin asked you a couple of questions about the unit boundary. The unit boundary was initially Exhibit 1. That's the same unit boundary as was initially proposed in 1991; is that correct?

A. That is correct.

Q. Okay. And if you keep Exhibit 2 in front of you, Exhibit "D", there are a number of tracts that have no primary and/or secondary reserves attributed to them; is that correct?

A. That is correct.

Q. So it doesn't only affect Premier; is that -- ?

A. That is correct.

Q. There are Yates and other tracts in there that have zero secondary and primary reserves attributed to them?

A. That is correct.

MR. BRUCE: Okay. I have nothing further, Mr. Examiner.

EXAMINER STOGNER: I don't have any questions of this witness at this time either. He may be excused at this time.

What is your next witness?

MR. BRUCE: Our next witness is a geologist, and he -- Direct exam plus cross-exam will probably take a fair amount of time.

I think it might be best to break for an early lunch and -- I've probably got 40 to 45 minutes of direct.

EXAMINER STOGNER: I think this might be a good time to take a lunch break.

What do you say we reconvene here in about an hour? So that would be about 12:40, and we'll start up at that time.

(Thereupon, a recess was taken at 11:35 a.m.)

(The following proceedings had at 1:00 p.m.)

EXAMINER STOGNER: Hearing will come to order for the consolidation of Cases 11,297 and 11,298.

Mr. Bruce?

MR. BRUCE: Commence with our geologic testimony, Mr. Examiner.

DAVID L. CANTRELL,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Cantrell, would you please state your full name and city of residence?

A. I'm Dave Cantrell from Houston, Texas.

Q. Who are you employed by and in what capacity?

A. I'm a geologist with Exxon Corporation.

Q. Have you previously testified before the Division?

A. No, I haven't.

Q. Would you please describe your educational and employment background?

A. I hold bachelor's and master's degrees in geology from the University of Tennessee and have been employed by Exxon for a little over 13 years now.

For the first seven years of my career with Exxon

I conducted reservoir characterization studies and research on several large Middle Eastern and South American oilfields.

I moved to Midland, Texas, in 1989 and for five years conducted field studies on fields in the Permian Basin area and in the Rocky Mountain area.

Since 1994 I've been in Houston and continue to be responsible for the Avalon-Delaware field.

Q. Would you please describe your geologic work on the proposed Avalon Delaware unit?

A. I've worked on the Avalon Delaware Pool since 1990 and have completed an integrated reservoir study evaluating reservoir architecture and quality for this field.

For this evaluation I, along with other Exxon geoscientists, identified key stratigraphic surfaces that control reservoir geometry, evaluated rock quality as it relates to production, reviewed all available log data, calculated fluid saturations and volumetrics and mapped the distribution of the reservoir.

Q. And based on that study, have you prepared certain exhibits for presentation today?

A. Yes, I have. If you'll refer to Exhibit 10, which is a --

MR. BRUCE: Well, just a minute, Mr. Cantrell.

Mr. Examiner, I would tender Mr. Cantrell as an expert petroleum geologist.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Mr. Cantrell is so qualified.

Q. (By Mr. Bruce) Okay, Mr. Cantrell, let's move on now to your Exhibit 10. Would you identify that for the Examiner?

A. Okay. Exhibit 10 is the large two-volume report that details the results of a technical study conducted by Exxon on Avalon.

Volume I of this report, a sort of a thick 8-1/2-by-11-inch document that you have, labeled "Text and Exhibits", consists of several sections, beginning first off with a summary and recommendation section that summarize the major aspects of the project, followed by an introduction to and overview of the field.

The next three sections -- And let me preface this by saying, each of these sections has a number of parts. Typically there's first a text section and then a list of exhibits or an exhibit section, and then typically a series of appendices afterwards.

But the next three sections after the first ones that I just mentioned detail the results of the geologic work that's being completed as part of this study.

The first section, labeled "Stratigraphy", details the results of our effort to define the reservoir architecture and geometry of the field.

The next section, labeled "Formation Evaluation", details the results of our assessment of reservoir quality and fluid saturations.

Finally, the section labeled "Mapping and Volumetrics" shows the results of our efforts to map out the reservoir distribution and calculate volumetrics.

The next three sections in this report following this, then, detail the results of the engineering work and focus first off on the simulation work, next on the generation of project flow streams, and finally on the economics for the project.

The last section of this Volume I summarizes some of the maps that were generated as part of this study.

Volume II is the larger 11-by-17 folio that you have, and it includes both maps and cross-sections in here. The maps that you see here are simply larger versions, larger-scale versions of the maps that are summarized in Volume I.

I assisted in the preparation of this study, as did Mr. Beuhler, our next witness.

Q. Would you then move on to your Exhibits 11 and 12 together and describe the work done by you to create the geologic model of the Avalon Pool?

A. Exhibit 11 summarizes the overall geology of the Avalon area.

As can be seen in the index map in the upper left-hand portion of this exhibit, geologically Avalon is located on the northwestern margin of the Delaware Basin in a very proximal basin margin setting immediately seaward of the shelf edge. The location of Avalon is noted in red on this index map.

As the idealized stratigraphic section in the upper right-hand part of this exhibit shows, Avalon produces from fine sands and coarse siltstones of the Permian-age Delaware Mountain Group. And it's underlain by tight carbonates of the Bone Spring formation and overlain by tight carbonates, generally tight carbonates, of the Goat Seep Reef.

As you can see in this area, the Delaware Mountain Group consists of only two formations: the Brushy Canyon formation and the Cherry Canyon formation. No Bell Canyon formation occurs at this location in the Basin.

Now there are two major productive intervals in the Delaware Mountain Group, and I've tried to highlight those or shade those in, in this idealized stratigraphic section here.

There's an upper section which I've shaded in a kind of a reddish color there, in the Upper Cherry Canyon. There's also a lower productive interval at the top of the Brushy Canyon formation, including a small slice of the Lower Cherry Canyon as well, and I've shaded this interval in brown.

The data block at the bottom of this exhibit gives you a summary of some of the reservoir description parameters for this field.

Starting off first with the upper reservoir, the Upper Cherry Canyon, it occurs at approximately 2600 feet. It's comprised typically of very fine-grain sand in terms of a reservoir lithology, has an average net thickness of 131 feet, an average porosity of 14.4 percent and an average permeability of 2.3 millidarcies.

Oil in place, or oil originally in place, is calculated to be 107 million barrels for this upper reservoir.

The lower reservoir, this Upper Brushy Canyon reservoir, occurs at a depth of about 3400 feet, is comprised dominantly of a coarse siltstone but it includes some fine sand as well, has an average net thickness of 272 feet, an average porosity of 14.9 percent and an average permeability of 1.1 millidarcies.

Oil originally in place is calculated to be 141 million barrels for this reservoir.

All completions in both of these reservoirs are proppant frac'd -- fractured.

Exhibit 12, the next exhibit, summarizes the regional stratigraphy of the Delaware Basin margin and shows how we utilized a regional framework in describing the reservoir architecture of the Avalon field area.

Now, Avalon again is shown in the index map in the upper left-hand corner of this exhibit, and it's indicated in red.

In this area, in this part of southeastern New Mexico and western Texas, several groups from both oil industry -- various groups in oil industry as well as from various academic institutions have completed regional stratigraphic studies that we've used in establishing the reservoir stratigraphic framework at Avalon.

These groups have extensively studied outcrops in the area, especially Delaware-age outcrops -- if you'll look at the index map down in sort of the lower left-hand corner, in the Delaware mountains there, about 60 miles along strike from Avalon field, as I said, in the Delaware Mountains, as well as along the western escarpment of the Guadalupe Mountains.

In addition to that regional outcrop work, there's also a published seismic line, located -- a regional seismic line, located just about six miles to the north or northeast of Avalon field.

Now, using all of this regional data from both the outcrop as well as regional seismic data, as well as including local information at Avalon -- and I've summarized most of the database that we had for doing this, in that data block in the upper right-hand portion of this exhibit -- using all this information and including local information at Avalon, we've developed a stratigraphic framework that we believe successfully resolves reservoir architecture and geometry at Avalon.

This stratigraphic framework, then, that we've developed is summarized in the cross-section shown at the bottom of this exhibit, and this is again a dip cross-section, oriented northwest to southeast, and I've annotated on this cross-section the location of Avalon field. I've also tried to shade in on this cross-section the approximate locations of the two major productive intervals we described earlier in the Upper Cherry Canyon and the Upper Brushy Canyon.

Three surfaces on this exhibit, on this cross-section, are especially significant, and I'll try to describe them to you from the bottom up.

If you'll look at sort of the lower middle portion of the exhibit, there's a surface which I've shaded in brown at the top of the Upper Brushy Canyon reservoir.

Moving on up, there's a surface which I've shaded or colored green at the top of the upper Cherry Canyon reservoir.

And finally, on up just a little bit beyond that, I've shaded another surface or colored another surface as a sort of a red squiggly line. This in the Avalon field area is the base of the Goat Seep Reef. You notice how this red squiggly line actually, as it comes down off the shelf and plunges into the Basin, actually erodes away a portion of the green surface we mentioned a minute ago.

Since these surfaces are typically capped by shales and/or tight carbonates, they describe the top seals for the two reservoirs and thus control production. These surfaces provided the basis for some of the mapping I'll show you in a moment.

Q. Do you need to look at the geology on a regional basis to make a correct determination, rather than just a few wells in a localized area?

A. Yes, you need to look at the geology on a regional basis.

In order to fully understand the distribution of the reservoir and where oil occurs in the subsurface, you first have to understand or get a good handle on stratal geometries and stacking patterns that occur in the reservoir, subsurface.

For this, you need to know a couple of things. You need to have a good understanding of regional depositional patterns and trends which are best seen, as we've seen earlier, on this regional outcrop work and regional seismic data.

In addition, examination of outcrops reveals stratigraphic and rock-fabric details that enhance your understanding of the rocks and enhance your understanding of the situation, as well as your ability to interpret log patterns in the subsurface.

Q. What about examining well logs in a particular area, localized area? What do they tell you?

A. Well, well logs are valuable information for correlation purposes, but really only show you a small slice or sample through the reservoir. Most wireline logs only read from a few inches to a few feet out into the reservoir.

So the picture you get from well logs alone is one of limited slices or samples distributed across the reservoir. And in the case of Avalon, these slices or samples are located 40 acres apart, 1320 feet apart.

So in order to do the best possible job that you can of describing the reservoir, you really need to know additional information from the regional picture, as well as from the outcrop work.

Q. Well, could you show us what the stratigraphic framework looks like in an Avalon-Delaware well?

A. Yes, please refer to Exhibit 13, which is a type log from Exxon's Yates "C" Federal Number 36. Joe Thomas has described this well previously. This well is located in Section 31 of Township 20 South, Range 28 East.

And it shows these surfaces that we identified earlier on Exhibit 12, and you can see we've tried to use the same color scheme that we showed previously, the brown surface being the top of the Upper Brushy and the Lower Cherry Canyon reservoir, the green surface being the top of the Upper Cherry Canyon Reservoir, and the red being the base of the Goat Seep Reef.

So it shows these same surfaces that we've identified earlier, as well as the intervals in which we plan to inject water in the Delaware reservoir intervals.

The proposed unitized interval includes all subsurface points throughout the unit area correlative to the Delaware Mountain Group in this well.

Q. Are the Upper Brushy Canyon and the Upper Cherry Canyon reservoir intervals similar or different?

A. Our study of Avalon indicates that there are major differences in reservoir architecture between these two reservoirs.

Q. Could you describe these differences, please?

A. Yes, please refer to Exhibit 14. Exhibit 14 is a schematic cross-section of the Brushy Canyon formation, showing that this reservoir, which I've shaded in yellow at the top of the exhibit there -- showing that this reservoir is an anticline which dips away in both directions from a structural crest at the center of the exhibit.

As this exhibit dramatizes, this anticlinal structure is really built, if you will, by depositional mounding in units underlying the Upper Brushy and Lower Cherry Canyon reservoir interval, starting, if you'll look at the bottom of the exhibit, starting from a -- with a fairly flat generally eastward-dipping surface at the top of the Bone Spring formation, and through Lower and Middle Brushy Canyon time, if you will, building up a depositional mound with significant structural relief.

The reservoir interval, then, on top of all this simply drapes over this older mounding in the deeper unit.

Exhibit 15 is a schematic cross-section of the Upper Cherry Canyon and dramatizes the more complex nature of this reservoir.

Following Lower Cherry Canyon time -- in other words, at the top or the end of the previous exhibit -- deposition of sediment continued, with preferential deposition occurring in the structurally low areas off the flanks of the old Lower Cherry Canyon structure, resulting in relatively thick sediment accumulations in the structurally low areas off the flanks and thin sediment accumulations along the crest.

As a result, by Middle to Upper Cherry Canyon time significant -- the sediment subsurface had flattened significantly, such that stratal geometries that occur from this point on up into the Upper Cherry Canyon reservoir are completely different from those seen in the Lower Cherry Canyon and Upper Brushy Canyon below.

Now, this exhibit also dramatizes some of the internal changes that occur within the Upper Cherry Canyon reservoir, especially along dip, and this a dip-oriented schematic from northwest to southeast.

As you can see from this exhibit, the interval changes character significantly from more dominantly porous sands in the southeast and central portions of the field to tight carbonates as you go to the northwest. This updip pinchout of porous basinally restricted sands into tight carbonates controls the lateral distribution of this reservoir.

Q. Now, you've shaded portions of this exhibit. What do those colors indicate?

A. The yellow highlighting indicates the presence of porous sandstones, as opposed to low-porosity carbonates, shown in blue, that become more common as you go to the northwest in the Upper Cherry Canyon. The brown shading represents shales at the bottom of this exhibit.

Q. Okay. Could you discuss the continuity of the formation which is being unitized? And I'd refer you to your cross-section, Exhibit 16.

A. Okay. Yes, if you'll refer to Exhibit 16, this is, once again, a dip-oriented cross-section -- in other words, running from the northwest to the southeast. The location map on the right there, just above the title blocks, identifies the location of this cross-section.

On this cross-section I've colored in each of the two reservoirs, the major producing intervals that we discussed earlier, the lower interval being this Upper Brushy Canyon reservoir, the upper interval being the Upper Cherry Canyon reservoir.

As you can see, the two producing intervals are geologically continuous across the proposed unit area, especially in the Upper Brushy Canyon.

Please note that the Upper Brushy Canyon is not productive in the low structural positions off the flanks of the structure.

Now, Exhibit 16 also displays some of the variability that we discussed earlier in the Upper Cherry Canyon. Note that the upper part of this reservoir changes from dominantly porous sandstones in the southeast portion to low-porosity carbonates to the northwest.

At the northwest corner -- By the time that you get to the northwest corner of this cross-section, rock of significant reservoir quality is greatly reduced and occurs only in the lower part of the Upper Cherry Canyon.

Q. Okay, Mr. Cantrell, could you now move on and discuss the areal extent of the Avalon Pool? And I'd refer you to your Exhibits 17 and 18.

A. Yes, if you'll please refer to Exhibits 17 and 18, these are structure maps on the tops of the two reservoir intervals.

Exhibit 17 is a top of the structure of the Lower Cherry Canyon/Upper Brushy Canyon reservoir. This exhibit, Exhibit 17, displays the -- strongly, the anticlinal nature at the top of the reservoir in the Lower Cherry/Upper Brushy Canyon reservoir, with beds dipping away in all four directions from a structural crest.

I've also annotated on this map in red the limits of proven production, known, proven primary production, and shaded within that in green.

These limits appear to correspond fairly well to the structurally highest portions of this surface.

In contrast, if you'll look at Exhibit 18, which shows the top of the Upper Cherry Canyon Reservoir, there doesn't appear to be much in the way of structural closure along this reservoir.

I've also annotated on this map the limits of known proven primary production. As both these maps show, Exhibit 17 and Exhibit 18, the unit area includes all known proven primary production.

Q. How was the unit outline determined?

A. If you'll refer to Exhibit 19, the unit outline as it was originally proposed in 1991 and as it currently exists, was designed to include all tracts that have currently active Upper Cherry or Upper Brushy completions, and these are shown in the middle of the unit outlined there in the sort of dark green/bright green shading there.

In addition to this core of primary development, we've also included an outer ring of adjacent 40-acre tracts from this core of primary development. This outer ring was included for two main reasons: first off, to allow expansion for a later potential $CO_2$ project, as well as to utilize existing wellbores that may occur in this outer lane, existing Delaware wellbores.

This proposed unit outline, which is labeled on this map, corresponds to the areas of highest mapped net thickness, hydrocarbon pore volume and moveable oil and has been approved by both the State Land Office and the Bureau of Land Management.

Q. Kind of skipping to a separate subject, Mr.

Cantrell, are there any faults or hydrologic connections between freshwater sources in this area and the injection formation, injection intervals?

A. After reviewing the surface and subsurface geology for two miles within and around the proposed unit area, I found no evidence of faulting in the area which might provide a conduit between the injection intervals and any freshwater sources.

Q. Were Exhibits 10 through 19 prepared by you or under your direction?

A. Yes, they were.

Q. And in your opinion, are the granting of Exxon's Applications in the interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

MR. BRUCE: Mr. Examiner, at this time I'd move the admission of Exxon Exhibits 10 through 19.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Exhibits 10 through 19 will be admitted into evidence at this time.

Are you passing the witness at this time, Mr. Bruce?

MR. BRUCE: Yes, sir.

EXAMINER STOGNER: Mr. Carr, your witness.

MR. CARR: I have no questions of this witness.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin, your witness.

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER STOGNER: Do you need a little bit of time, sir?

MR. KELLAHIN: No, sir, I'm just looking for the reference in Exhibit 10.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Cantrell, let's focus on the upper reservoir of the Cherry Canyon. There's a portion of Volume I, Exhibit 10, and it's in the E section --

A. Okay.

EXAMINER STOGNER: Which section?

MR. KELLAHIN: It's in E.

EXAMINER STOGNER: E?

THE WITNESS: It says "Mapping and Volumetrics"?

MR. KELLAHIN: Yes, sir, it says "Mapping and Volumetrics", Section E.

The narrative that's contained in this geologic portion of the work, does that represent your work product?

A. The narrative part -- Yes, it does. Not all of the tables do, however.

Q. All right, sir. If you'll turn -- Some of the numbering is a little confusing until you work with the books a little bit, so bear with me.
A. Okay.
Q. If you'll turn in the narrative text, turn to where the bottom of the page is numbered E-4 and the next page is E-5. You've got a narrative presentation that deals with the Upper Cherry Canyon. Are you with me?
A. Uh-huh.
Q. Okay. Now, you can -- Independently of what you have testified to, you could read this and get your geologic conclusion about the Upper Cherry Canyon?
A. In general, yes.
Q. All right, sir. Are there any statements in this part of the narrative with which you now have disagreement?
A. I'd have to review this at this point. This report came out in 1992. I think in general the geologic model has not changed since then.
Q. All right. Since August of 1992, have you changed any of the material geologic components in either of these two parts to Exhibit 10?
A. I don't believe so.
Q. All right. When we work with the narrative, then we can go to the map book, which is Volume II, and let's follow how you have constructed the geometry and the

architecture of the upper reservoir, and let's start -- I'll simply take the sequence that you have chosen in the narrative.

In looking at the Upper Cherry Canyon, the first component of the analysis deals with maps 15 through 18. Here you're attempting to deal from a gross to a net --

A. Correct.

Q. -- get a net thickness based upon some porosity cutoff and other components to derive maps 15 through 18, all right?

A. That's correct.

Q. Okay. As we build the maps for the upper reservoir, turn to Map 18 and describe for me how this porosity thickness map fits in.

Now, I want to have you help me. The orientation as I see you present it is a difference between what you see in the southeastern part of the reservoir, moving into the northwest.

A. Right.

Q. That's the orientation?

A. That's correct.

Q. All right. When we start in the southeast part of the reservoir, then, in the Upper Cherry Canyon --

A. Right.

Q. -- using Map 18 --

A. Right.

Q. -- take me from that point up northwest and show me what happens to porosity thickness.

A. Okay. Well, basically it runs -- That cross-section runs from the southeast corner of Section 25 across Section 31, down into -- what is it? -- Section 32 there.

So, you know, the point I was making before about how net thickness, porosity thickness, if you wish to consider that parameter, is greater, you have more porous sand in this southeastern and central portion of the field than you do as you move updip, as you move toward that shelf margin we described earlier.

Q. In this reservoir, when you dealt with the net porosity thickness, I think it was a 10-percent cutoff?

A. That's right.

Q. All right, generalize for me what happens to that net porosity thickness. It moves from a general range of net in the southeast up to what level of net porosity thickness in the northwest?

A. Well, you can see for yourself on the map. I'll just read off for you some typical values.

You know, in the -- What? The southwestern portion of Section 31, I'm seeing values on the order of 30, in terms of feet of porosity thickness.

Moving across Section 31, on the order of -- I don't know, 25 to 20, on average, I guess.

And then by the time you move on over, across, onto the northeast there, the southeastern corner of Section 25, porosity thickness is getting down into the order of eight to ten feet.

Q. Okay. Stop for a moment and pick up the type log. I've lost track of the exhibit number, but it's --

A. Okay.

Q. -- it's the little type log that you have.

A. Right, that is Exhibit 13.

Q. I want to make sure the Examiner understands the nomenclature, is what I'm driving at here.

When we look at Map 18 and we're looking at a net porosity thickness, we have a top and a bottom to the interval being mapped?

A. That's correct.

Q. Using Exhibit 13, for purposes of Map 18, describe for us the interval that's being mapped.

A. It is from the -- Well, the top of the reservoir is sort of a combination of the base of the Goat Seep Reef and the top of the Upper Cherry Canyon reservoir.

At times, as we noted earlier, that red surface comes down and erodes the green one -- okay? -- in which case we use the red surface.

So it's from the top of the Upper Cherry Canyon reservoir to the base of the Upper Cherry Canyon reservoir, as it's labeled on this exhibit.

Q. That is the interval I'm looking at on Map 18?

A. That's correct.

Q. All right. When you're looking at that interval on a given log, for example, the FV3 -- and we have an example of it in the book, there's a cross-section --

A. Yeah.

Q. -- that shows that -- how are you determining the value by which you have determined the height of that porosity?

A. The height of the porosity? I'm not sure what you're saying.

Q. Well, you're counting values, you've got 10-percent porosity cutoff on the log.

A. Right, just --

Q. Within this gross interval, then, you are identifying a certain thickness?

A. That's correct.

Q. Okay?

A. Just as you described it, we apply a porosity cutoff, and all porosity greater than cutoff is counted on a foot-by-foot basis.

Q. All right. That net thickness becomes one of the values, then, in determining under your analysis what the distribution of the reservoir pore volume is eventually going to be?

A. That's correct.

Q. All right. The next component is, you have to deal with a water-saturation component?

A. Right.

Q. And in order to get the hydrocarbon pore volume distribution, you're going to take height times porosity, times one minus this water saturation component?

A. That's right. We'll -- Porosity thickness, the map we were just looking at, which is the product of net thickness times average porosity for that interval, gives you porosity thickness. Porosity thickness times one minus water saturation gives you hydrocarbon pore volume.

Q. All right, let's deal with the water saturation portion, then.

A. Okay.

Q. If you'll look in the narrative, the next paragraph that's been prepared refers you back to Map 19. So let's turn in the map book and go to the next map.

When you dealt with water saturations in the upper reservoir, lead us through a word description of what you are visualizing when you look at Map 19 and follow water saturation values.

A. Okay. Well, water saturation values are obviously decreasing as you go from the southeastern portion of the mapped area to the northwest.

Q. Give us a range. When we start in the southeast, the water saturation values are in this 70 percent?

A. Yeah, 65 to 70, something like that.

Q. And by the time we get up into the Premier tracts up in the east half, east half of 25, what does the map show you as to the value?

A. I'm seeing 40 to 50 percent.

Q. Is there a geologic explanation to the change of percentage value and water saturation?

A. To the change in --

Q. Yeah, going from 70 up to 40, 45.

A. Well, it's decreasing water saturation.

Q. Okay. The closure of the reservoir --

A. Right.

Q. -- describe for us what you see in terms of reservoir closure to give us a container in which to hold the hydrocarbons, starting again at the southeast.

A. Okay --

Q. What do you do?

A. Yeah, again, as I tried to describe in my testimony --

MR. BRUCE: Are we talking Upper Cherry?

Q. (By Mr. Kellahin) Only Upper Cherry.

A. Right. As I tried to describe in my testimony, there's several components to the trap for this reservoir. One of them is the structure. We presented a structure map, okay? And what you see in the structure is basically a structural nose, okay? So there's some small closure on that structure, but not a whole lot. At any rate, so there is a structural component to it.

But the main trapping mechanism is a lateral seal to the reservoir, and that is the loss of porosity, loss of porosity thickness as you've just described, from the southeast to the northwest, again owing to this increasing presence of tight carbonates as you go to the northwest.

Q. As you're attempting to geologically describe the container for the hydrocarbons, when we look at the southeastern corner, the values that control the hydrocarbons in that southeastern corner of the reservoir are what, sir?

A. I'm sorry, I don't understand your question.

Q. All right. What is the closure process by which the hydrocarbons are not moving farther southeast?

A. Okay, it's just a structural closure.

Q. All right. When you go to the north and northwest, as you've illustrated, I think, on the cartoon, Exhibit 15 --

A. Right.

Q. -- when you're moving up into the north and northwest, you have a different geologic component --

A. That's correct.

Q. -- by which to determine what that western/northern boundary is?

A. That's correct, a stratigraphic component, again, this updip pinchout of porous basinally restricted sands into tight carbonates.

Q. As you attempt to approximate the edge of the container on the north, you're looking at log information?

A. Up in -- Where?

Q. In the northwest, in the Premier tract.

A. Yeah, in the Premier tracts, correct.

Q. When you drew the line that shows the productive limits of the Upper Cherry Canyon, Exhibit 18, what caused you to draw the red line where it is within the interior of the boundary?

A. I'm sorry?

Q. Exhibit 18 was in the supplemental package.

A. Okay.

Q. The whole unit area is shaded with blue, and then superimposed upon that is the green area with a red border to it.

A. And what is your question?

Q. The question is, what is the relationship to the limits of the reservoir versus the proven primary production limits as inferred on this display?

A. Well, as I testified, the limits of proven primary production from this reservoir are completely enclosed within this unit outline.

Q. All right. What tells you geologically that there is not production beyond the red line on the display?

A. The red line represents nothing geologically. The red line simply represents proven primary production. In other words, where is there production from the Upper Cherry Canyon? There's nothing geologic about that line.

Q. And the Examiner should not take it to mean that that's the limit of production --

A. Possible -- It's the limits --

Q. -- of possible future production?

A. It's the limits of primary production.

Q. And that's all it is?

A. And that's all it is.

Q. When you're trying to determine the western boundary of the reservoir for the container and you're looking to decide where that porosity stops and you make that transition into nonproductive rock -- I guess it's a dolomite at that point --

A. For the most part, that's correct.

Q. What tells you as a geologist that you're into that transition?

A. I'm sorry, can you restate your question?

Q. Yes, sir. What values or data are you using as a geologist to set the western boundary?

A. The western boundary of the unit?

Q. Yes, sir.

A. The western boundaries of the unit are not really defined on the basis of geologic parameters, although they do support the definition that we've used.

As I testified, the unit outline was defined on the basis of first off looking at where are there active Upper Brushy and Upper Cherry completions, where is there current production?

And from that core of proven primary -- current primary development, we've extended out one tract, basically, one 40-acre ring all the way around, for the reasons that I testified to.

Q. All right. I don't want to misunderstand you. That unit boundary does not represent the limits of the reservoir?

A. What it -- Well, it does represent the areas of highest oil satura- -- of highest hydrocarbon pore volume, of highest net thickness, moveable oil and so forth.

So it does correspond to the best parts of this reservoir.

Q. When we look at Map 20, then, you've got the Upper Cherry Canyon, you've got your hydrocarbon porosity thickness map. There are going to be areas of the reservoir to the west that are still reservoir in the Upper Cherry Canyon that are outside the current boundary of the unit, are there not?

A. There is indeed mapped hydrocarbon pore volume west of that unit boundary, as we've drawn.

Q. Is the method one where you would construct a cross-section using values from east to west, from northwest to southeast, and then on that cross-section you're going to make a judgment as a geologist as to where between those two control points this reservoir thins to the point that you can draw a zero line on your contour map?

A. Again, the zero line, the line that's on here, is not geologically defined. It was more than geology that went into defining the reservoir or the proposed unit area. Beyond a certain point, you're only relying upon mapped oil in place, and you're really getting far away from proven primary production.

Q. Remove the dark line from Exhibit 20 visually. There are values beyond that line that show hydrocarbon porosity thickness?

A. That's correct.

Q. The methodology employed by you and others is to simply construct values, either in the way of a cross-section or otherwise, to estimate between control points what happens to the reservoir?

A. That's correct.

The point I would refer you to, though, again, coming back to primary production, if you look at the wells that produce from this reservoir on the east side -- I mean, you mentioned the FV3 earlier. It has cum'd 5000 barrels of oil.

There's another well immediately to the south of it in the Citadel ZG State Number 1 that has cum'd a little over 3500 barrels of oil and has an estimated ultimate recovery of about 6000.

So there's more than geology in the unit outline, is the point.

Q. Having constructed your description of the reservoir and reduced it to a map, show me in the book where I go to find the net thickness value attributed to the FV3 that has been put on the map. There's a table somewhere in this --

A. Well, it -- Yeah, it's actually probably annotated on the map. We can just look at that. I'm not at this point aware of the table. There may be one in there.

The point is, you can read off the map what the value would be at that point.

Q. And that's where I want to ask you the question. When you're working with the logs, how are you mechanically -- your methodology for handling that correlation and picking those values. Has someone taken these logs and digitized them for usefulness in terms of computer review, and then you've drawn your map from there? Or did you simply go in and look at each log on a hands-on basis and try to pick that porosity thickness?

A. I have to ask you a question about your question, first off. Are you talking about the volumetric work, or are you talking about correlations or --

Q. I'm talking about the volumetric work.

A. Okay. Yes, the logs -- You know, as we mentioned in Exhibit 11, I believe, the stratigraphy summary --

Q. Twelve.

A. Twelve, thank you. There are 71 wells out there that we had digital data for in the field area.

Q. All right. Who digitized the logs that were then used for the rest of the review?

A. A vendor in Houston, QC Data.

Q. Okay, you could do that manually, I guess? There's another way to go about it, right?

A. Exactly.

that?

A. Right.

Q. And when I'm looking at net average water saturation, I'm looking at a log-derived value, am I not?

A. That's correct.

Q. That's not been adjusted or otherwise manipulated? This is your log-derived value?

A. That's right.

Q. How do you -- how is it -- Maybe it's the engineer that answers the question. How do you take that distribution of porosity, the hydrocarbon pore volume distribution, and reduce it to the value that we talked about with Mr. Thomas in the spreadsheet that's contained in the unit agreement?

A. I'm sorry, I'm not familiar with the spreadsheet you're talking about. Is it a reserves statement? Is that --

Q. In effect, I think that's where you end up.

A. Again, that is -- I'm not qualified to --

Q. That's an engineering function that occurred after your work?

A. Right.

Q. If you'll turn to the map book and if you'll go past the maps and let's look at a cross-section there, it's captioned at the top, "Avalon (Delaware) Field Structural

Q. All right. Now, we know the thickness value, we've got the water saturation, you have drawn your map of the reservoir.

Show me where you have constructed the map that gives me the hydrocarbon pore volume distribution for the Upper Cherry Canyon reservoir.

A. It's the map you were just referring to, I believe. For the Upper Cherry Canyon it would be Map 20.

Q. All right. Completing the narrative for the E section, if you move behind that there's a series of exhibits, and what I want you to look at is Exhibit E-5, which is -- I'm sorry, it's E-4. E-4 is the summary.

A. Uh-huh.

Q. Are you with me?

A. Uh-huh.

Q. On the summary of volumetrics, then, what has occurred is, Map 20, someone has gone through and planimetered or figured out the size of the container to give you an Upper Cherry Canyon original oil in place value of 107 million, all right? Is that correct? Is that how that's done?

A. Yes, that's correct. It's all done in the computer, but essentially it's the same process.

Q. All right. And the values by which oil in place, then, is calculated are listed on this spreadsheet above

Cross-Section 2".

A. I'm sorry, I don't have a copy of Volume II. Could I borrow --

Q. You don't have -- It's the map book, Volume II.

A. The big one there?

Q. Yes, sir. It's the cross-section 2.

EXAMINER STOGNER: What's the headline again?

Q. (By Mr. Kellahin) It says "Avalon (Delaware) Field Structural Cross-Section 2".

On the far left of the cross-section it says "Northwest". The first well is the FV1, the second well is the FV3. The next well is the C5.

A. All right.

Q. Using the shorthand code, I think just for convenience's sake, we've reduced some of these descriptions to a few letters. Let's take the type log which was shown on Exhibit -- Was it 18? The exhibit that's got the values on --

A. Here it is.

Q. All right, Exhibit 13. Exhibit 13 has got the nomenclature --

A. Okay.

Q. -- on the type log. And for reference, if I'll set that beside this cross-section, when we're looking at the Upper Cherry Canyon reservoir, on the log for the FV3 show me where we have the top and the bottom of the reservoir in that log.

A. Okay, the top of the reservoir in the FV3 would be the heavy bold black line there, labeled "UCH Downlap". The base would be the lower heavy bold line labeled "UCH Base".

Q. In this instance, the downlap is not in close proximity to the base of the Goat Seep?

A. Correct.

Q. And you've used the downlap, then, as the upper part of the reservoir?

A. That's right, exactly.

Q. What caused you to pick -- or perhaps you didn't. Do you have a geologic explanation as to why Exxon has the top of the reservoir in this log at this point?

A. Yes, I mean, there was a surface, and in this exhibit it's labeled the UCH downlap. There was a surface that we were mapping across the field.

And on a fieldwide basis, as I said, the surfaces were -- that one in particular is capped by shales, anti-carbonates. It's sort of a couplet there. This appeared to describe the top of the reservoir.

Above this point, even though there may indeed be porous sands present in a few wells, there were no mud log shows, there was no perforation, no production above that point.

Q. When we look at the FV log itself, what caused you to put the downlap at that point, just above the 2600?

A. At this point we were going on the presence of a limestone shale, limestone couplet -- or carbonate dolomite, as you were saying.

Q. Are you reading the gamma-ray track on the left side?

A. Yeah, that is the interpretation we made; when it's low gamma ray, we're generally interpreting that it's probably a carbonate.

Q. And because you're looking for this presence of dolomite in the absence of reservoir porosity in the western boundary, that's the kind of thing you look for?

A. Well, that is one of the things that we look for. Again, let me reiterate something I said in my direct testimony. The correlations here are not necessarily based on a single surface or a single kick or a single point on the well log. We're looking at overall stacking patterns that occur in the reservoir.

Q. Well, I understand the point is that once you make this pick you want to see if it fits in to be logical with offset well control and to have some regional sense to it?

A. That's right, with offset well control, as well as what's going on underneath the surface in this well. Now, there's -- What is the rest of the section doing? What is the picture that emerges from looking at that as well? And how does that total package, then -- you know, not only the individual little pick that we made here, but the package of events that occurred below that, how does that correlate with the offset wells?

Q. All right. When you look at the middle marker here, Upper Cherry middle marker that's on the log here --

A. Uh-huh.

Q. -- what value on the log did you use to tell you that's where it ought to be located?

A. In general, it was a high gamma-ray signature, again at the top of a -- you know, a significant series of markers.

Q. And then again, the base, how was that determined on this log?

A. Well, the same procedure. The methodology was consistent throughout.

Q. Did you do the actual work on the FV3 well?

A. Well, I along with another Exxon geoscientist.

MR. KELLAHIN: Thank you, Mr. Examiner, that concludes my questions.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Bruce, any redirect?

MR. BRUCE: Mr. Examiner, I have just one point of clarification.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Cantrell, I think if you'd look at your Exhibit 18 -- Do you have that?

A. Yes, uh-huh.

Q. And you've got that red line, the limit of proven primary production in the Upper Cherry Canyon, and you referred to a couple of wells, the FV3 and the ZG1. Let's identify those for the Examiner.

Now, let's -- The Premier tract is the tract in the northwest corner of the unit; is that correct? The sections aren't numbered, but it's the east half, east half of Section 25?

A. That's correct.

Q. And the Premier well you were talking about, the FV3 --

A. Right.

Q. -- is in the southeast quarter, southeast quarter of that section?

A. That's right, it's in the extreme southeastern corner of that section.

Q. And then immediately below that is the Yates ZG1 well; is that correct --

A. That's correct.

Q. -- in the northeast quarter, northeast quarter of Section 36?

A. That's correct.

Q. And once again, what are the primary production figures on those two wells?

A. The FV3 well, the Premier well, has a total cumulative production of 5100 barrels of oil.

The ZG1 at this point -- well, the last production data I have is as of April, had a total cumulative production of a little over 3600 barrels of oil, on its way to what we estimate an ultimate recovery for that well to be, about 6000 barrels.

Q. And those wells have no Upper Brushy Canyon production?

A. That's correct.

Q. It's solely Upper Cherry Canyon production?

A. That's correct.

Q. So they appear to be correlative wells?

A. Right, analogous, geologically analogous.

Q. Okay. And there's no proven production to the west of that from this zone?

A. From this zone, that's correct.

MR. BRUCE: Nothing further, Mr. Examiner.

EXAMINER STOGNER: Thank you, Mr. Bruce.

I don't believe I have any further questions of Mr. Cantrell at this time. He may be excused, unless there's anything further.

MR. BRUCE: Nothing of Mr. Cantrell at this time. There is a chance I may recall him as a rebuttal witness.

EXAMINER STOGNER: Okay, at this time let's take a 10-, 15-minute recess.

(Thereupon, a recess was taken at 1:57 p.m.)

(The following proceedings had at 2:18 p.m.)

EXAMINER STOGNER: Hearing will come to order.

Mr. Bruce?

GILBERT G. BEUHLER,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name and city of residence?

A. Gilbert Beuhler, from Houston, Texas.

Q. What is your occupation and by whom are you employed?

A. I'm a reservoir engineer with Exxon Corporation.

Q. Would you please describe your educational and employment background?

A. Yeah, I have a bachelor's of science in petroleum engineering from the University of Kansas. I've been employed by Exxon for 12 years. I have several years' experience in operations of many Permian Basin fields, and I've had responsibility in areas such as drilling, workovers, forecasting field production, economics and such. I've also had several years' experience in property acquisition with responsibility for evaluating field performance and future value.

Q. Have you previously testified before the Division as a reservoir engineer?

A. Yes, I have, and I've also testified a number of times before the Texas Railroad Commission in Permian Basin cases.

Q. Would you please describe your involvement in the proposed Avalon-Delaware unit?

A. I've worked Avalon since October of 1989. I assisted in the preparation of the technical report which was used as the basis for unit equity.

My responsibilities have included analyzing field performance using data such as historical production, fluid data, special core analysis and bottomhole pressures.

I was part of the engineering team responsible for analyzing the field performance and determining the optimum future field development of Avalon. This included reservoir simulation and history matching of past well and field performance.

I was also the engineer responsible for the approval and analysis of the Yates C Federal Number 36, which was a well drilled in the Avalon field in 1990, which gathered extensive data used in the development of the technical report.

And I'm currently responsible for field performance predictions and economic analysis.

MR. BRUCE: Mr. Examiner, I tender Mr. Beuhler as an expert engineer.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Mr. Beuhler is so qualified.

Q. (By Mr. Bruce) Mr. Beuhler, referring to Exhibits 20 and 21, will you please describe the history of the Avalon-Delaware Pool?

A. Okay. Exhibit 20 is a plat of the unit. It indicates development of the pool.

The first completion and commercial production within the proposed unit area occurred in December of 1983. There have been 37 completions within the unitized -- proposed unitized formation, all on 40-acre spacing.

The current status within the unit area, proposed unit area, is 25 active producers and three active water disposal wells.

And let me note some of the things on this plot to kind of get you oriented.

The proposed unit area is the solid line around it, and we have noted the various operators. There's currently four operators. They're lined out, and the various acreage operated is shown in different colors with Exxon being in yellow, Yates being in green, Premier being in kind of that light stippled blue, and MWJ in that light stippled red.

Also note that green 80-acre Yates-operated tract over on the west side of the field.

The wells that have completed in the Delaware within the proposed unit area are shown as black dots. These would be wells that would be owned by the unit. Current injectors are shown with black dots with the arrow through them, and then other associated wells are shown as open dots.

Turn to Exhibit 21, the next exhibit. It's a plot of historical production of oil, gas and water for all unit wells, and let me describe it for you.

It's a plot of log rate versus time. Oil production in barrels of oil per day is shown as a solid green line. Gas production in MCF per day is shown as a solid red line. And then water production is the blue line.

The -- It's on a semi-log scale from 100 to 10,000 on rate.

Oil production reached a maximum in July of 1984 at 1760 barrels a day -- that's that peak you see in 1984 -- after which production began a primary decline.

Due to workovers and special pool rules, production decline was mitigated for a while in the early 1990s. That's that rise you see in oil production there. Thereafter, production has declined at approximately a 20-percent rate.

The large production drop that occurred in 1994 is due to the shut-in of two wells in order to make up some overproduction.

Cumulative production through January of 1995 was 3.4 million barrels.

Q. Would you describe the distribution of production from the pool? And I refer you to your Exhibit 22.

A. Yeah, Exhibit 22 is a map of the primary production distribution. It's -- Well, it's just like Exhibit 20 as far as showing the proposed unit area and the operators colored in.

But now each well location is shown as a pie diagram, and the size of the pie is the well's primary estimated ultimate recovery. The various slices are shown on the legend. The cumulative production to 1-1-93 is shown as the red part of the pie. The production that has occurred between 1-1-93 and 1-1-95 is shown as yellow. And the remaining primary reserves from decline-curve analysis is shown as the green part.

Note the area of significant primary production. It's about a 1000 acres there in the central part of the proposed unit.

About three-quarters of the production has occurred on Exxon-operated leases, and over 99 percent of the total production has occurred on Exxon and Yates-operated leases.

Q. What is the drive mechanism in the pool?

A. The drive mechanism is a solution gas drive. Current GOR is about 3000. Reservoir pressure has declined from initial pressure of 1195 p.s.i. in the Upper Cherry and 1579 in the Upper Brushy, to an estimated pressure of about 1000 p.s.i. in both zones.

Q. Is the unit area in an advanced state of depletion with respect to primary production?

A. Yes. Turn to Exhibit 23. This is a plot of historical production rate, oil rate per active producer and GOR.

Once again, it's on time, 1983 to 1995, semi-log plot. The green curve is as before, it's barrels per day from proposed unit wells, now showing gas-oil ratio as the red line in standard cubic feet per barrel.

And if you take the oil in barrels per day and divide by the active producer, you get the purple line, which is barrels per day per producer.

Production overall has declined from over 1700 barrels a day down to the current approximately 400 barrels a day, and oil rate per active producer has declined from a peak of about 60 barrels a day down to the current 18 barrels a day, while the GOR has increased from 600 to about 3000.

Note that the solution GOR is approximately 400, which means that the reservoir is below bubble point and producing free gas, which can cause oil viscosity to increase and future waterflood recovery to potentially decrease due to the increasing mobility ratio.

Turning to Exhibit 24, this is a plot of oil rate versus cumulative oil. The green curve is barrels of oil per day, as shown on the Y axis. But now instead of plotting versus time, I'm plotting versus cumulative oil production in thousands of barrels.

So just pick a number. That 3000 in the middle would represent 3 million barrels from the unit.

Note that the solid line, vertical line splits historical and future projection. That future projection was based on reservoir modeling and decline curve analysis.

Cumulative production, as noted before, through January of 1995, was 3.4 million barrels. You can see where it slices the X axis there.

And the field is at an advanced stage of primary depletion with the remaining reserves of continued operations of 800,000 barrels, and that's noted underneath that projection, which is the dot-dashed green line.

With a total EUR of 4.2 million barrels, the field is over 80-percent depleted.

Q. Has the portion of the pool which you propose to unitize been adequately defined by development?

A. Yes, it has.

Q. And is the portion of the pool being unitized suitable for unitization and waterflooding?

A. Yes.

Q. Referring to your Exhibit 25, what injection pattern do you propose to use for the waterflood?

A. Okay, Exhibit 25 is a plat showing the planned development for implementation of a waterflood in the Avalon field.

Location of the initial water injections are shown, and as on the legend they're shown in the open circles with arrows through them.

Just to briefly describe the rest of the plot, the proposed unit area is now shown in the light blue, and then the current wells are shown in dark green, solid green, with other wells that would not be used during the waterflood but be available for future use as open circles.

As I noted, the wells that would be used for injection are shown by the blue open circles, with one proposed conversion as a solid blue circle with the arrow through it, and the pattern lines are drawn in.

The proposed pattern would be a 40-acre inverted fivespot, and there would be 19 injectors, 27 producers, one saltwater disposal well and three water-supply wells.

Under "Scope" notice that -- Of course, we would also be installing water-treating and -injection facilities, and we estimate we could start two months after the unit is approved.

Q. How did you project reserves to be recovered by the waterflood and by the potential $CO_2$ flood? And I would refer you to your Exhibit 26.

A. Okay, Exhibit 26 summarizes the methodology that we use to predict future field performance at Avalon.

The geologic model results are combined with fluid properties and development plan and are used with a numerical simulator to predict future flow streams and reserves.

On the first bullet there, "From the Geologic Model", we use it to build the layering model and volumetrics used in the simulation.

Second bullet down, the numerical simulator we used is a three-phase two-dimension simulator that used 312 gridblocks for ten acres.

Several calibrations were performed, and we calibrated with actual field performance available, such as cumulative oil, gas, water, oil rate, water cut, GOR, things like that.

Future primary prediction, continued operations, was checked by well and field decline curve analysis. That also predicted the 4.2 million barrels of EUR I noted before.

The model agreed quite closely with historical production and decline-curve analysis. We used this model, note on the last dot, to predict continued operations, waterflood and $CO_2$ recoveries.

Q. Does the close match you mentioned help verify Exxon's geologic model?

A. Yes, it does.

Q. Let's move on to your Exhibit 27, and would you discuss the predicted unit performance under waterflood conditions?

A. Okay, Exhibit 27 is a plot of the projected production for the unit under continued operations and waterflooding. Now, I'm showing production rate versus time for the next, in effect, 25 years, from 1980 through the year 2020.

Production in barrels of oil per day is plotted on the Y axis there. The current date is designated with a solid line, vertical line, historical and future there. The cum production is shown as the solid green line, the 3.4 million barrels I noted before. The continued operations estimate of .8 million barrels is shown by the dash-dot, long-dot-short-dot, green line. And then the waterflood prediction is shown as the solid blue line.

The waterflood reserves would extend the life by over 50 years and yield reserves of 8.2 million barrels, which is over 10 times the reserves that would be recovered without the project.

Q. You mean the remaining reserves in the --

A. Remaining, yeah, sorry, remaining -- continued operation.

Q. What is Exhibit 28?

A. Okay, given the amount of oil i place and the high initial water saturation we've seen at Avalon, we do feel there is potential for a miscible $CO_2$ flood in the future, and Exhibit 28 does show a potential development plan for implementation of a $CO_2$-injection project.

As noted, the map is pretty much the same as before with the waterflood proposal, except for now we've added the black triangles, which would be proposed $CO_2$ phase injectors.

The pattern would not change from the waterflood We'd still use a 40-acre inverted fivespot. The development would add 18 new patterns, effectively doubling the size of the developed area, and would encompass 37 patterns with 37 $CO_2$ injectors, 55 producers, one saltwater disposal well and one water-supply well.

The earliest we could start would be 1999, and the issue there is, we need to wait until we have attained miscibility pressure for $CO_2$ and reduced gas saturation. That takes at least three years.

Also, we need to run injectivity tests. That's a key parameter for the running of a $CO_2$ project.

And of course it would be contingent upon prediction of oil prices at the time.

Q. What is Exhibit 29?

A. Okay, Exhibit 29 is a plot of the field performance, with a $CO_2$ flood implemented as shown on the previous development map.

The flow streams shown are determined using the same methodology that were discussed before, both primary and waterflooding.

The map -- The plot is pretty much the same as before, except for now we've added the solid red line, which would be a future $CO_2$ reserve flow stream prediction. And the project life is very long; it would be over 60 years. But the reserve target is large, 39.9 million barrels, versus the 9 million that are estimated for remaining primary and waterflooding.

Q. Now, you've already touched on this a little bit, Mr. Beuhler, but I'd like you to reiterate.

What about the carbon dioxide flood potential? Why aren't the working interest owners making a commitment today, in 1995, to go forward with that aspect of the project?

A. Yeah, I did touch upon this a little bit before. But here's -- They key thing is, we need to analyze what we do early on in the waterflood. We need to analyze the drill well data, the waterflood -- early waterflood performance data. Like I said, do a $CO_2$ injectivity test; that's a key economic parameter, certainly. And make sure we have achieved $CO_2$ miscibility pressure and reduced the gas saturation. Like I said, it would take at least three years from when water injection begins to do that.

At that time the working interest owners must then review many factors, of course, including predicted oil prices, in order to determine whether to proceed with the $CO_2$ flood. The capital investment for a $CO_2$ flood project could exceed $70 million, and therefore the decision on whether or not to proceed must be made very carefully.

Q. With respect to the waterflood alone, what additional facilities will Exxon need to install for the unit?

A. It will need to install facilities necessary for the treatment of produced water, of supply and make-up water and the injection of both.

Q. Referring to your Exhibit 30, would you discuss the economics of the waterflood project?

A. Okay, in Exhibit 30 I have a summary of estimated incremental waterflood project economics. Note the assumptions I'm using.

I'm assuming the entire unit, 100 percent of the working interest, with an average 80-percent net-to-gross there.

Product pricing assumptions are shown. I'm using oil at $17.10 a barrel, escalated at 5.4 percent a year, and gas at $1.50 a thousand, escalated at 6.1 percent a year.

The capital investments for the project would be $14,400,000. As noted before, the incremental reserves received from that investment are 8.2 million barrels.

At the initial price shown of $17.10, these incremental reserves will generate approximately $140 million of revenue to the pool.

The present worth of the future profit, discounted at 10 percent, is $21,500,000 worth of payout in five years and a discounted rate of return of 30 percent.

Q. Will the oil and gas recovered by unit operations exceed the unit costs plus a reasonable profit?

A. Yes.

Q. And what is the estimated life of the waterflood?

A. About 50 years.

Q. Is the project area so depleted that it's prudent to apply an enhanced recovery program at this time?

A. Yes, it is.

Q. And is the waterflood Application economically and technically feasible, in your opinion?

A. Yes.

Q. Will waterflood operations in this portion of the pool prevent waste?

A. Yes.

Q. Will the operations result, with reasonable probability, in the increased recovery of more hydrocarbons, substantially more hydrocarbons, from the pool than would otherwise be recovered?

A. Yes.

Q. Will the unitization and secondary recovery benefit the working interest owners and the royalty owners --

A. Yes.

Q. -- within the pool included in the unit area?

A. Yes.

Q. Now, as a portion of this Application, Mr. Beuhler, you've requested some unorthodox well locations. What is Exhibit 31?

A. Exhibit 31 is a listing of the wells for which we seek unorthodox locations. These wells would be drilled as producers but will probably produce for less than 12 months if they are produced. They will then be converted to water injection for the waterflood.

Q. Let's move on to the injection portion of your Application. What is Exhibit 32?

A. Okay, 32 is the NMOCD form C-108, and its attachments, which was submitted with our Application.

Q. Okay. Would you please discuss the proposed water injectors?

A. Yeah, as I noted before, one proposed injector is currently producing and will require conversion to water injection. Its well data sheet is shown on page number 4. The page numbers are in the upper right, probably in pen, upper right there. And its wellbore sketch is on page number 5. That's the one conversion.

As to the new injectors that would be drilled, a well data sheet for a typical well is shown on page 6, and a generic schematic of the wells is given on page 7.

On each injector, we plan to install a seal-bore assembly, which basically serves the same function as a packer, within 300 feet of the top perforation and have a fluid circulated into the casing tubing annulus.

New wells will be acidized and frac'd during completion, and all wellheads will have pressure gauges installed on the casing tubing annulus.

Q. Now, keeping Exhibit 32 in front of you, Mr. Beuhler, and also Exhibit 33, would you briefly discuss the wells in the area of review?

A. Yeah, if you look at pages 12 through 15 -- I guess I can find that -- of the C-108, it contains a spreadsheet list of all mechanical information for the wells in the area of review, which penetrate the unitized formation.

Exhibit 33, the next exhibit, contains the calculation on top of cement. The top of cement was calculated by evaluation of temperature logs, cement bond logs or calculated from sacks of cement, but most strings did have cement circulated.

Q. Are there any plugged-and-abandoned wells in the area of review?

A. No.

Q. And are all freshwater zones isolated from injected fluids in the area of review?

A. Yes.

Q. Are there any freshwater wells in this area?

A. Yes, there are.

Q. Would you refer to your Exhibit 34, discuss its contents, and would you comment for the Examiner whether tests have been taken from those wells?

A. Yes, we have taken samples on two wells.

Exhibit 34, note it's the same proposed unit area, with all the wells shown.

A list of freshwater wells was obtained from the records of the State Engineer, verbally from our field employees and from area land owners.

Four freshwater wells may be active in the area of interest. All of these wells produce from the Rustler formation, the shallow freshwater zone.

Two of these wells were sampled, and these wells are shown on Exhibit 34. The two sampled wells are shown as the dark blue diamond.

Again, none of our injection water should reach these freshwater sources.

Q. And you mentioned samples. Are those water samples Exhibit 35?

A. Yeah, those two samples are contained on Exhibit

35.

Q. Now, Exhibit 35 is a two-page sheet; mine wasn't stapled.

A. Yeah, it's not stapled. It's two pages, one for each well.

Q. What will the initial injection pressure be?

A. Okay, initially we will comply with the .2-p.s.i.-per-foot surface injection pressure required by the Division.

Subsequently, we may seek approval of injection pressures higher than this, validated with step rate tests.

Q. Okay, and what is the source of water for the waterflood?

A. We'll use produced Delaware water.

Q. Is the unitized management, operation and further development of this pool necessary in order to effectively carry on your proposed secondary recovery operations?

A. Yes.

Q. And will these operations substantially increase the ultimate recovery of oil from this pool?

A. Yes.

Q. Now, let's move on to the participation of interest owners in the unit.

You have reviewed the participation formula in the unit agreement, Mr. Beuhler?

A. Yes.

Q. And in your opinion, does the unit agreement provide for a fair and equitable plan of unitization?

A. Yes, it does.

Q. Would you review your Exhibit 36 and describe how production will be allocated among the various tracts under the unit agreement?

A. Okay, Exhibit 36 is from Section 13 on page 7 of the unit agreement, which sets out the participation formula to be used for allocating production. This formula is based on primary, secondary and tertiary reserves.

And as shown on the bottom, the reserve --

Q. Mr. Beuhler, I think -- Let's look at Exhibits 36 and 37 together.

A. Okay.

Q. Thirty-seven is actually the participation formula; is that correct?

A. Yes, it is, that's the actual formula.

Q. Okay, go ahead with Exhibits 36 and 37 together, then.

A. Right. Thirty-six denotes by tract the reserves that are used in the formula that's shown on 37. The reserve figures used are shown there on the bottom.

For remaining primary, it's 1,192,200 barrels of oil, as of 1-1-93, as set out by the technical report.

The secondary reserves are 8,269,400 barrels.

And the tertiary reserves are 39,883,000 barrels, and they're split by various tracts.

These reserves were developed using the methodology discussed in Exhibit 26 and are consistent with the future production flow streams shown.

Q. And again, these reserve figures on Exhibit 36 come from the technical report?

A. Yes, they do.

Q. Okay. Did the working interest owners agree to use these numbers?

A. Yes, we took a ballot in April of 1994, and over 90 percent of the working interest owners agreed to use the technical report as the basis for unitization --

Q. Okay.

A. -- with only one percent disagreeing.

Q. Let's move on, then, to your Exhibit 37, which is the actual participation formula. Would you discuss the basis of the participation formula?

A. Yeah, what Exhibit 37 does is, it shows the rationale for the participation formula proposed in the unit agreement.

The basic framework for this formula was offered by Yates Petroleum. Exxon, with over 80 percent of the production, had taken the lead in proposing an equity formula. There were some injections to the formula proposed by Exxon, mostly pertaining to it being a two-phase formula. And in order to ensure working interest owner participation Yates offered to propose a single-phase alternative, and this equity formula shown on Exhibit 37 is the result of that Yates proposal.

Q. What is the underlying basis for this formula?

A. The intent was to base the formula on recoverable oil and include risk, basically risk with economic factors.

If we go through each piece, primary oil has the lowest risk, it's already developed, has established decline, has the highest value per barrel since it has low operating costs and no development costs. While there's a fair amount of remaining primary reserves, they constitute a small part of the total unit potential reserves, roughly two percent. It was given a 25-percent weighting factor, based on these factors.

Skipping down to tertiary, tertiary reserves are by far the largest part of the potential recovery, roughly 80 percent of future unit production, but they also have the highest risk. It involves large expansions of the unit area or developed area, and they are very sensitive to future production -- future pricing -- with the long project life.

They also have the lowest value per barrel, given that they have high development and operating costs. Thus, they were given a 25-percent weighting factor, equal to the primary reserves.

Secondary reserves are between primary and tertiary, both in amount and value. But the main objective of the unit is the implementation of the waterflood. Secondary reserves also have a relatively low risk with the project area encompassing the primary developed area. Thus, they were given the highest weighting factor, 50 percent.

And all these factors are shown on Exhibit 37.

Q. Did any other factors enter into this formula?

A. Yeah, and since initially only about half the unit is being developed, the working interest owners thought it fair to assign a participation factor to tracts on the fringe of the unit, tracts with only $CO_2$ potential, in return for their acreage being included in the future field development.

Q. Again, in your opinion is this formula fair?

A. Yes, I think it is.

Q. Could you give us an example?

A. Well, for instance, Exxon currently has 80 percent of the current production, but its participation under this formula would be reduced to 74 percent.

Q. You've sat in meetings where Premier's representatives were present, have you not?

A. Yes.

Q. And you've been made aware of at least some of Premier's objections to the equity formula?

A. Yes.

Q. In your opinion, is the participation formula and is the tract participation factors set forth in these documents fair to Premier?

A. Yes.

Q. Why do you so believe? And if you would, refer to your Exhibit 38.

A. Okay. Looking at 38 to help show this, Premier has had a total cumulative production from their tracts of 5100 barrels of oil, but they have no current primary production and no primary or secondary reserves.

But nonetheless, Premier would get one percent of production of the unit from day one. In fact, due to investment equalization set out in the unit agreements, Premier will probably have a positive cash flow from the beginning of the project.

Premier's one-percent equity, as shown, would give them 8000 barrels of oil for the unit's remaining primary production, and with the waterflood project would give them a total of 90,000 barrels. If the $CO_2$ flood is implemented, Premier would receive a grand total of 489,000 barrels.

Q. So Premier gets some of the value up front?

A. Right.

Q. What about -- You've heard Mr. Kellahin request that Premier be left out of the unit. What about that suggestion?

A. Well, first, as we noted, this field is a good candidate for a $CO_2$ flood. But to unitize without anticipating a $CO_2$ flood would be shortsighted, because by eliminating Premier's tracts, the potential $CO_2$ flood would have to be scaled back somewhat, causing a loss of reserves, income and royalties.

Second, if the tract is omitted now, it may never be brought in. And from a practical aspect, it will cause amendments to the unit documents and new state and federal approvals and re-ratification by interest owners.

Q. Have any interest owners on these fringe tracts, as we refer to them, other than Premier, approved unitization?

A. Yes, MWJ operates Tract 8 -- I think it's easiest to see if you go back to my Exhibit 20 -- which, like Premier's tract, is a fringe tract with low cumulative oil and features $CO_2$ reserves only. And they have approved the unit.

Also, the Commissioner of Public lands, which is the lessor of Premier's Tract 6 and other tracts, has approved the unit.

Q. Does the participation formula contained in the unit agreement allocate the produced and saved hydrocarbons to the separate unit tracts on a fair, reasonable and equitable basis?

A. Yes.

Q. One final exhibit, Mr. Beuhler, Exhibit 39. Could you identify that and describe what Exxon requests for the initial project area for the waterflood?

A. Yeah, if you look at Exhibit 39, the initial project area, pursuant to Division Rule 701 G, Part 3, will encompass 1200 acres, all located inside the unit boundary, and this area is described on Exhibit 39.

Q. And what project allowable does Exxon request?

A. We request that each producing well be granted an allowable equal to its capacity to produce.

Q. In your opinion, will the granting of these Applications be in the interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. And were Exhibits 20 through 39 prepared by you, under your direction, or compiled from company --

A. Yes.

Q. -- records?

A. Yes.

MR. BRUCE: At this time Mr. Examiner, I'd move the admission of Exhibits 20 through 39, and we pass the witness.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Exhibits 20 through 39 will be admitted into evidence at this time.

Thank you, Mr. Bruce.

Mr. Carr, your witness.

MR. CARR: I have no questions of this witness.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Beuhler, if you'll pull out Exhibit 25, which is a pattern for the waterflood, --

A. Yeah. Okay, I'm there.

Q. -- then you have a spreadsheet that shows the reserves by tract, broken out. It was attached to the unit agreement. Thirty-six and 25.

A. Okay.

Q. Thirty-six appears to be a reproduction of

Exhibit "D" to the Exhibit 2, which was the operating agreement?

A. Yes.

Q. When we look at the waterflood aspects of the project by itself, the eastern stack of 40-acre tracts, which include the Premier tracts, under your analysis they have no relative value for the waterflood purposes; isn't that true?

A. Correct.

Q. Under your analysis they have no contribution of remaining primary recoverable reserves; is that not true?

A. Correct.

Q. When you look at the waterflood map, there are no producer wells to be in the western tier of 40-acre tracts that were discussed; is that not true?

A. Correct.

Q. And you can complete your injection pattern for the waterflood project without utilizing any of those tracts?

A. Correct.

Q. The calculation of remaining primary reserves for the Premier tract was done by you?

A. It was done with my assistance. It was done by several people.

Q. All right, sir. Do you understand the process that was utilized by Exxon to determine whether or not there were any remaining reserve potentials for that tract?

A. Yes.

Q. All right. Describe for me the method used.

A. Well, the remaining primary reserves of the current Premier well, the FV Number 3, is 5000 barrels, and that well has been shut in for at least a couple years.

Q. Now, you just took out production --

A. Right.

Q. -- and plotted the decline curve, and you had that value?

A. Right.

Q. But in terms of what you contend is no further primary reserve potential for the Premier tracts, how was that determination made?

A. It was determined by the same way we determined for the rest of the field where there was no primary production.

Q. And how did you do that?

A. As noted before in the flowstream methodology -- Let's refer to that.

Q. All right.

A. We used the original geologic model which provides a layering model, volumetrics, goes into a numerical simulator calibrated against the actual production results, and then it's used to determine economic primary, and if it's not economic it's of course not included.

Q. All right. If you'll turn to that portion of Exhibit 10 in Book I where we have Exhibit G-19, it's the exhibit part that follows the G narrative, where you're doing this stuff --

A. I'm not sure I understand the right area.

Q. Yeah, I'm looking for Exhibit G-19 --

A. Got you.

Q. -- out of the thick book. There's a spreadsheet there.

A. Got you.

Q. All right. Let's talk about how the work between you and Mr. Cantrell is organized, if you will. He's got a volumetric sum for the Upper Cherry Canyon. It's 107 million, give or take; is that not true? Original oil in place?

A. Something like that.

Q. Okay. Did you have as an engineer the ability to run material balance calculations on that reservoir container size to see if you could match back to that volumetric amount?

A. In effect that's what we do in a history match. When we're matching, it's actual production. We're not only matching oil rate, we're matching total fluid rate too, and we received a very good match.

Q. In turn -- In order to derive that number, what percentage of the decline rate -- or percentage recovery of original oil in place were you using?

A. I think that's shown in the technical report. I think it's G-18. It works out to five-percent recovery.

Q. All right, sir. When you look at calculating remaining recoverable reserves for the Premier tract, did you use the log-derived water saturation value for the FV3 as derived by Mr. Cantrell?

A. That was where we started initially.

Q. Okay. That initial value is determined by looking at one of these spreadsheets in the exhibit book, isn't it?

You can go to the E section of the book, and through all that tabulation of information there will be a corresponding value in here that will tell you the log-derived average water saturation for this well in the Upper Cherry Canyon is 0.385, all right? 0.385. Is that the value you used when you as an engineer calculated a remaining original oil in place for the Premier tract?

A. As I noted, we started with that value.

Q. Yes, sir.

A. But the key here is, we have a geologic model which is the start of determining future reserves. The key is, we have actual production available from this tract, and we can use that to calibrate the volumetrics in that area, and that's what we did.

Q. All right. In part of that calibration work you did, you adjusted the water saturation value in the calculation and you increased it to approximately 60 percent, didn't you?

A. Just under.

Q. And by increasing the water saturation value up to 60 percent, you are contracting the oil-in-place result from the calculation?

A. Correct, to match actual well performance.

Q. All right. Let's go back to G-19, Mr. Beuhler, and let's go through how this is put together.

There's the waterflood distribution map, Exhibit -- I lost track of the exhibit. Exhibit 25.

All right, Exhibit 25 gives us a code for going down the western boundary of the waterflood, and as we look at these various values, for waterflood purposes none of the tracts on the eastern value of the proposed unit are going to have any positive effect in contributing reserves for waterflood purposes; is that not true?

A. I think you're talking the -- tracts, and no, they will not contribute to the waterflood reserves.

Q. Okay. When we look at the unit well numbers on Exhibit G-19, that's a code that will help us locate where that well is --

A. Correct.

Q. -- or that 40-acre tract. It's a 40-acre tract code, is it not?

A. Correct.

Q. When we look at the first entry, 1109 is in fact the northeast-northeast of 25, right?

A. Correct.

Q. And for remaining primary, there is no value placed in that?

A. Correct.

Q. And that's how you -- and the method that you used to calculate that absence of remaining primary oil production was these production-adjusted values that you just described when you calculated oil in place?

A. Correct.

Q. All right. When you read over, you show that there's no workover value for that particular tract?

A. Correct.

Q. All right. What do you mean when you talk about a workover value for that tract?

A. These are workovers to capture behind-pipe pay that would be performed during the waterflood.

Q. All right. You can log-derive a potential by examination that there are existing wells that have not yet been adequately perforated, and they're still behind-the-pipe oil potential; is that what you're looking for?

A. These are workovers that will be done during the waterflood.

Q. All right. Look at the next tract down. It's 1111, which is the northwest-northwest of Section 30. It's where Yates has the EP7 well. Do you see that?

A. Uh-huh.

Q. It has a workover potential. What is this value? 266,000 barrels of oil?

A. Correct.

Q. How do you get that number?

A. That is derived from the hydrocarbon pore volume available.

Q. Okay. And delta is -- ? When you read over on the spreadsheet -- ?

A. Oh, yeah, delta is, in effect, the incremental of each step. The EUR adds each step, and the delta gives you the incremental.

Q. All right. I'm looking at delta, then, because I want the incremental reserves attributed to the waterflood portion for the workover, right?

A. Correct.

Q. And I get the 266 for that particular well.
When you go over and read it again for the waterflood part, there's additional contribution for waterflood, and how does that occur?
A. It's the same methodology as described before.
Q. In this instance, this well should receive some potential response from the injection well that's located to the south and east of this well?
A. Correct.
Q. Is that what is factored in here?
A. Correct.
Q. Okay. When you read on down the table and you get to the row that has 1709, on Exhibit G-19, that is the entry that corresponds to the FV3 well, does it not?
A. Right.
Q. And as you read across you've got the 5100; that's current cum on that well?
A. Uh-huh.
Q. We know what that is?
A. Uh-huh.
Q. But you show no incremental workover additional contribution for that well?
A. Right.
Q. And that is because of what?
A. Because it's not economic to go develop those

tracts.

Q. Based upon what?

A. Based on the available amount of waterflood and primary oil.

Q. Okay. That entire engineering analysis is based in the accuracy of Mr. Cantrell's geologic interpretation about the distribution of the reservoir pore volume in that tract, is it not?

A. No, in fact it's quite the opposite. We're able -- Because we have production available from people who have developed their tracts, we can calibrate that geologic model with actual production.

Q. And the calibration that occurred in the FV3 was to increase the water saturation, because you had water production from that well that increased the water cut, and therefore you attributed that water production directly to that interval in the well?

A. Water as well as cumulative oil, yes.

Q. And if that is flawed, then we have undervalued the Premier tract in terms of its value for remaining recoverable oil and any waterflood potential?

A. The history match to that tract would be based on what the well has actually done.

Q. Yes, sir. And if there's a mistake in that methodology or in that log analysis for that well, then there's going to be a mistake in failing to attribute recoverable reserves to this tract?

A. No, we're history-matching to actual production. It's the 5100 barrels that is the key thing here.

Q. And if the well has further potential beyond the 5000 barrels, then it's not incorporated in this analysis?

A. Correct.

Q. Okay. When we get to the $CO_2$ plan -- I've lost track of my exhibit numbers, Mr. Beuhler. What's the schematic that shows the --

A. Oh, it's about 27, I think, 28. The development plan?

Q. Yes, sir. All right, if we put this concept into operation, describe for me as a reservoir engineer the missing technical components that you need to make the decision about the $CO_2$ project.

A. Can you give further detail?

Q. Yes, sir. In response to Mr. Bruce, you said you needed more information with regards to the issue of whether you implement a $CO_2$ project, and that had to do with -- principally, I think, the missing ingredient was an injectivity test.

A. No, that was one of the things I said; I wouldn't say it's principally. That's an important economic parameter, certainly because that determines -- one of the things that determines how fast you can flood the field.

Q. All right, give me a list of what's missing at this point.

A. A complete list would be very difficult. I can give you some of the key ones, and I think the key one is being able to match against actual performance. And that's what we can do in the actual primary developed area, we have actual reserves that we can match against.

And so the key thing is, we have a better idea of what the $CO_2$ flood performance is in the actual developed part of the field.

As you extend beyond that, you don't have as much information, because the operator has not developed that area.

Q. All right. And the injectivity results that you're trying to see is whether or not water injected into an injection well is going to have a positive injection response in the pattern for the producing wells; is that what you're talking about?

A. No, the injectivity test I'm talking about is to determine how fast the $CO_2$ goes in.

Q. How will you determine that only within the context of the waterflood operation?

A. You can put it in any well.

Q. All right, and so the plan is to run a test with

$CO_2$ within the confines of a waterflood pattern?

A. That has not been determined yet --

Q. All right.

A. -- as far as which well we would predict -- we would pick.

Q. But that's the method. The method to determine the effectiveness of the injectivity of $CO_2$ is going to be to take an injector, or multiple injectors, from the waterflood and run that test?

A. It is to take a well that is injecting into the Delaware and put $CO_2$ into the Delaware and see how fast it goes in.

Q. Well, you're doing that now, aren't you? You don't have any of that capacity in this project at this point?

A. I don't understand.

Q. Well, you've got disposal wells. What zones are they disposing in?

A. Various zones, from the lower part of the Brushy to the upper part of the Cherry.

Q. All right. Can you run laboratory tests to determine the injectivity of the $CO_2$ in a project like this?

A. You could. You would always prefer well tests. That's the reason we want to do one.

Q. Do you have an analogy in another Delaware field where you could run the test to get the results to determine the feasibility of the $CO_2$ flood?

A. We do have analogies, but you'd always rather have one in the field of interest.

Q. All right. How soon could you start running that test?

A. I'm not sure. Right now the primary importance is getting the waterflood up and running.

Q. Anything else missing, to decide the feasibility of instituting the $CO_2$ project?

A. Number one is a nonreservoir issue. It's oil prices, prediction of oil prices.

Q. And what's your prediction? Is there a threshold prediction at which this is not feasible?

A. We don't look at it that way. It's -- When the working interest owners would be asked to make a decision, everybody would have to predict their own oil price and decide whether it was worth going for.

Q. Okay, anything else?

A. I think I've hit the significant ones.

Q. Describe for me the reasoning that you want to keep what appears to be 40-acre buffer of tracts that are not contributing to the waterflood project available as, I guess, an inventory of tracts for the $CO_2$ project. Why do you want to do that now?

A. Because we're looking ahead to a possible $CO_2$ project.

Q. That's it?

A. That's a good reason.

Q. The timing now is to put these tracts in now before you know if it's a feasible project?

A. As noted, it would be very difficult, we feel, to go back in and do something later on. It would require re-ratifications, re-approvals. It might not ever be done.

Q. You've never seen units expanded?

A. Of course they do.

Q. Were you involved in the working interest owner meetings back in June of 1994? Did you attend these things?

A. Yes.

Q. By unanimous agreement, the working interest owners excluded the Premier tract back in June of 1994, didn't it?

A. I think it notes that -- on the spreadsheet it says all working interest owners agree.

Q. And that included Exxon, didn't it?

A. Yes.

Q. And the technical information available at the time that that decision was made to exclude the Premier tract is no different than the information we have now, is it?

A. Well, you have to remember this was not a formal proposal being made. There was many issues being negotiated. This was just one of them.

Q. And as to this issue, the parties agreed to take the Premier tract out; is that not what this says?

A. Within that meeting, yes. But soon after that meeting Yates came back and said let's talk about this.

Q. And how was that done then? Was that on an agenda for a formal vote by the working interest owners, to now bring back in Premier who had just been voted out?

A. Once again, a formal proposal was never made to exclude Premier. This was another negotiation step.

Q. The decisions made about Premier were made between Exxon and Yates --

A. No.

Q. -- to the exclusion of Premier; is that what you're telling me?

A. No, no.

Q. Did you know that Mr. Ken Jones did not want his tracts in this unit?

A. At some point, yes.

Q. All right, sir. What changed between June of 1994 and now that caused these tracts to be put back in?

A. Well, like I said, very soon after June -- the June meeting -- Yates came back and said, We need to get the working interest owners together and decide what the unit outline should be.

Q. And based upon that, then, you brought back -- Because of Yates, you wanted the Premier tracts back in?

A. Yeah, there's important issues that have to be decided, like unitizing the entire pool, expediting efforts, things like that.

Q. If you exclude the Premier tracts from the $CO_2$, what's the consequence?

A. Those tracts probably would never be developed under $CO_2$, and therefore both the working and royalty interest owners would lose those reserves.

Q. Have you attempted to quantify what that would be?

A. I do not know that.

Q. Will the $CO_2$ project still be practical, feasible, and economic with the exclusion of the Premier tracts?

A. On all the other tracts, yes. You just exclude this tract and lose the reserves from those tracts.

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER STOGNER: Mr. Kellahin.

Any redirect?

MR. BRUCE: Just a few questions, Mr. Examiner.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. The last question, Mr. Beuhler, the $CO_2$ project could be done without Premier's tracts, but wouldn't reserves, future reserves, be lost?

A. Oh, yes, of course it would be a smaller project because you would lose those tracts.

Q. And you do map substantial tertiary reserves under the Premier tract?

A. Yeah, as noted it's one percent of the unit. That's a substantial amount of reserves.

Q. Now, regarding the so-called agreement to exclude Premier, as Mr. Kellahin characterized it, really wasn't that an agreement to consider excluding Premier?

A. Well, I think that's the whole point; it was never on the docket, it was a formal proposal to leave Premier out.

Q. So it came up at this working interest owners' meeting, people agreed to consider it, but there was no final action on that request?

A. Correct.

Q. And once again, really the unit outline you're proposing today is the same as it was in 1991?

A. Correct.

Q. A couple other points.
Mr. Kellahin asked you about the FV3 well, Premier's well in the southeast-southeast of Section 25. Does that well have any potential beyond its current cumulative recovery?
A. No, it's made 5000 barrels, and that's all it's going to...
Q. And on what do you base that?
A. Well, of course it hasn't made any in years, and a very analogous well is just to the south. It's geologically fairly -- very close, just to the south. It's -- As Mr. Cantrell has noted, it's the Citadel ZG Number 1, very similar in many aspects, and it's cum'd to date about 4000 barrels, and on current decline it might hit 6000.
Once again, it looks about the same, and it's going to give out the same amount of oil as the Premier well has.
Q. And one final issue. Mr. Kellahin was referring to Exhibit 10, the Exhibit G-19 of Exhibit 10, and he asked you about, I think, the top two wells, the Well Number 1109 and Well Number 1111.
A. Correct.
Q. Now, your treatment, Exxon's treatment in the technical report, say, Well 1109 in the northeast-northeast of Section 25 is no different than you treated similar

tracts. For instance, the northeast quarter, northwest quarter of Section 30, would be 1113. That was treated similarly to the Premier tract, was it not?

A. Correct, the methodology was all the same.

Q. And so the Yates tracts, the Exxon tracts, the Premier tracts were all treated similarly under those conditions?

A. Correct.

MR. BRUCE: I have nothing further, Mr. Examiner.

MR. KELLAHIN: A follow-up, Mr. Examiner.

EXAMINER STOGNER: Please, go ahead.

RECROSS-EXAMINATION

BY MR. KELLAHIN:

Q. If you'll look at Exhibit 28, Mr. Beuhler, do you see the lease line injection pattern here with the additional $CO_2$ injectors?

A. Sorry, I'm not there yet.

Q. All right, sir. I apologize for moving ahead. It's the schematic that shows the $CO_2$ development plan.

A. What exhibit number is that?

Q. Twenty-eight.

A. Thank you.

Q. Have you got it?

A. Yes, sir.

Q. All right. Look at the boundary between Section

25 and 30. The ability to recover the $CO_2$ reserves attributed to the Premier tract is made possible because of the location of those three injection wells along that section line; is that not true?

A. Correct.

Q. Are you familiar with the concept of cooperative lease line injection programs?

A. Yes, I am.

Q. And so you are accustomed to seeing this at least in waterfloods where adjoining properties would come together, each operator on each side would agree to participate in the injection wells, and as to the property or tracts on their sides, they get the benefit of that secondary or tertiary recovery plan?

A. Under waterfloods they are pretty common. Under $CO_2$ floods, I've never heard of one.

Q. But this pattern fits itself at least to the concept of a lease line cooperative plan where the Premier tracts can participate in some cooperative fashion without being included in the big unit?

A. From that one issue, yes.

MR. KELLAHIN: No further questions, Mr. Examiner.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Bruce?

FURTHER EXAMINATION

BY MR. BRUCE:

Q. Mr. Beuhler, what would Premier do with the produced $CO_2$?

A. That's a difficult question. That's why I make the point about it's common for a waterflood. I've never heard about it for a $CO_2$ flood.

That would appear to be a pretty big problem with water. Of course, everybody disposes of water, just about, but $CO_2$ flood requires pretty complex and expensive facilities to dispose of, and that would be pretty expensive for a small tract.

MR. BRUCE: Thank you.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Beuhler, while we're on this topic, this Exhibit 28, essentially 29, the earliest start would be 1999 for $CO_2$.

I don't see here any issues where the actual physical ability to inject $CO_2$ -- Is there a source of $CO_2$ planned for this area, or is there one in existence, and what would that entail?

A. There is no $CO_2$ source directly in the area. There would be the possibility of coming down from Maljamar to the north. There's another line from the south. That would, of course, be determined when we looked at this as we went.

But it would still involve the putting of a $CO_2$ pipeline into this immediate area.

Q. Would this project alone sustain the cost -- substantiate the cost to bring a line of $CO_2$ from the closest source, the Maljamar area, according to your testimony, in this, or would you have to have other $CO_2$ projects in the area?

A. We've always looked at it on a stand-alone basis. So yes, it would foot the bill for a $CO_2$ line designed for just this project. Of course, it might be larger to include other projects.

Q. Assuming that you had your waterflood, flood equipment and everything out there at that time, what additional equipment and how much -- has there been a cost estimate to drill the additional $CO_2$ wells?

And I guess once you got $CO_2$ breakthrough you'd need additional equipment on the producing wells, wouldn't you?

A. Yeah, the number that I testified previously to that it would require, like I said, more than $70 million to install a $CO_2$ project, that was the sum total of both the drilling and the facilities required to process the produced gas. It's pretty expensive as far as capital investments.

Q. Now, you assumed the economics, if I remember right, of a little over $17 a barrel with a five-percent increase or something?

A. Yes, sir, it starts at $17.10 and increases at 5.4 percent per year.

Q. Does that tie back into the 1999 date?

A. The 1999 date is purely looking at the reservoir.

Q. And not economics?

A. Correct.

Q. When you said -- or claimed or testified to Mr. Kellahin's cross-examination that you had never heard of a cooperative agreement with $CO_2$, are you saying in this state, or where you're familiar with in the Southwest?

A. In my experience, and that's in Texas and New Mexico.

Q. Would those wells actually be strict $CO_2$ injection wells, or would they be a water/$CO_2$ injection combination?

A. Yeah, I actually call them $CO_2$ phase injectors for a simplification. They would be what we call a WAG well, a water-alternating-gas well, if that looks like the best option.

Usually, most $CO_2$ fluids do alternate the injected $CO_2$ with some bank of water in phases.

Q. How is that initially kicked off? With $CO_2$ or with water, or do you follow through after six months of water or what?

A. Sometimes it's done on a time basis, sometimes it's done on a volume basis that's determined by the amount of pore volume you want to flood.

Usually you start off with a good slug of $CO_2$ maybe larger than your following slugs. Then you switch to water for conformance reasons and to put produced water away, then you switch to $CO_2$ back. But that initial slug is usually a larger volume of $CO_2$.

Q. In most of these proposed $CO_2$ injection wells, I notice that they're on the periphery. So if this was to occur, you would have some producing wells that would probably see some activity or response from the waterfloods, would you not? Those wells, those internal wells that -- producing wells.

A. Are you talking about the wells that were active during the waterflood?

Q. Yeah.

A. They would have already seen waterflood response, and now you're putting in $CO_2$.

Q. So you're backing up on the periphery, flooding $CO_2$ towards some wells that's already had some secondary recovery, but also the $CO_2$ miscibility or the $CO_2$ flooding is going out to, in some cases, virgin areas?

A. There might be some confusion. We would be putting $CO_2$ in all injectors within the pattern area. So those -- If you're looking at Exhibit 28, the wells that are shown as wells that would be drilled for the water injection phase, we would also be putting $CO_2$ in those wells.

So it's a full 40-acre inverted fivespot flood. I might have confused you there.

Q. Okay. So the wells with -- The blue water injection wells, if the $CO_2$ injection proceeded, you would have these wells in place and then start flooding all injection wells with $CO_2$?

A. Yes, sir.

Q. Quite a substantial volume, is it not?

A. Of $CO_2$?

Q. Yes.

A. Oh, yes.

Q. Has Exxon had any experience with Delaware $CO_2$ injection?

A. Not Delaware. The other two Delaware floods that have been operated in the past are two Freds -- It's been operated by several people and then Conoco's --

Q. What was the first one that you said?

A. Two Freds, sorry. It's in Loving County, Texas.

Q. Loving County.
A. Both these are Texas.
Q. Two Freds, like in Fred Flintstone?
A. Right, exactly. I think it was operated by HNG during most of its flood.
Q. Do this -- Those ones that you had mentioned in Loving County, Texas, were they of the same scope? Are they smaller or larger?
A. Areally, they're about the same size. They're thinner reservoirs, and therefore smaller total recoveries.
EXAMINER STOGNER: Any other questions of this witness? You may be excused.
Mr. Bruce, do you have --
MR. BRUCE: That concludes my direct presentation, Mr. Examiner.
EXAMINER STOGNER: You don't wish to recall anybody at this time?
MR. BRUCE: Not at this time, no.
EXAMINER STOGNER: Mr. Carr, would you like to present your witness at this time?
MR. CARR: Yes, sir. Can we take just about five minutes to set up?
EXAMINER STOGNER: Let's take a five-minute recess then.
(Thereupon, a recess was taken at 3:27 p.m.)

(The following proceedings had at 3:45 p.m.)

EXAMINER STOGNER: Hearing will come to order.

Mr. Carr?

MR. CARR: May it please the Examiner, at this time we would call David Boneau.

DAVID F. BONEAU,

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. David Francis Boneau.

Q. Where do you reside?

A. Artesia, New Mexico.

Q. By whom are you employed?

A. I'm employed by Yates Petroleum Corporation.

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

A. My current position is called manager of non-operated properties.

Q. By training are you a petroleum engineer?

A. I have been trained and worked as a petroleum engineer for many years.

Q. Have you previously testified before this Division?

A. Yes, sir.

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 Exxon-proposed statutory unit in the Avalon-Delaware Pool?

A. Yes, I am.

Q. And are you familiar also with the plans to waterflood and ultimately $CO_2$ flood this unit?

A. Yes, sir.

Q. Did you participate for Yates Petroleum Corporation in the negotiations which resulted in the proposed unit agreement and the proposed unit?

A. Yes, I have negotiated with Exxon and the other people in this unit.

Q. Are you familiar with the proposed unit areas and the wells located therein?

A. Yes, sir.

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

EXAMINER STOGNER: Any objections?

MR. KELLAHIN: Oh, not to Dr. Boneau.

EXAMINER STOGNER: Dr. Boneau is so qualified, Mr. Carr.

Q. (By Mr. Carr) Dr. Boneau, would you briefly state what Yates' purpose is in participating in this hearing?

A. Yates' purpose in participating in this hearing is to support the Application of Exxon for the unit and the waterflood and the proposed operations in this area.

And the reason we're here is that we participated through a lot of the preliminaries that led up to this day, and we're able to give a story that's not the Applicant and not the opposing people; it's another observer that was there the whole time.

Q. Now, Dr. Boneau, have you prepared certain exhibits for presentation here today?

A. Yes, sir.

Q. Let's go to what has been marked as Yates Petroleum Corporation Exhibit Number 1. Would you identify that for Mr. Stogner, please?

A. Exhibit Number 1 is a single piece of paper that summarizes what our purpose is in being here.

I have three points to make in the presentation, and those are listed.

The first is that Yates argued with Exxon a lot, and you'll see that "a lot" covers quite a number of issues.

The second point is, after more than two years of negotiations, we have come to an agreement with Exxon, and that is a fair agreement. And as a result of all that work, Yates is now in a position to support the unit, and that's why we're here.

And the third point I wanted to make is to essentially remind the Examiner to please go back and look at NMOCD Case 10,145 that occurred in 1990. I was the Applicant for Yates Petroleum in a GOR case in the Avalon-Delaware field, and Premier opposed that and promised some things that may or may not have been done.

Q. All right, Dr. Boneau, let's go to the first point, Yates arguing or negotiating with Exxon, and I would ask you to refer to Exhibit Number 2 and explain what Exhibit Number 2 is designed to show.

A. Okay, I've divided our arguing with Exxon, negotiating with Exxon, into three separate issues.

The first of those issues is talked about on Exhibit Number 2, and that's where we discussed with Exxon the technical report. And there's a chronological on Exhibit 2, and you may note off to the right side of Exhibit 2 there's some notations to Exhibits 2-A, 2-B, et cetera, and those are letters and correspondence that are contained in these red books.

Q. And the correspondence indicated on this Exhibit 2-A through 2-G is what has been marked as Yates Exhibit

Number 6; is that right?

A. That's correct.

Q. And then the remaining of the correspondence supporting the next two pages, or the next two exhibits, is what has been marked Yates Exhibit 7?

A. Yes, sir, that's correct.

Q. Now, initially negotiations took place concerning the technical committee report; is that correct?

A. Yes, you've heard Exxon describe how the -- their technical report, a big fat book with a large book of maps, came into existence, and it's labeled, I think, August, 1992.

But in -- As my first point says, in September, 1992, they sent that out to the owners of the tracts in the proposed unit, and I suddenly had a big fat book on my desk to read.

Q. Had Yates been involved with the development of the technical committee report prior to that time?

A. We knew that -- As Exxon stated, we knew that they were working on this, and they would send us a map of the proposed area, and we were inside that area, we knew that they were working on a technical committee.

Frankly, I didn't realize they were going to come with such a detailed and concise study. But they came with this big book, and it arrived about September, 1992.

Q. Was it agreeable to Yates for Exxon to go forward and prepare the technical committee report without the involvement of Yates Petroleum?

A. Yes, that was agreeable to Yates.

Q. Could you review the negotiations between Yates and Exxon concerning the technical committee report?

A. Yes, sir, that's my intention. When that report arrived, I read it and an engineer that works with me read it.

There were some things in it that we thought were -- incorrect, actually, is what we thought, and we figured that we were the second biggest owner after Exxon. And we contacted in November Coquina, who was the third biggest owner.

To confuse the Examiner, the Coquina interest has been owned by -- like a rubber ball. It was Coquina, then it was ANP, then it was Patrick, and now it's the Unit Petroleum people that are here.

But they are -- That interest is the third biggest interest in the unit.

I contacted the Coquina people and told them our concerns and ended up convincing them that they should be their concerns too.

Then in item number 3, later in November of 1992, I wrote a letter to Exxon with our reactions to the technical report. And the two main things we didn't like are what's listed there. In shorthand, it's listed.

My main concern was that Exxon was proposing to send the owners an $80 million AFE for a $CO_2$ flood without doing a pilot or without regard to whether it worked -- it failed the first month or not. They were going to go spend $80 million without looking back. And as an independent to which $80 million is a lot of money, we didn't think that was the most prudent approach.

And the other thing we didn't like about their report was that they had -- We thought that the reserves that they had ascribed to four wells were incorrect, and they were incorrect such that they hurt Yates and benefitted Exxon.

We brought those things and a couple other minor items to Exxon's attention.

Then shortly after that, in December, we got -- we went to Midland to talk with Exxon about the report, and they explained in detail what they had done, and we tried to tell them what our concerns were.

And as a result of that meeting, on December 22nd, 1992, Exxon sent us revised reserves for -- not four wells but five wells. They had adjusted the four wells more or less the way we wanted, but they found one other one to change that benefitted them, and they stuck that in too, which was really kind of clever.

But they did address the issue of the reserves.

Q. Were there any other working interest owners at that meeting?

A. My memory is that there were not.

Q. Okay. And then what happened?

A. The after Christmas, I wrote back to Coquina a big long letter explaining all the things that had been done and where we stood with Exxon. And where we stood was that we still didn't -- I think I used the word -- you know, Exxon's approach is crazy, is what I think I said in that letter, regarding the $80-million AFE.

And so eventually in February Exxon proposed -- Well, it makes sense. They didn't want to redo this whole great big book, and their approach was, can we make a couple pages of amendments in critical points so that we can get it right, but not republish this gigantic book? And so they proposed some changes to the language regarding the implementation of the $CO_2$ flood.

And then a couple of weeks later in March, we sent back a counterproposal kind of draft. And by April 15th we had reached a point where there was -- I think there ended up being four pages of revisions or of amendments to the agreement that were acceptable to us and that Exxon would add to the technical report.

And that's what was accepted as the final technical report, that big fat volume, plus these few pages of amendments.

Q. Basically, what happened was, Yates' working interest owner expressed concern about the technical committee report to Exxon, negotiations took place, and that report was revised; is that fair to say?

A. Yes, that's the short of it.

Q. Let's go to what has been marked as Yates Petroleum Corporation Exhibit Number 3. Could you identify this, please?

A. Yes, Exhibit Number 3 is a longer chronological -- a longer history of our negotiations with Exxon over the ownership formula, over the -- what you would call the participation formula, the formula that tells how much of the unit each tract and each working interest owner owns.

And the discussions over the technical report were just a preliminary to this. This is when what I consider the important stuff started.

Q. Does a break of almost a year between the discussions on the technical committee report, ending in April of 1993, and discussions concerning the ownership formula -- Do you know why there was that kind of break in the chronology?

A. I think I found out later that what happened was that Exxon spent a lot of time after they got the technical report approved making agreements, and deciding internally their proposal for the ownership and the operation and the various details of the agreement, and they must have gone through a huge procedure to do that.

But they came in April of 1994, saying -- with a notice for a meeting, but saying that Exxon has really studied this, and Exxon has an excellent and detailed proposal to present to the working interest owners, and please come hear about it.

I think that it just took them that long to get the fat agreement and the detailed -- and kind of different proposal that they came with, to get it together. I think it just took them a while to get it together.

Q. Did you attend the April 26th, 1994, meeting?

A. Yes, I attended it. I think all the parties involved here attended it. I think Premier and of course Exxon attended it.

And at that first working interest owners' meeting -- Like I said, the purpose was, come and hear what Exxon has to propose. And it took several hours to hear what Exxon had to propose.

And what they proposed was a two-phase formula where Phase 1 consisted of the remaining primary and the waterflood, and Phase 2, if it happened, was the $CO_2$ flood, and the ownership that they proposed was based on the present value, based on economic calculations of a dollar value of the oil to each owner done at a 20-percent discount.

There were -- well, there were -- very detailed, a long list. But those were the main things. It was different from the -- what we ended up with in the usual agreement where you talk about primary reserves, $CO_2$ reserves, waterflood reserves.

They talked about the dollar value of the primary reserves, waterflood reserves, $CO_2$ reserves, via some economic calculations that they couldn't tell you the details of because they were proprietary company secrets. Anyway, it was a different proposal.

And we heard it out. And we went home and said, There's some things about that that's got to be changed.

Q. Okay. What was the next thing that occurred?

A. Well, the next thing that occurred was kind of a sidelight that's very important to this hearing.

At the end of that April 26th meeting, I believe it was Mr. Mayhew, but the Exxon representative came up to me and said, Premier has come and they've got some real concerns about the picks on the logs and these wells out on the west side, and we'd like to get the geologists together to meet. Would Yates be willing to come to a meeting to discuss just the geology of those well logs?

And on May 4th they actually sent us an agenda for the meeting, but I knew about the meeting at the end of the day on April 26th.

I went right home and talked to the geologist who worked in my group at Yates, and that's a lady named D'Nese Fly, who doesn't work for Yates anymore, but told her about this meeting coming up and told her that she needed to study it for the next two weeks and figure out whether she agreed with the Exxon or the Premier view of the logs.

So the next thing that happened between us was on May 13th there was a meeting in Midland, and the attendees were Premier, Yates and Exxon. And the topic was geology. It was these logs, specifically, the FV3 and the logs in that area.

And the other people can -- Well, Premier presented how they viewed the logs, and Exxon presented how they viewed the logs.

And D'Nese had spent these two weeks looking at the logs and the associated geology. And towards the end of the meeting, the people asked me, What is Yates' position on this?

And I said, Yates' position on this is whatever this lady geologist tells you that Yates' position is. And she said her two weeks of study --

MR. KELLAHIN: I'm going to object to Dr. Boneau testifying about what D'Nese Fly has concluded about the geology. It's an out-of-court statement offered to prove the matter asserted. Ms. Fly needs to be present to be cross-examined.

It's inappropriate for Dr. Boneau to put a geologic position on his company through an absent witness.

EXAMINER STOGNER: Mr. Carr?

MR. CARR: I think I can handle this without asking Dr. Boneau to testify about what D'Nese Fly stated, if I can ask him several questions.

EXAMINER STOGNER: I think that would be appropriate.

Q. (By Mr. Carr) Dr. Boneau, you attended the meeting on May 13, 1994, with representatives of Exxon and Premier, did you not?

A. Yes.

Q. And attached in Exhibit 7 are the notes of that meeting; is that correct?

A. Yes, there are notes of that meeting.

Q. And they are included in Exhibit 7 as Exhibit 3-D; is that correct?

A. Yes, sir.

Q. And also there are comment letters as a result of that meeting that are included in Exhibit Number 7 as

Exhibit 3-F -- or --

A. No, you're misreading.

Q. 3-D and 3-E are the documents; is that correct?

A. No, 3-E is not related to that meeting.

Q. All right. So only 3-D are the notes --

A. Only 3-D is related to that meeting.

Q. And what are those, without going into the details? 3-D is what?

A. 3-D is an agenda of the meeting, some notes from Exxon on the meeting, some notes from Premier on the meeting.

Q. And are these notes from the business records of Yates Petroleum Corporation?

A. Yes, sir.

Q. And is it the normal course of Yates Petroleum Corporation to keep notes of this nature?

A. Yes, sir.

MR. CARR: I would move the admission at this point in time, Mr. Stogner, of Exhibit 3-D. It's the business records of Yates Petroleum Corporation, and it is an exception to the hearsay rule, Rule 807, and they may be admitted as such.

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: One moment. May I ask Mr. Carr where he is in this?

MR. CARR: Yeah, it's Exhibit 7, Tom.

Q. (By Mr. Carr) Dr. Boneau, can you turn to -- can you take out the book which is Exhibit 7, please, and can you --

A. Pull the tab that says 3-D.

Q. And can you identify for us what you have described as the notes from the UCC meeting, this Upper Cherry Canyon meeting? Can you identify those, please?

A. The first page of 3-D says Proposed Avalon-Delaware Unit Technical Report Discussions.

Q. And the material behind this tab, these are the records of Yates Petroleum Corporation?

A. Yes, they are the records of Yates Petroleum Corporation. They came from handouts at that meeting.

Q. And these were prepared on or about the time of that meeting?

A. The pieces of paper that are there were prepared by Exxon or Premier for that meeting.

Q. And are these documents that are kept by Yates as part of its business records?

A. Yes, sir.

Q. And is it -- In the ordinary course of Yates' business are records of this nature kept in its files?

A. Yes, sir.

MR. CARR: I move the admission of the documents behind 3-D.

MR. KELLAHIN: No objection.

EXAMINER STOGNER: So admitted.

MR. CARR: And those documents, Mr. Stogner, we submit, speak for themselves, and we will move on in the presentation.

EXAMINER STOGNER: Thank you.

Q. (By Mr. Carr) Dr. Boneau, I'd like to go to what is item number 5 on Yates Petroleum Corporation Exhibit Number 3.

A. Yeah, let's get back to the main story.

Q. All right.

A. The main story was, we didn't like their ownership formula.

Q. All right. What happened at that -- Following the UCC meeting, what happened?

A. At the original working interest owners' meeting, we heard Exxon's presentation, and the idea was, people would go back and react to that, and then the working interest owners would reassemble and talk about the reactions to the Exxon proposal.

That meeting -- Well, the first meeting generated some comment letters from Premier, Yates, Hudson, Whiting, ANP, various people, about things they didn't like about the Exxon proposal.

And the working interest owners reassembled on June 17th, 1994, item number 6, and most of that meeting was spent discussing Yates' list of reactions, of things we didn't like about the Exxon proposal. And I've listed the main things there.

We didn't like the ownership formula, we didn't like what Exxon proposed for the voting percentage that was required to approve an AFE, nobody liked their overhead rates of $725 a month. Things like that.

Yates -- I was there with a couple other Yates people, but I did most of the talking, and we discussed why we didn't think the ownership formula was fair. The ownership formula proposed by Exxon gave Yates 9.8 percent of the unit in this Exxon Phase 1, which was the primary in the waterflood. It gave Yates about 11.5 percent of the unit in the $CO_2$ phase.

The numbers from the technical report are that Yates has a little less than 8 percent of the primary reserves, Yates has 14 percent of the waterflood reserves, Yates has 12 percent of the $CO_2$ reserves, and we didn't think that 8 and 14 and 12 added up to 9.8. From our position, those are the numbers.

The other people there felt similar. I tried to lay out why we thought the Exxon formula was giving too much to Exxon and not enough to the other people, and I did that.

The result of that meeting -- and I -- And at that meeting, I told Exxon that Yates preferred a one-phase formula, if possible.

And the result of that meeting was that Exxon stuck me with the job of coming up with a suitable one-phase formula, and I went home and actually tried to do that.

And item number 8 is a draft of an internal Yates memo discussing what turned out to be Yates' proposal A.

Q. And what did you do with that proposal?

A. I talked about it with Peyton Yates several times, but it's not a one-phase formula. The more I looked at it, the more I decided that the logical division was to break it into a primary phase where Yates and the other people had a relatively small interest, and Exxon has 80 percent of the remaining primary reserves, and separate that from everything that would come after it, from the waterflood and $CO_2$.

And so the proposals that I came up with were really two-phase, or where the first phase was a very short phase representing the remaining primary, and Phase 2 was starting with the waterflood on. And the idea was, Yates would accept a small interest in Phase 1 in the near-term operation, because we had a small part of the remaining primary reserves, but we should have a -- around 12 percent or so of the waterflood and $CO_2$, because that's what the report said we had of the reserves.

So item number 8 is an internal Yates memo, and a -- I think there's actually two of them there.

And then on September 6th of 1994 I sent to Exxon what I'm calling Yates' Proposal A that was approved by the Yates management, and it does the kind of things that I'm talking about.

Phase 1 is only the primary. We proposed that the Phase 2 owners pay all the capital costs, right from the start, and that meant that at the start of the flood Yates would be paying 12 percent of the cost and getting 7 or 8 percent of the income, but we thought that was fair.

Those are the two main things in the proposal that we sent out.

Q. And what sort of a response did you receive from Exxon?

A. Exxon did not make a counterproposal. They responded and said, Your proposal causes other problems. They responded with what I would call questions.

And one of the main things they responded with was that charging the capital costs the way I wanted to do, which benefitted Exxon, hurt Premier. Okay, I guess I should say the original Exxon proposal, you know, way back in April, gave Premier zero, until the end of the waterflood.

My proposal included $CO_2$ reserves in both Phase 1 and Phase 2 and therefore gave Premier some interest right from the start.

But what Exxon pointed out was that Premier would be paying four times more for capital in the early part than they were getting in the income. And Yates was willing to accept an 8-to-12 ratio but Exxon wondered whether Premier would be willing to accept a 1-to-4 ratio.

Anyway, we talked about problems with -- Well, I hate to say "problems with our proposal", but they were problems with our proposal.

Q. All right. And that takes us to --

A. That takes us to 10 and 11.

Q. All right.

A. And then as a result of those meetings, I got Yates' management to approve a couple other proposals that were kind of similar in that they were two-phase, but we addressed the problem of Premier paying more than they were getting by creating what I call a special Phase 2 owners, where the idea was that Exxon and Yates would lend these excess capital costs to people like Premier at zero interest, so that they could not have huge bills at the start, but we could still give Exxon the benefit of us paying for the cost of the waterflood that was really going to benefit us.

And these new proposals included detailed things on overhead where we didn't mind paying high overhead during the $CO_2$ flood, but during the waterflood we thought the overhead should be lower.

We gave them a comprehensive proposal there in December.

Q. And what was their response?

A. Between Christmas and New Year's, they called me with a counterproposal, and this was the first time that Exxon had actually made a counterproposal, and I was hallelujah'ing about that.

And I wrote up internal -- the differences between where Yates was and where Exxon was, and we were getting pretty close. In fact, over a series of -- We're now down to item 14 or so. Over a series of phone calls during that time, Mr. Mayhew and myself, talking with Yates' management, came to the point where we had a two-phase formula that we were willing to accept.

And when Mr. Mayhew took that to his management and went through it, at least the report I got from him was -- He called me up and said, You won't believe what happened; my manager wants us to go to a one-phase formula that does this and this and these other things.

And I said, I can make a one-phase formula that does that. And in item 15 I sent him a one-phase formula which has the shorthand that's listed there. It was 23 percent primary reserves, 47 percent waterflood reserves and 37 percent $CO_2$ reserves.

And the response I got back from Exxon was a letter that recommended the 25-50-25 that we -- that appears in the final agreement.

Q. So is it fair to say that as to the ownership formula that is in the unit documents, that over a nine-month period of time Yates and Exxon were in active negotiation, trying to develop a formula that would be acceptable to the working interest owners in this unit?

A. Yes, that's fair to say. And it's fair -- I think it's fair to say that the final result is fair. We think it's fair. Our interest went from 9.8 percent to 12 percent. Premier's interest went from zero to one percent.

And yes, it accomplished, in terms of ownership, the goals that got us to the items that I laid out in June of 1994 at that second working interest owners' meeting. And six months later, we had an agreement that accomplished the major goals that I thought that Yates should have, and the other people that were in more or less the same position as Yates.

Q. Now, Dr. Boneau, let's go to what has been marked as Yates Petroleum Corporation Exhibit Number 4. Could you briefly review this exhibit?

A. Hopefully this one can be briefer.

Exhibit Number 4 is a similar kind of chronology for the third set of negotiations with Exxon. I thought after we had the ownership formula fixed that we were in good shape, and I was wrong.

The last item on Exhibit 3 was January 19th, 1995. And on January 31st, 1995, I received written from Exxon a letter laying out the proposed changes to the original Exxon proposal that Yates and Exxon had agreed upon, and it had the formula like we had agreed, et cetera.

But it had a procedure for voting on AFEs that shocked me, basically, that -- and my reaction was, as I wrote, the voting procedure stinks. And what Exxon had proposed was that they own about 73 percent, 73-and-a-fraction percent, and they wanted anything to be approved by less than 76 percent, so they needed only like 2.5 percent additional people to approve anything.

And Yates' concern was that this was a really expensive project, and we thought that big expenditures should be subject to kind of a supermajority vote, that the minority -- we didn't mind having little say on workovers and the more or less normal operations. But when you're going to go out and spend $14 million or $40 million or $80 million, we thought that there needed to be a voting procedure that let the minority people have more of a say than Exxon was proposing.

Q. Okay, and what happened?

A. We paid a lot of fax bills, I think.

Q. And what was the result of that?

A. Exxon -- Yeah. We sent Exxon proposals, and they sent proposals back to us. And we got a committee of five Yates people together, and we had a -- five different things to send them every day, that they found confusing.

Finally, about February 22nd, there's a memo that -- where Exxon says, I'm at my limit on this. And my return says, this is as far as Peyton will go. And we were still, you know, more than a millimeter apart.

And Mr. Mayhew, I think, took those two things to his manager and worked them out and sent us back a letter saying that in a spirit of cooperation, we'll compromise in these areas.

And we ended up with a voting procedure where the big expenditures require 85-percent approval and the smaller expenditures require the approval that Exxon proposed.

Q. Now, Dr. Boneau, the second matter on Exhibit 1 is a statement that a fair agreement was reached, and Yates supports the unit as proposed by Exxon. Can you explain that, please? Upon what do you base that statement?

A. I have two ideas involved in calling it fair.

I very much believe that the whole reservoir should be included in the unit, so that you don't have problems down the road and so that you can really operate on the whole reservoir. And so I was -- I did not like at all that the original Exxon proposal -- it gave nothing to these ring people until you got to the $CO_2$. And so all my proposals involved bringing Premier and these -- what I called the people in the ring into the unit.

And the final proposal, the final agreement, had those people in from the start, they had Premier at one percent.

My other idea of fair was that the ownership that we got when it was commensurate with our portion of the primary waterflood and $CO_2$ reserves -- which were 8, 14 and 12 percent, and like I said, I didn't think 9.8 was a fair average of those but that 12 was a fair average of those, and we got to an agreement where Yates got 12 percent of the unit, based on having 8, 14 and 12 percent of the component reserves.

Q. Is it your testimony that the formula in the unit documents is fair to Yates?

A. It's my testimony that the agreement is fair to Yates.

Maybe the Examiner -- Maybe I didn't make it clear. There's a real clear division of ownership in this where some wells are owned 100 percent by Exxon and the other wells for the most part are owned by a group of people that includes Yates and Coquina.

And so there were a group of people that were in the same boat as Yates. And if the agreement could be made more fair for Yates, it was automatically made more fair for a long list of those owners, those non-Exxon owners.

Q. In your opinion, is the agreement fair to that non-Exxon owner list?

A. Yes, it's my opinion that it's fair to that non-Exxon owner list and that it's fair to the ring people. And Exxon is big enough to take care of itself, and so I think it's fair to Exxon.

Q. Is it fair to Premier?

A. Yes, they're one of those ring people. They're probably the biggest of the ring people.

Q. Now, Dr. Boneau, the third item on Exhibit Number 1 states that Premier promised Delaware development by 1991. Can you explain what you mean by that statement?

A. Yes, I'll attempt to do that, briefly, hopefully.

In November of 1990, I appeared before -- Jim Morrow, actually, was the hearing examiner, in Case 10,145, seeking to increase the GOR. You heard testimony today about how the GOR has risen to about 3000. The GOR in the normal statewide rules is 2000, and there was a need to increase it, and Yates had pretty solid engineering data to support that.

Anyway, Premier opposed that application. And Larry Jones, who has since died, was the person who testified. And his testimony -- part of his testimony essentially said, I've had this lease since July of 1990, it's now only a few months later, you're doing something that's going to affect me, and I haven't had time, really, to develop my lease and I'm going to develop it within the next year. And he made that statement a couple times.

I think it hasn't happened, but -- And we haven't heard from Premier yet, but they talked about developing this lease in 1990, and they're going to talk about it, I guess, again tomorrow. And you just need to remember the transcript from Case 10,145.

Q. Now, Dr. Boneau, you were present this morning when there were discussions with the land witness for Exxon concerning minutes of the June 17 working interest owner meeting, were you not?

A. I was here, yes, sir.

Q. And you were present when there was a discussion about actions taken at that meeting concerning whether or not the interests of Premier could or should be excluded from the unit area. Do you recall that conversation?

A. Yes, sir, I recall that.

Q. What has been Yates' position on the inclusion of the Premier acreage in this unit?

A. Yates' position has always been that the entire reservoir needed to be unitized, and all the -- like I say, all the formulas I proposed included -- including that entire reservoir, Premier and everybody in the reservoir.

At that meeting on June 17th, there were discussions about the Premier acreage, and people agreed that it would solve the problem, that you could go ahead by omitting the Premier acreage.

But I was -- I agreed that that was a possible solution, but it was always a position that I was opposed to. I take exception to saying that I agreed to taking them out. I never agreed to take -- Yates never agreed to taking them out.

Q. Is it your recollection that this acreage was ever voted out of the proposed unit area?

A. No, it was never voted out of the proposed unit area, and I went home from that meeting and immediately started preparing formulas that included Premier in the unit.

Q. If that acreage is excluded from the unit area, what will the impact ultimately be on the unit operations?

A. If that acreage is excluded, we're back to square one, or we're not even up to square one. If that acreage is excluded, obviously, we lose the reserves that exist between the westernmost Yates wells and the Premier acreage. There's no way to get those without an injector over there.

Worse than that, we've got to renegotiate who owns the shrunken unit, and Yates will be credited -- or Yates and its partners will be credited with fewer $CO_2$ reserves, and Exxon's going to want us to lower our interest in the unit, and we're not going to want to lower our interest in the unit, and we're going to be back fighting again.

The reason that concerns me, I think that this is really a very important unit to get started in southeast New Mexico, for a couple of reasons.

It's the first unit, including Brushy Canyon and Cherry Canyon, to be put together for waterflood, and there are a bunch of other Delaware fields out there in Sand Dunes and Livingston Ridge, et cetera, that are looking to this flood to be a prototype and a leadership role in developing those other Delaware reserves.

I'm real happy to have Exxon involved in this first flood. Exxon has fantastic technology, and if we're going to get a successful $CO_2$ flood Exxon are the people to bring the technology so that it works.

Exxon are the people to bring a $CO_2$ pipeline down there. If we can get that, there will be other fields that are developed.

There is just so much potential riding on this flood, and we'd be back to square zero. I really don't want this unit to fall apart.

Q. Comments have been made today during testimony or questions asked in which it's been suggested that the Premier tracts are of no value to the unit. Do you concur in that?

A. No, I disagree with that idea entirely, and all the proposals that I've made for formulas gave value to Premier, to the Premier wells.

The Premier wells are valuable because they serve as host of $CO_2$ reserves and as site of injection wells, to push those $CO_2$ reserves to producing wells, some of which are on acreage operated by Yates.

Q. If this acreage is not included, will the ultimate recovery from this unit be affected?

A. Yes, very much so, because there's about four or five million barrels of reserves on those westernmost tracts operated by Yates, and you're going to lose, you know, two million or more of those barrels for sure.

Q. And will those be wasted?

A. They will not be recovered, and they could have been otherwise. That's called waste, yes, sir.

Q. Do you have anything further to add to your testimony?

A. No, sir.

Q. Were Exhibits 1 through 7 prepared by you?

A. Yes, they were prepared by me.

Q. Or compiled under your direction?

A. They were prepared by me. A lot of them consisted of gathering up papers that other people have sent me or I've sent other people. Yes, they were prepared by me.

Q. And the papers that you've gathered together and have included in Exhibits 6 and 7, are those from the business records of Yates Petroleum Corporation?

A. Yes, sir, they are.

MR. CARR: At this time, Mr. Examiner, I move into evidence Yates Exhibits 1 through 7.

EXAMINER STOGNER: Are there any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Exhibits 1 through 7 will be admitted into evidence.

MR. CARR: And that concludes my direct examination of Dr. Boneau.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Bruce, your witness.

EXAMINATION

BY MR. BRUCE:

Q. Just one question, Dr. Boneau. The May 13th, 1994, meeting, at the conclusion of that meeting did the Yates geologists agree with Exxon's geologists?

A. Yes.

MR. BRUCE: Thank you.

EXAMINER STOGNER: Mr. Bruce.

Mr. Kellahin, your witness.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Dr. Boneau, I need you to refresh my recollection of some of the chronology early on in the unit process.

Exhibit 7 from Exxon shows some entries back in 1991. The very first entry is a May 29th, 1991, entry where it says the working interest owners, apparently at Exxon's request, had a preliminary meeting. Were you involved in this process for Yates back that far?

A. My memory is yes.

Q. And so you would have been Yates' representative back in May of 1991?

A. I attended that -- My memory is, I attended that meeting and one or two other Yates people attended that meeting.

Q. Do you recall if Premier was at that meeting?

A. I do not recall.

Q. Was that the meeting in which the working interest owners that were present decided that they would accept Exxon's offer to use Exxon's technical personnel to prepare or begin preparing a technical report?

A. My memory is yes, but I haven't looked at that letter recently.

Q. I was trying to fit in where you had said earlier that Yates had agreed to let Exxon's technical people prepare the report.

Is this the May of 1991 meeting that we're talking about?

A. I think so. The chronologies I did prepare were too lengthy anyway, and I tried to omit that early stuff. But yes, my memory is in agreement with your statements.

Q. Was there a technical report generated by Exxon's personnel that predates this August, 1992, book that we're looking at today?

A. Not as far as I know.

Q. Okay. Then the next meeting that's shown on the Exxon chronology is this November 20th of 1991. There's a second preliminary meeting on a technical discussion and project plan. Were you at that meeting?

A. I think so.

Q. Do you know whether or not there was any technical report presented at that meeting back in 1991?
A. I know there was no technical report in the sense of a bound or unbound group of papers. There was some -- what shall we call it? -- Exxon handouts.
But no, it was not what you would call a report; it was some preliminary papers about production, and here's an area that looks like it has a common reservoir.
Q. Do you know if Premier was involved in that meeting back in November of 1991?
A. I'm sorry, I don't remember.
Q. At what point in this chronology did you examine the reserves attributed to the Yates tracts and request that there be adjustments made in those reserve calculations? I believe you mentioned four tracts?
A. Four wells, yes, sir. There were no -- My memory is, there were no hard numbers until the technical report dated August, 1992, came into existence.
Q. All right. And so it is that report, then --
A. It is that report that has reserves in it, well by well reserves, and we disagreed with the primary reserves assigned to four wells, two Yates wells that we thought they had given too few reserves to, and two Exxon wells that we thought they had given too large reserves to.
Q. Do you recall how Exxon had calculated or

formulated their conclusion about their reserve calculation for those wells?

A. We got the report with the associated verbiage, and we did reserves independently, and we got different numbers.

We told Exxon that we had -- we had different numbers, and the numbers we had made sense in our head, and their numbers didn't make sense, and we went and -- we told them that we didn't agree.

We went to this meeting, and they explained how they had done it in detail at that meeting. It involved GOR limits and rate-versus-cum curves. It involved them setting up a procedure, a rather elaborate procedure, and what I would call slavishly applying it to every single well, and it turned out that we thought that the GOR limits that they had assumed were unreasonable for these few wells, and -- you know, as a result of this meeting we saw a reason why they had a different number than we had. And at least in a couple of the cases, I thought we convinced them that -- go look at the production of this well, and your number is unreasonable.

Q. Are those amendments reflected now in the documents that we received today, whereby --

A. Those amendments -- There are three or four pages of amendments to the -- what I'm calling the technical agreement, and at least one of those pages is a relisting of the reserves, well by well, and it has different numbers than the original report for at least five wells, four of those being the ones that Yates brought up.

Q. All right. If I showed you a copy of Map 1, which is simply the index map, would you be able to identify the four Yates wells or tracts for which there was reserve adjustments?

A. I don't think so.

Q. You wouldn't be able to do that? Is there any way to document which tracts were adjusted in terms of reserve? Perhaps we could do that at the break if there's --

A. Yeah, the only way to document it is to look at the technical report and look at the amendments and see where those numbers differ.

Q. All right. Let me show you the -- Map 1. Map 1 is out of the Exxon book, so you have that reference. And I want to show you Exxon's Exhibit G-19, which is out of the bigger report, and it's the summary of potential reserves, including the workover and the waterflood. Let me hand that to you so that you have that in front of you.

All right, sir, here's the base map, and here's the spreadsheet.

A. Here's the way to answer your question. My

Exhibit 2-G is the letter of revisions -- It's the last part of Exhibit 6.

Q. All right, sir.

A. And at the bottom of that page it says something about reserves have been adjusted for five wells and lists them there, I believe.

Q. All right, I've got it.

A. Is that a way to answer your question?

Q. Yes, sir, I hope so.

When you look at the map and look at the Yates tracts that are in the -- Let's see if I get my sections right. In the northwest quarter of Section 30 there exist four tracts. Each of them has a number code.

And if you go down on the Exhibit G-19, you're going to find that code repeated, and you can read across. For example, if you look at what is identified as the EP7 well, it's within Tract 1111, and if you look on G-19 and find 1111, read across, it shows a workover potential for that well that gains it an additional 266,000 barrels of oil, attributed to workover. Do you see that?

A. Yes, sir.

Q. Has Yates independently evaluated the workover potential for their wells within this particular quarter section?

A. Yates -- How to say this. Yates thinks that the workover reserves estimated by Exxon are probably high, statement number one.

Statement number two, Exxon -- no, Yates, I work for Yates. Yates has recompleted a well -- I think it is EP7 -- and the result of that work is a well that is not going to make 266.6 thousand barrels of oil.

Q. That EP7 has been a producing well. Do you know what it's cum'd?

A. It has been a producing well. It has been a producing well in the Bone Springs Pool for a long time, and it was recompleted to the Delaware within the last 18 months or so. We could look on the Exxon exhibit and see, but it has cum'd --

Q. If you look at their Exhibit 22, they attribute approximately 2000 barrels of oil, it appears, if I've read this display correctly.

Do you have that display?

A. My recollection is, it had cum'd under 10,000 barrels, but it has cum'd -- It is far short of being on its way to 266,000 barrels.

Q. Okay. Do you know how they got these calculations for the workover potentials on your wells?

A. They explained it to me one time, but for you to expect me to explain their method to you now, it's not going to happen right, so --

Q. Have you independently verified the workover potential of your wells, or simply accepted what they gave you as a number?

A. Well, you can look back through these letters.

This is from my memory, but if you look at my letter of November 25th, 1992, that talks about their technical report, it says Yates is concerned that the workover reserves are too high, but since they benefit Yates by being too high we don't care if you change them or not.

Q. Okay, and so they weren't changed.

A. And they weren't changed.

Q. Look down for me on the tract that's 1311 now, which is the south offset to 1111. The workover potential in the Upper Cherry is another 213,000 barrels of oil. Do you see that?

A. Are you talking about 1311?

Q. Yes, sir.

A. Okay.

Q. They're going to give you another 213,000?

A. I see -- I see those numbers, yes.

Q. Okay, and when you read down and look at the next one, 1313, which is in the southeast of the northwest of 30, they're going to give you another 141,000?

A. Yeah, and those wells may actually have it, would be my off-the-cuff opinion, but --

Q. Those workover values, then, go into the primary reserve component --

A. No.

Q. -- for which you receive credit, do they not?

A. No, they go into the waterflood component.

Q. All right. So tell me how that is factored into the waterflood component.

A. What we have been calling waterflood reserves is what the technical report -- and by "we" I think I mean the whole hearing here today.

What we have been calling waterflood reserves are what the technical report calls waterflood reserves plus workover reserves.

Q. All right. So when I look at the spreadsheet that's attached to the unit agreement and I find it broken off into three columns, primary, waterflood and tertiary --

A. Yeah, and if you go to G-19, there are four columns and they match. If you add a workover and waterflood on G-19, you get waterflood on the one you're looking at there.

Q. That's what I was asking. I wanted to know where to put the workover reserves. They go into the waterflood column?

A. The workover reserves go into the waterflood column.

Q. All right. And so we'll -- We can look at the tracts and see where the workover reserves were added to the values of those tracts that had that potential, and they will appear in the calculation for the waterflood?

A. That's correct.

Q. All right. When we look down at the Premier tract, Exxon's concluded there's no workover potential for that well, and so no workover potential is added to the waterflood reserves for Tract 6.

The sum total of the calculation is -- In fact, there is no positive benefit for Tract 6 for waterflood?

A. You add zero and zero, and you get zero.

MR. KELLAHIN: That's all I need. Thank you.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Carr, any redirect?

MR. CARR: No, sir.

EXAMINER STOGNER: I have nothing of Dr. Boneau at this time. You may be excused.

Mr. Kellahin, let's take a ten-minute recess at this time, and we'll discuss how we want to proceed with this.

(Thereupon, a recess was taken at 4:49 p.m.)

(The following proceedings had at 4:58 p.m.)

EXAMINER STOGNER: Your attention, please. Let's convene for today until 8:15 in the morning, which we will proceed at that time with Mr. Kellahin's direct presentation.

Have a good night, see you at 8:15 in the morning.

(Evening recess taken at 4:58 p.m.)

* * *

that portion of these proceedings so designated

I do hereby certify that the foregoing is a complete record of ~~the proceedings~~ in the Examiner hearing of Case Nos. 11297/11298 heard by me on 29 June 1995.

, 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, Volume I, 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 8th, 1995.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998