STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:	CASE NOS. 11,297 11,298 (Consolidated)
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	ORIGINAL
APPLICATION OF EXXON CORPORATION FOR STATUTORY UNITIZATION, EDDY COUNTY, NEW MEXICO	

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

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

Volume II
December 15th, 1995
Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on Friday December 15th, 1995 (Volume II), at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X (Volume II)

December 15th, 1995
Commission Hearing
CASE NOS. 11,297, 11,298 (Consolidated)

(Continued...)

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E X H I B I T S (Volume II)

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* * *

WHEREUPON, the following proceedings were had at 8:33 a.m.:

CHAIRMAN LEMAY: Good morning. We're still the Oil Conservation Commission. This is still the case that we started yesterday, so we will continue on the Avalon-Delaware.

And let's see, you're sitting there, Mr. Bruce. Are you though?

MR. BRUCE: I'm through with my --

MR. KELLAHIN: He's welcome to stay right there, Mr. Chairman.

CHAIRMAN LEMAY: Okay. Well, I didn't know -- We've got our seating positions, so we'll go from there.

I assume that Yates is through also and that -- I don't see Mr. Carr, but --

MR. KELLAHIN: Mr. Carr went to the dentist this morning, and he's a little cranky. If you'll give me just a minute off the record here, I think he's standing in the hall trying to catch his breath.

CHAIRMAN LEMAY: All right.

(Off the record)

MR. CARR: I have finished my direct presentation.

(Off the record)

CHAIRMAN LEMAY: With that, we will begin with the presentation by Mr. Kellahin.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman. I'd like to call Ken Jones as my first witness.

KENNETH C. JONES,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Jones, would you please state your name and where you reside?

A. My name is Ken Jones, and I live in Dallas, Texas.

Q. Mr. Jones, what is your involvement with the company that's described as the opponent to the Yates-Exxon proposal here? We're calling it Premier Oil and Gas, Inc. What's your involvement with that company?

A. I'm the owner and operator of Premier Oil and Gas, along with my mother, Rosalie Jones.

Q. When your dad was alive, was he the primary individual responsible for the operations of the company?

A. Yes, he was.

Q. And when did your dad pass away?

A. He passed away in October of 1992.

Q. Since then, have you and your mom then continued operating under the name of Premier Oil and Gas, Inc.?

A. Yes, we have.

Q. Describe for me what your educational background is.

A. I have a chemistry degree from Baylor University and a doctor of dental surgery from Baylor in Dallas.

Q. You're in no way responsible for Mr. Carr's condition this morning, are you, sir?

A. No, I'm not. I hope it wasn't a root canal.

Q. How did you get into analyzing and reviewing the Exxon technical report, this August, 1992, publication that we spent yesterday talking about?

A. The August, 1992, publication is actually the second edition. There was a prior edition that I think was generated out of a November, 1991, meeting. We were not able to attend that meeting, because that was the beginning of my father's illness. That original report was sent to us in spring of 1992.

Q. So you got it in what? September or October of 1992?

A. So then we got the second edition, then, in -- I think it was in September of 1992.

Q. All right. As a practical oil and gas operator, what is your background and ability to understand on your own this information in that report?

A. I have no formal education per se, no petroleum engineering degree, but I have been around the oil and gas business for about 20 years with my father.

Q. In what particular way were you involved?

A. Just analyzing leases and discussing logs and possibilities of prospects within southeast New Mexico.

Q. When you got the Exxon technical report, the August, 1992, publication, did you spend time reviewing it and reading it?

A. Yes, I spent a lot of time.

Q. Describe for us the kind of things that you saw from your perspective and what reaction you had to those items in the report that you consider to be of importance to you.

A. I think -- Let me take a half a step back, and I think our first reaction was that we got a letter in September of 1991, and within that letter it stated that they wanted to put the unit together, that they -- they initially had a percentage.

And the percentage -- we didn't know where they came up with it. We didn't know if it was something that was actually what's going to be the formula for this unit. It turned out to be a pre-voting formula for the unit, and the percentage was like .2 of 1 percent for Premier.

Well, we called and screamed and fussed, and that was kind of our initial reaction to the report, was, we just got the property, we want to have the chance to develop it, we don't want to get caught up into a unit and not know really what's going on.

As time proceeded and we got the first report, I started looking at the reserves and was quite amazed at what CO_2 could do in the Delaware and felt like the report might be something promising for Premier, but we needed to look at it.

So I started going back in and studying how they did the report and how they came up with the volumetrics, how they made their picks, how the engineering went -- and I still don't have a true handle on that, and that's why I guess I have a consultant now for that -- then the economics behind it, of course, being the operator.

Q. What if any effect did receiving this concept from Exxon of a CO_2 project have upon your plans for activity on the Premier tract?

A. Well, it handcuffs you as an operator because you can't go out there and spend the money.

The initial report was such that -- Let me say, they had the meeting in November, 1991. We were not able to attend that meeting. Out of that meeting, they had planned on starting waterflooding by the second or third quarter of 1992. That was in their report.

There's no way that you can go out and spend the kind of money it takes to do a Delaware, be able to get rid of the water and realize any kind of value from that.

Q. Within the time frame they had told you, was their concept planned for the waterflood?

A. Exactly.

Q. All right. I don't want to spend any time on the details with regards to the report, but give us a sense of how the chronology of that report and your involvement, if any, in the process continued beyond September of 1992.

A. Okay. I want to go back to this pre-voting agreement that was issued and after we got a concept of what they were trying to do. This pre-voting agreement was basically a voting of the approval of this report. It didn't really have anything to do with what was going to be the actual formula. Exxon was not releasing the formula to anybody at that time.

We had a concept -- Well, let me finish that just a little bit longer.

They wanted approval of the report, and then they were going to call a big meeting, and at that time they were going to release the formula. That meeting did not happen until April of 1994.

In between this time, I had numerous phone calls with -- at that time, the project manager was Larry Long for Exxon, and I was continually asking, Well, when is things going to happen? What are we waiting on?

And he would continuously say, Well, it's going to be a couple more months; we're still waiting for Yates' approval.

I did not really have Yates' side of the story on this, but Exxon was relating to me that Yates was the holdup. And I don't think Exxon really cared whether I approved the report or not, because .2 of 1 percent is not going to affect the agreement.

What they were waiting on was Yates, because you're looking at a 70 or 80 percent, plus the other 10 or 12 percent, and that, combined, would be enough to initiate things.

Q. When you looked at the values they were using from geologic parameters for your property, and particularly targeted at the FV3 well, were you satisfied with the values they were attributing to your tract?

A. No, in the Spring of 1993 -- As I was working through the report, I started with the Brushy Canyon. In about early 1993, I was finally getting to the Cherry Canyon part of the study, and at that time I found what I thought was a mis-pick in the FV3 in the base of the Cherry Canyon.

Q. Were you involved in any material way with the negotiations that finally resolved the debate between Exxon and Yates, that present us to this Commission today their proposed solution?

A. No, I was not. And how I can explain that is, we had the meeting in April of 1994, in which the formula was finally shown. Prior to that, the only explanation I got from Exxon was that it would be based heavily upon reserves.

Well, as the operator, I'm sitting here looking at this reserve report. And if you go to G-19 -- At that time G-24 wasn't really out. I was looking at G-19, and I had about 4.25 percent of the total reserves. And that's what I was looking at. I didn't feel like there was any way you could go back out and break primary, secondary and tertiary and effectively do the report.

And this brings up part of the problem between Exxon and Yates, because if you go back and look at the report, Exxon wanted to waterflood this for three years, and then they wanted to go immediately to CO_2. Yates was scared of the AFE going straight to CO_2, and I believe this came out in Dr. Boneau's testimony yesterday. And this is part of what they were arguing about.

Now, taking that and relating it back to G-19 and back to the economics, as an operator what they were saying was that -- and what has finally been derived, is that 75 percent of the total unit value was going to be captured in the first three years of this unit. In other words, the primary and the secondary was all going to be captured in the first three years. And we got a 60-year flood, and now all of a sudden the other 60-year only means 25 percent.

Anyway, back to what I felt like was -- I was looking at 4.25 percent, just prior to even knowing what was going on.

Now, at that April meeting I asked that there be another meeting to meet over this geological pick. That meeting happened in May of 1994. And at that meeting Exxon would not agree, and Yates did not agree either.

Q. After that meeting, what if anything did you do about communicating to Exxon or Yates your desires for inclusion or exclusion in the unit?

A. At that meeting -- After that meeting, I wrote a letter and said -- We asked to remove our tracts from consideration of the unit.

Q. Did you attend the June 17th, 1994, operators' working interest owner meeting?

A. No, there was no reason to go. We had removed the tracts.

Q. What was your understanding and belief of what occurred after you communicated to them in writing you wanted your tract excluded?

A. My understanding was that I would be left out. Mr. Mayhew told me at the April meeting that they would leave us out.

My fear was that -- After I wrote the letter and after the June 17th meeting, they sent me the minutes to that meeting. And I thought that was kind of unusual, and I felt in the back of my mind that potentially I was still going to be faced with statutory unitization.

Q. When did you become aware that Yates was urging the inclusion of your tract into the unit?

A. Because I still had that fear, I believe I initiated a call to Mr. Mayhew around August or September, and I asked -- because in the June meeting, they still wanted to get going by the fall of 1994. And I asked at that time, What's going on? Has the thing been done? Am I going to be left alone?

He asked, or he relayed to me that Yates did not want us out, that Yates was going to propose a single-phase formula, and that -- would I reconsider it?

Well, looking back at the minutes, Dr. Boneau presented some ideas of where he was going to use oil in place and some other more traditional values. And I said, Sure, show me the formula and maybe I'll reconsider what is happening.

It got even stranger back -- later on in the negotiations, at that time between Exxon and Yates. I was pretty much not in it. I asked to see some things. I did not put any input into it.

In February --

Q. -- of 1995?

A. -- of 1995, in February of 1995, they came back to me and they said, here's what the formula is; will you consider being in?

Q. And this is the 25-50-25 formula?

A. Exactly.

Q. All right. And what did you tell them?

A. I told them that I didn't feel like one percent was fair. And I reissued a letter stating I do not want to be included within the unit, and please leave us alone.

Q. Following that, then, it became apparent to you that Exxon and Yates were going to go forward with including your tract?

A. The hint to me that was going to -- In that second letter where I reinformed them that I do not want to be within the unit, I told them in, I believe, the second paragraph, something to the effect, if you're going to do statutory unitization you'd better not do it in August, because we were about to have another baby --

Q. All right --

A. -- and I said I cannot deal with that and this issue at the same time; you're going to get delayed.

And the reason I came to that conclusion was because in some of the letters between Exxon and Yates, they had tables with Premier acreage and without Premier acreage, and this final issue was with Premier acreage, which kind of smelled to me like we're going to statutory unitization.

Q. All right. At what point in this process did you seek consultants from the geologic field to analyze your values as attributed by Exxon in the report?

A. Well, that's come in stages. After the first Upper Cherry Canyon pick, I -- We have an engineering consultant in Artesia, Paul White, who I worked with a lot in showing him the pick and evaluating it, and we had a couple separate meetings without Yates and simply with Exxon about the pick and discussing it. Exxon would not change their mind at either of those two meetings. These were prior to the big meeting with Yates and Exxon.

Q. At what point did you --

A. Following --

Q. Yeah, go ahead.

A. Then, following the final issue that they were going to do statutory unitization, that's when I went and hired Gerald Harrington and Stu Hanson as geologists, and Paul White was still working with us on this case at that time.

Q. All right. When you hired Stu Hanson to make a geologic investigation of your property, did you recommend to him any conclusions or solutions or opinions that you wanted him to reach?

A. No, not initially, I did not.

Q. You asked him to make --

A. I asked him to draw his own conclusions because, once again, I'm not an expert in geology. I know enough to be dangerous. And I wanted his conclusions because I was fixing to have to spend a lot of money in going to court, and I wanted an expert's opinion on the pick, and I wanted it irrelevant of any conclusion that I had drawn.

Q. And Stu Hanson is here today to present your geologic position with regards to the technical case?

A. Yes, he is.

Q. All right. As part of your opposition to this case, have you also retained a consulting engineering firm in Austin, Texas, to assist you in evaluating your position and to examine the Exxon proposal and to make recommendations for solutions to the problems that they perceive?

A. Yes, I did, in October of 1995, I certainly did.

Q. And that individual representing you today for the engineering aspect of the case is Mr. Terry Payne?

A. Correct.

Q. Summarize for us in conclusion, Mr. Jones, what's your position and what are you asking the Commission to do for you?

A. We're asking the Commission to leave us out of the unit. And if they don't leave us out of the unit, we are asking them to please look at our engineering and our geology and draw some fair and reasonable conclusions from it and treat the Premiere acreage correctly.

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

CHAIRMAN LEMAY: Mr. Bruce?

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Jones, you admitted that after that June, 19- -- or after that May, 1994, working interest owners' meeting, you continued to get phone calls or make phone calls to Yates, right?

A. I made phone calls to Yates after discussing with Mr. Mayhew in August. It would have been in the fall that I had a couple of conversations with Mr. Boneau.

Q. Did Mr. Boneau ever call you directly?

A. I don't believe so.

Q. Did -- You mentioned also correspondence between Exxon and Yates from the fall of 1994. Did you receive that?

A. Yes, I did.

Q. So you -- Why would they send you that correspondence, and why would they make those phone calls if there was not a chance to leave Tract 6 in the unit?

A. I had already taken the tract out. I admit that. My fear was, still, that there would be statutory unitization. That's why I called Mr. Mayhew -- it would probably have been in August or September of 1994 -- and I said, Are you all through with this? Have you gone to Santa Fe and resolved the whole problem? Am I free, finally?

And at that time, that's when he asked me to please consider a single-phase formula that Dr. Boneau is going to propose.

Q. Did you tell Ron Mayhew of Exxon about a year ago that you would propose your own formula?

A. In December, I think my final conversation was, I said, Well, maybe I'll come up with my own idea and present it to you.

Q. But until Wednesday, no formula was ever proposed?

A. That was correct.

Q. Meaning Wednesday, the 13th of December, 1995?

A. That is correct.

Q. At this May, 1994, working interest owners' meeting, were there other working interest representatives besides Exxon and Yates?

A. At which meeting?

Q. The May, 1994, meeting to discuss geology.

A. Yes, from Patrick Petroleum. I'm sorry, I forget his name. Patrick, who is now Unit, had a representative there, yes. Yates was the only other interested party.

Q. And you mentioned you had at least -- What? Three, maybe four meetings with Exxon or other working interest owners to discuss your geologic interpretation?

A. Yes, I believe we had two with Exxon privately. Those would have been in 1993.

Q. What's the current status of the FV3 well?

A. It is no longer TA'd. In October of this year we went in and removed the plugs from it and put it on pumping status.

Q. What was the result?

A. We had about eight or nine days of zero production, and then we had about six days, and it made about -- a rough guess, if there was 42 barrels in the tank, probably 15 or 20 barrels in the heater, so say roughly 60 barrels, and I don't remember how much water.

Q. Roughly 300 barrels a day?

A. I would say roughly 300 barrels a day.

Q. Which zones were tested?

A. Well, you're going to open up another subject, but what -- There were two plugs in this well that Gulf -- Gulf tested two zones.

They tested the zone that currently Exxon says is below the Upper Brushy Canyon. They acidized, frac'd it, they flowed it back to one day, they swabbed it for one day, they received about 50 percent of their frac treatment back. They started showing a taint of oil at the end of the second day.

They immediately put a bridge plug over it and went back up the hole to the Cherry Canyon, acidized and perforated that.

So what has happened when I removed both bridge plugs was that both of those zones were open.

Q. Okay. So what you're telling me, you got somewhere between -- like seven -- maybe seven barrels a day of water and 300 barrels a day of -- I mean seven barrels of oil and 300 barrels of water per day?

A. It was too difficult to say, because the oil was flowing up the back side of the well. There was no way to really account for it. We had some production problem equipments out there.

Q. So you decided to discontinue any further work on the well?

A. No, Exxon decided to discontinue any further work on the well.

Q. What do you mean by that?

A. Exxon is the one that shut the well down. We were not -- I'm going to have to say, I'm learning every day, but the unit was within order. We did not realize that when the order was written in September, that Exxon became immediate operators. We felt like there would probably be some kind of an effective date. We did not know what that effective date was. We still felt like we had a window of opportunity to potentially go out there and just show that there was some primary production within the well.

Q. Isn't it true that Exxon offered to allow you to continue testing your well?

A. Yes, they did, but I think if you go back and look at the economics behind that, it's extremely poor.

Q. Okay. So --

A. What they're saying is --

Q. -- Exxon --

A. -- they're going to get one

Q. -- to take the water --

MR. KELLAHIN: May the witness finish his answer to the question before another question is asked?

THE WITNESS: Exxon said, yes, we've worked out an arrangement where we could have disposed of the water. But the unit -- I was basically going to get one percent of the oil, because it was within the unit already as the order was written.

Q. (By Mr. Bruce) But if you had to dispose of the water yourself, it was uneconomic for you to continue producing that well?

A. It was too early from the test to tell.

Q. Well, why didn't you continue producing the well?

A. Because I was only going to get one percent of the oil. You still have other operational costs besides water.

Q. Would you have continued producing that well if it was producing 300 barrels of water per day, six or seven barrels of oil per day, and you got all the production?

A. Not if it was making six or seven barrels a day. But once again, the well was starting to come on. We don't know -- I don't -- I think if you're dreaming it was going to get beyond 20 or 25 barrels a day, that would be stretching it.

MR. BRUCE: Mr. Chairman, the keeper of the exhibits is missing. I'd like to enter into evidence -- I'll hand this to Mr. Jones and have him identify it. I will provide copies to the Commission and --

MR. KELLAHIN: Is this in that exhibit stack?

MR. BRUCE: No, no.

MR. KELLAHIN: This is outside that?

Q. (By Mr. Bruce) Could you identify that? It's a package of three letters, Mr. Jones. Could you identify what those are?

A. This is correspondence between Exxon and myself, and we were trying to become -- we were trying to come to some kind of arrangement such that the operation of the well would be within the guidelines of Exxon's OSHA rules, and also a way of disposing of the water such that we could continue producing the well.

Q. Did you ever respond in writing to these letters?

A. I never -- The last agreement letter, which is probably the most important letter, I never did sign, no. There was not -- I never did come to that agreement. I still felt like it was important to separate us from Exxon and not show our inclusion with Exxon within this unit.

I also want to add one other thing. The first time we actually knew the effective date was in a letter from Joe Thomas, dated October 18th, telling us that the effective date of the unit was October 1st.

We still felt like that window of opportunity was there, and we still felt like we were still operators of the well. The OCD in Artesia approved that, they approved --

MR. BRUCE: Mr. Chairman, we're not here to suggest that Mr. Jones was doing anything illegal. We don't have any problem with that. We just merely -- The effective date of the unit doesn't play into this. It's just that -- We just want to show what the correspondence was between Exxon and Premier.

MR. KELLAHIN: Mr. Chairman, I think the topic is irrelevant. It's a failed effort by Premier and Exxon to come to some agreement about further activity on the FV3 well. I'm happy if the Commission wants to spend its time on this topic. I don't see how it aids you in the process.

MR. BRUCE: I'm done with my questioning, Mr. Chairman, but it's not irrelevant.

THE WITNESS: These perfs --

MR. BRUCE: This part -- Part of this case has to do with the geology and the productive capabilities of the FV3 well, and we think this is directly on point.

THE WITNESS: But these lower perfs are excluded out of this unit anyway, the lower perfs that I'm talking about.

CHAIRMAN LEMAY: Well, is this the only time it's going to be covered, or is engineering testimony --

MR. BRUCE: I'm not --

CHAIRMAN LEMAY: -- going to go into this testing?

THE WITNESS: No, we're not covering it.

CHAIRMAN LEMAY: Well, I think it's significant in the sense that you did run some tests on this well that would be part of the unit, and the issue came up before, whether this well was economic or uneconomic.

So from that point of view, I think it's relevant testimony.

MR. KELLAHIN: All right, sir.

MR. BRUCE: And I have nothing further of this witness.

CHAIRMAN LEMAY: Okay.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Point of clarification, then. Ken, when we're looking at this test, there is nothing in this test that's attributable to the Upper Cherry Canyon interval for which you are seeking the additional inclusion of this 82 feet of net pay that Exxon is intending to exclude?

A. Correct.

Q. All right. This test relates to zones in this wellbore outside of that issue?

A. Correct.

MR. KELLAHIN: All right. No further questions.

MR. BRUCE: I didn't quite understand, but the entire Delaware interval is unitized, Mr. Chairman.

CHAIRMAN LEMAY: Yes, we understand.

You're through with cross?

MR. KELLAHIN: Yes, sir.

CHAIRMAN LEMAY: Mr. Carr?

EXAMINATION

BY MR. CARR:

Q. Dr. Jones, when did Premier actually acquire the acreage that is the subject of this hearing?

A. In July, 1990. July 1st, 1990, was the closing date with Chevron.

Q. And it was acquired from whom?

A. Chevron.

Q. At the time it was acquired, was the FV3 well in existence at that time?

A. Yeah, it was TA'd. It was encased, yes.

Q. From that time, when you acquired the property, through the effective date of this unit, did Premier do anything to attempt to return this acreage to actual production?

A. We did some things for the FV1 and FV2, but we did not do anything for the FV3, no.

Q. Was there any test on the FV3 at all?

A. No, because there was some -- There was still land problems. We did not -- The lease purchase from Chevron was the FV lease.

It does not include the whole section. There's 120 acres on the northern half that was owned by another company in Houston at that time.

There was -- In the Delaware there was a communitization rule, and Amoco originally was the owner of that little 120-acre lease, and one-eighth of the ownership was with Amoco and seven-eighths with Chevron. So there was a question of whether we needed to deal with this other company or not. And we were going through negotiations, trying to buy them out at that time.

Q. From the time you acquired the property until the effective date of the unit, nothing was done to test or otherwise return the FV3 to production; is that right?

A. Correct. But we were handcuffed as of --

Q. And you went in --

A. But we were handcuffed as of the summer of 1991. I mean, that's when -- May of 1991 is when the first meeting was.

Q. And so during that entire period of time, knowing that you had questions about whether or not the tract would be and what the formula may be, there was nothing done to this well to acquire any hard information on what it might be able to produce?

A. No, there wasn't any reason to do. There wasn't any reason to.

Q. And so when you went into these hearings, having had no reason to try and establish any -- or acquire any data on the well, you went in with only the information that you had, and that was, you thought you might be able to return it to production, correct?

A. Correct.

Q. And you tried to do that after the unit was established; isn't that right?

A. Yes, that's correct.

Q. And you've produced about 300 barrels of water a day; is that correct?

A. Correct, and the oil was coming up and the gas was coming up and -- The test has been abandoned, so nobody knows. It's irrelevant.

Q. As the operator of that well, do you have any opinion as to what would be the source of the water that was being produced in that well? Do you know if it was Delaware or not?

A. Well, you still -- we still had half of the frac recovered down in that lower zone, so a lot of the water was coming from that.

Q. Do you know if the other -- rest of the water was coming from the Delaware or some other zone?

A. We did not go back in and try and isolate the perfs and find out where the water was coming from.

When we went in and removed the plugs, there was not a whole lot of pressure above the Upper Cherry Canyon. When we removed the plugs covering this frac job, the well started flowing back up the 5-1/2-inch casing --

Q. My question is, do you --

A. -- so that the pressure is coming from there.

Q. -- do you know whether or not this well needs to be repaired to isolate the water?

A. Well, the test wasn't finished. I mean, there's no way to -- You can't draw that conclusion until the test was finished.

Q. So you don't know?

A. No, I don't know. Certainly don't know.

Q. Now, when you got the technical report --

A. Uh-huh.

Q. -- you were interested in the potential for a CO_2 flood in this area; is that not correct?

A. I thought the reserves were staggering.

Q. In terms of the implementation of a CO_2 flood, isn't it, in your opinion, appropriate that someone like Exxon ought to take the lead in implementing that kind of a program?

A. Well, there -- there's no doubt about that.

Q. You're not quarreling with the fact that Exxon has had the technical and financial resources to do it?

A. No, I don't -- there's no --

Q. You're not suggesting that Premier should do that instead of Exxon?

A. No, I'm not -- Not initiating the whole flood. I'm not trying to become the operator of the entire flood, no.

MR. CARR: That's all I have.

CHAIRMAN LEMAY: Mr. Bruce?

MR. BRUCE: Follow-up on something Mr. Carr asked.

FURTHER EXAMINATION

BY MR. BRUCE:

Q. Didn't Paul White, your former engineer, advise you to drill back in 1993 to prove up your acreage?

A. Paul White felt like it was important to show production out there. Paul White does not make the calls on the economics as the operator.

MR. BRUCE: Thank you.

THE WITNESS: He also -- I mean, if you want to put in --

MR. KELLAHIN: You've answered, Ken. That's fine.

THE WITNESS: Okay.

MR. KELLAHIN: One point of clarification, Mr. Chairman.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Carr has asked about the water. Did you have any technical data available to you to analyze by which you could come as a practical oil and gas operator to any conclusion about what's happening with that water in the FV3 well?

A. No.

Q. Was there any information indicating that that water might be channeling from somewhere?

A. There is information from Gulf sources that shows that the water may be channeling, but I felt like most of the water in the tests that we did was coming from those zones below the Upper Brushy Canyon.

Q. What is the source of the information from Gulf that indicates that some of this water might be channeling from some other source?

A. There's a temperature log that they ran after they acidized the Upper Cherry Canyon that shows that it went out of zone.

MR. KELLAHIN: Nothing further, Mr. Chairman.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Do you have other Delaware properties that would have aided you in your interpretation of the logs or the quality of the water or any background there?

A. No, we do not. I've looked at logs from other wells, but I don't own any of the properties.

Q. Okay. This first edition that you spoke of for the Exxon report, did it have the same unit boundaries as what's presented here?

A. The same unit boundaries -- There was a change in the vertical boundaries, because the first edition did not include the Lower Cherry Canyon at that time. But there's not any issue about that, so...

Q. Okay. Dr. Boneau yesterday said that during his negotiations with Exxon concerning their formula for -- that he had spoken to you several times, and specifically my question was whether the benefit that accrued to Premier was a side effect of their negotiations or whether or not you were involved in any of those discussions?

A. I was not involved in the discussion. I believe -- I made two phone calls to Dr. Boneau. One of the phone calls was in reference to a letter that was sent to Mr. Mayhew.

In that letter -- Yates was willing to pay for more of the capital costs than what they were going to receive in working interest. Premier, in their formula, was going to have to pay four times the capital costs than what they were going to receive in working interests.

And they were still in a two-phase formula, and the negotiations were not going anywhere, and I was basically calling, saying, What are you all doing? Why are you willing to pay for more of the capital costs than what you're going to receive in the working interest owner?

And Mr. Boneau's response was that Mr. Peyton Yates felt like it was fair. And I just left it at that. I was kind of flabbergasted.

Q. But you were aware that Premier would benefit from the negotiations at that time?

A. I knew that they were still corresponding about me. I knew that in these letters that they were coming up with tables with Premier acreage and without Premier acreage. I knew about that. But I had no input to what the formula was.

Q. Your first desire is to be left out of the unit; the test indicated that the economics of primary production were questionable; it's not a candidate for waterflood on its own. What would you do with this well if it were not?

A. I think you'll see in the engineering and the geology that there are other zones within the well, that there's potential behind.

There is, for instance, potential within the FV2. The FV2, which is further into our section, had a blowout within what I would describe the Lower Brushy Canyon. It is not even -- We have not even tested that well yet. We have not had the -- there's -- It's been a handcuff situation from the start.

Q. So you're saying if it's not included in the unit, you would test other zones and try primary production in other --

A. Certainly.

Q. -- zones within that well?

And if they were successful, then those reserves that may be there would be left in the ground?

A. Certainly. We have two very good locations directly north of the FV3 too.

Q. That you would intend to drill?

A. Yes.

COMMISSIONER BAILEY: That's all.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Mr. Jones, what prompted you to test the well here recently?

A. I felt like from -- Well, one aspect of it was, I felt like I could show the Commission that the number or the formula is skewed.

I felt like if the well would have came back and was making 25 barrels a day, for instance, out of this zone, regardless of what the water was, that I could start plugging in some numbers into their formula and show how it really skews the whole report, because they were weighting so heavily on primary, they were weighting so heavily on secondary, when the whole concept of this flood is to do a tertiary flood in the future.

Q. But you had time to do this earlier. It sounds like the test was a bust.

A. The test was inconclusive. I mean, I'm not -- I wouldn't sit up here and tell you it was going to be anything great, but it was inconclusive, I felt.

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

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Dr. Jones, did you go in there and try and isolate what I assume you think is additional pay, if you have a different correlation, with packers or anything, to try and prove this was oil-productive?

A. No, sir, I was still -- In this test, like I've testified, there was seven or eight days of absolute total water.

When we were pumping the well through the next six days, the well was still pumping water, but it was flowing oil back up the casing, and the gas pressure was continuing to increase, and the oil was coming up. It was not coming up dramatically, but I would say over the six days it probably averaged ten barrels a day.

So at that time is when Mr. Mayhew called me and said we were in violation. He said, We've got some problems, maybe we can work with you on it, but there's some problems out there with OSHA standards that you need to address.

So I shut the well down. I needed to wait for Mr. Kellahin to come back from vacation, I needed to discuss many different things with him.

Q. When did you think this well had additional potential? You mentioned a couple things here that you thought the well might have additional oil somewhere, Lower Brushy Canyon, this correlation that would, as I understand it, give you more pay than Exxon gave you credit for. When did that realization come to you?

A. There's an unmanned mud log from this well, and there are notes on the original log that we obtained from Chevron in the transfer of ownership, and from those notes we were able to piece together some places that have some potential.

The Lower Brushy Canyon, at the very -- just above the Bone Springs sand, there are some sands that they show strong cuts out of, gas kicks out of. There are -- In the Lower Cherry Canyon, they reported oil on the bits. There are some zones, in the Middle Cherry Canyon that has got gas shows through.

So there is some potential. We don't know what it is, we don't have any realization.

But what's going to happen is, the whole reservoir is going to be unitized, but we're only going to get credit out of these two pieces. So what the focus of the report is, is just the two pieces in the Delaware. That doesn't mean that the well does not have other paying zones within it, and nobody really knows yet, because nobody's -- we have not tested.

Q. Well, did you at all propose to Exxon that you might drill another well to test these zones, core them, somehow evaluate them, somehow realize this potential so it's not potential, so it would be -- I would think that for all unit operators, that realization, not just speculation, based on some evidence, realization of true additional potential would be highly valuable to you and everyone else?

A. I think so. I agree with what you're saying. Understand, I was looking at, first of all, the economics.

And I was, second of all -- I kept in touch with Exxon quite well about what was going on in terms of the negotiations in the approval of this, not in what the formula was. And the only piece of information that Exxon would tell me about what the formula was going to be was that it was going to be heavily related upon reserves. And I was looking at four percent of the reserves off G-19 and saying, Well, why not just sit back and spend money on other projects and realize --

Q. Do you realize how speculative CO_2 flooding is and that we don't have a lot of history with it?

A. I realize now. I didn't know, sir. I didn't -- I was taking Exxon at their word. If they were going to say it was going to make 50 million barrels, I felt like they had the technology that they were going to re- -- If that's the whole case of this report -- I mean, I wasn't going to disagree with it. I didn't have any formal training to disagree with it, and I'm not sure that there's too many people that do besides Exxon.

So if it was going to make 50 million barrels, then -- You know, the project could make 30 million, it could make 70 million. I don't think anybody here can tell you.

Q. It could make zero?

A. That's exactly right, I realize that now.

Q. Did you at any time enter into negotiations wanting to sell your property, or was that something you just never wanted to do?

A. Exxon came up and they asked about it one time, and they asked about selling the property, and they made a -- what I would say remarkably low offer for it, and I was not interested in it.

I still felt like I wanted -- I owned the whole section, I didn't want to split the Delaware up, I wanted to be able to maintain that as a whole.

CHAIRMAN LEMAY: Here's my -- I bring that up, it hasn't been mentioned, and many times that's typical in waterflood tertiary operations where large capital expenditures are necessary, many times the operator buys out the smaller interests so they're not part of the project.

That's the only question I had.

Additional -- ? Yes, Mr. Bruce?

FURTHER EXAMINATION

BY MR. BRUCE:

Q. Dr. Jones, you mentioned the FV2. That's outside the unit boundary, the FV2 well?

A. Yes, it is, and that draws the point that -- why I wanted to keep the Delaware as a whole.

Q. What is the producing zone in that well?

A. Currently it's in the Canyon.

Q. Oil well, gas well? Oil well or gas well?

A. It's a gas.

Q. What is its current average monthly producing rate?

A. Oh, it's extremely low. Maybe 300, 200 MCF a month.

Q. And then one other well was mentioned yesterday, the FV1, which is, I think, on Tract 6; is that correct?

A. Correct.

Q. And what's the status of that well?

A. That well is making some gas out of the first Bone Springs sand. This lease was purchased because of the Bone Springs and the Delaware, and we're currently working up in the Bone Springs right now. We still have another pay for that well.

Q. How much is it producing, on a monthly basis?

A. It would probably be still in the same range. After -- We spent probably $120,000 on that well, and we probably have only captured 40 million cubic feet of gas. I don't -- To be honest with you, I can't tell you the exact number, but it's very low right now. It's probably something on the order --

Q. -- producing --

A. -- probably something on the order of the FV2, correct.

Q. Have you filed production reports on the FV1?

A. Oh, yeah, there are C-104s at the OCD office at Artesia all the time.

MR. BRUCE: That's all I have, Mr. Chairman.

CHAIRMAN LEMAY: Any other questions of the witness?

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: If not, thank you. He may be excused.

MR. KELLAHIN: Mr. Chairman, we'll call Stu Hanson at this time.

STUART D. HANSON,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Hanson, would you please state your name and occupation, sir?

A. My name is Stuart Hanson. I'm a consulting geologist.

Q. Where do you reside, sir?

A. Roswell, New Mexico.

Q. On past occasions have you testified and qualified as an expert in the field of petroleum geology before the Oil Conservation Division?

A. Yes, sir.

Q. As part of your professional employment as a geologist, have you in the past had occasion to examine exploration and production geology with regards to the Delaware Mountain group in southeastern New Mexico?

A. Yes, sir.

Q. What has been that experience?

A. I started with Union Oil of California in 1972, Esperanza field, worked for Hannigan Petroleum. We never drilled -- Yes, we did drill some Delaware, excuse me, a couple of them. But we did extensive exploration work with the Hannigans for Delaware, got interested in it.

In 1983, I was one of the founders of Siete Oil and Gas, and we found quite a bit of Delaware oil.

Q. There's a hum in the fan in the ceiling, Mr. Hanson, and you're soft-spoken. That microphone will not amplify your voice, it's for the court reporter's use. If you need some water, I've brought my water bottle --

A. I'll speak up as --

Q. -- there for you. Try to speak up if you can.

A. I'll speak up as loudly as I can.

CHAIRMAN LEMAY: Avalon-Delaware water?

MR. KELLAHIN: No, sir, this is not the Avalon, this is not Avalon injection water.

THE WITNESS: I'll speak up as loudly as I can.

Q. (By Mr. Kellahin) All right, sir.

Summarize for us, Mr. Hanson, what has been your involvement with regards to the subject matter of the hearing before the Commission today.

A. I was hired by Mr. Jones to independently look specifically at the correlations in the area of his Tract 6, as far as the northwest corner of the Avalon-Delaware field.

Q. Summarize for us the kinds of tools and geologic information that you drew upon to make that independent evaluation of his property.

A. I used well logs, drilling reports, such maps as he had available, including Exxon's technical report and maps, some maps that were generated by Jerry Harrington and myself, and then past experience.

Q. When we look at your geologic presentation this morning, some of these displays have Mr. Harrington's name on the bottom of them, but they represent your work product as well as his?

A. Yes, sir, they do.

Q. As a result of that information, were you able to reach conclusions and recommendations to make to Mr. Jones?

A. Yes, sir.

Q. As part of that process, did you attend and were you involved in the Examiner hearing of this case?

A. Yes, sir.

Q. And you were here yesterday to hear the geologic presentation made by Exxon?

A. Yes, sir.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Hanson as an expert petroleum geologist.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) I'd like you to go back and, before we look at the exhibits themselves, give us a general description of the Delaware reservoirs with regards to their deposition, their environment, so that we have a geologic setting by which to understand your technical work.

A. Yes, sir. The Delaware Mountain Group is broken up into three units: Bell Canyon, Cherry Canyon and Brushy Canyon. These are large correlational units and involve a number of different depositional environments, probably within each of them. There are certain eustatic sea-level changes associated with them.

Specifically here, we are going to be addressing a small part of the Cherry Canyon and a rather unusual part of the reservoir in that we're approaching the edge of Delaware deposition along the northwest shelf.

What's unique about these particular depositional environments we'll be looking at is that they are fairly high-energy submarine canyon fan deposits and involve two kinds of deposition and quite a number of controls on how that deposition is -- takes place.

Q. All right. Let's commence, then, with your presentation. Let me take a moment and hand out extra copies of the displays, and then we'll go first of all to the copies that we've mounted on the display boards, and that's how we'll proceed.

A. Yes, sir.

Q. It won't be necessary for you to unfold these maps. We're going to bring large copies forward, so you can --

A. Okay.

Q. Mr. Hanson, let's start with what I've marked as Premier Exhibit Number 2. It's the B-B' cross-section.

Before we have that discussion, let's have you simply identify the two wells that are on the B-B' cross-section.

A. B-B' cross-section is just a short correlation section running from Premier's FV State Number 3 to the Yates petroleum WM4, which is immediately east of the FV3.

Q. When you have reviewed the Exxon geologic information in the cross-sections, did you find a direct correlation in any of their cross-sections with regards to these two wells?

A. Yes, sir.

Q. You found a cross-section in their book where they put the --

A. Oh, no, no, not where they had them juxtaposed as they are in this one. I'm sorry, I misunderstood your question.

I found a cross-section that contained both wells, but not juxtaposed on the same cross-section.

Q. Describe for us what you have done with this cross-section.

A. I was presented this cross-section without correlation in it --

Q. Okay.

A. -- so I could come to my own conclusions. And I also had Exxon's correlations at that time, which I posted on the WM4, and then seeing -- I had already looked at Exxon's correlations and some of their other cross-sections, and at least as far as the macro-correlations, the standard regional correlations, I had no significant disagreement with it.

So I brought those correlations in from one of their cross-sections -- Number 3, I think, I'm not positive of that -- to the WM4, and then independently ran my correlations over to the FV3 from picks that they had on the WM4.

Q. Take us through the analysis, then, and describe for us what you've done and what you've concluded.

A. Okay. Well, the detailed correlation, first off, take the simple ones, base of the Goat Seep, Cherry Canyon marker on this one, nobody's got a problem with those.

I didn't have any problem with the Exxon -- You know, as far as the rest of the picks, as long as everybody's talking the same language you're always going to have a little bit of difference as to what horizons people want to look at.

So taking Exxon's correlations from the WM4, I ran them back to my opinion of what was the correlation in the FV3. And in order to get there I used the pattern analysis of the log appearance from well to well.

Q. Describe for us, then, the significance of the color-coding on each of the logs. What does that mean?

A. Well, this is just -- What that is, is just kind of an idea to give you some of the processes used to try to get from one to the other. You work from the bottom to the top and from the top to the bottom. You work from the known to the unknown, and you try to interpolate in between. You look for as many similarities as you can and try to correlate those similarities.

But you also need to be paying attention to what the nature of those similarities are and what might happen to either make separate events look the same or what might make the same event look different or what else might have happened during the deposition that could change the correlation or the appearance of the correlation.

Q. When you look at the Upper Cherry Canyon formation, do you have an agreement or a disagreement with Exxon with regards to the thickness attributed to the FV3 well with regards to that reservoir?

A. Yes, sir, I do. I've got a small difference at the Upper Cherry Canyon pick and a rather significant difference at the Upper Cherry Canyon base.

Q. So you do in fact have a disagreement?

A. Yes, sir.

Q. Show us what you have concluded.

A. Well, the dashed lines in red are Exxon's correlations between the two wells, as established from two different cross-sections that they had in the book.

The solid black lines are the correlations that I came up with, which, as it ended up, were not significantly different -- as a matter of fact, were insignificantly different from either Jerry Kenyon's or both Paul White's -- Jerry Harrington.

The main difference was in this sand package right down here, and it comprises a gross interval of 84 feet of the reservoir, and it nets out at 82 feet and

4.9-percent porosity or something like that.

There was a small difference up here at the top of a few feet. But that's -- the main -- As far as the mapping unit, from the Upper Cherry Canyon middle to the Upper Cherry Canyon base, there's a significant difference of 84 feet.

Q. All right, let's find the footages. When we look at the Upper Cherry Canyon, what Mr. Cantrell identified as the Downlap marker, on your analysis you find that to be at 2546?

A. Yes, sir.

Q. And he finds it to be lower, at 2589?

A. Yes, sir.

Q. When you look at the base of the Upper Cherry Canyon formation, am I correct in understanding that your display shows you conclude it to be at 2852?

A. Yes, sir.

Q. And that under Mr. Cantrell's correlation he finds that to be at 2768?

A. Let's see -- -58, sir, 2758.

Q. 2758, all right. The difference, then, is, you attributed a net pay for that wellbore of an additional 82 feet?

A. Yes, sir.

Q. Did you use the same cutoff values that Mr.

Cantrell did to get from gross to net?

A. Yes, sir.

Q. So there's no difference in that methodology?

A. No, sir.

Q. Describe for us why, in your opinion, you think Mr. Cantrell's wrong in determining the net footage with regards to the FV3 well.

A. Okay. In order to do this, now, I have to go regional and then back to local --

Q. All right, let's do that.

A. -- because -- In large part I have very little disagreement with Exxon on this. Their idea of going from regional framework to set up a local framework, there's absolutely nothing wrong with that. That's what you have to do.

Q. And that's in fact what you have done?

A. Exactly. I have had -- In the past, I've had Delaware cross-sections going all across the entire basement for the sole purpose of knowing where I was when I got someplace.

But anyway, in this particular area --

Q. Just a minute. No one's going to be able to see you there, Stu. Let me turn that around.

CHAIRMAN LEMAY: Some of you want to come around here, feel free to, so you can see what he's drawing.

We're informal, so just come join us.

Q. (By Mr. Kellahin) All right, please continue, Stu.

A. Okay. A lot of this is somewhat repetitious from what they've already presented, and it's only because we'll need the framework.

Okay, we've got the northwest shelf coming around here, and you've got that Avalon associated with it approximately here. And then you've got Parkway associated approximately there, East Shugart. The scale is not too good but...

These submarine canyon fans are a source of the sediment, from the northwest or north-northwest or something like that. And these things may be braided or whatever, doesn't make any difference.

As far as the source, generally accepted to be something on the order of -- We don't really care, because all we care about is that a source rock provided chemically and physically weathered sediments to drainages that were intersecting this shelf edge at these points, and that's what we really want to address.

What happens to -- Okay, the kinds of sediment we're dealing with, generally pillow clastics, we've got particulate carbonates, particulate clays and particulate silicates ranging from very small silt sizes up through fairly coarse sands.

What happens to those things is, they are transported subject to various environmental conditions. Usually rain will transport it down drainages into these intersections with the shelf.

What takes place at that point is fairly unique to this type of Delaware deposition. This is not the same kind of deposition that you're going to see further on in the Basin, associated with any of the other members of the Delaware Mountain Group. These are higher-energy deposits.

And because of those higher-energy and intermittent-energy -- intermittent levels of energy transport and generally higher energy regimes of that transport when it is taking place, you get a difference in the nature of these deposits. They're called submarine canyon dam assemblages. Some people have some other names for them. What it boils down to is that they are the result of density currents. There's different names for those. Some people call them turbidites. I think that kind of clouds the issue, and I didn't mean that as a pun.

The problem with turbidites is, people expect to see either a full or a partial drill sequence in a turbidite. And I'm going to make another little drawing here that's going to explain why that isn't exactly necessary.

This is going to be a schematic graph, and it has to do with what happens to sediments transported this way. And this axis down here, the X axis, is going to be grain size/density, which are -- you can see are related to density lithology. And this is going to be energy, transport energy, increasing this way, increasing this way.

This energy can mostly be looked at as a function of the speed of the liquid medium. Density currents are -- oh, probably mostly in the 85- to 95-percent solid range, with a small amount of fluids. They are called bottomholes sometimes because they travel very near the bottom of the transport drainages.

They can be extremely erosive, depending on the nature -- depending on how fast they're moving. That relationship is described by an exponential curve, something like that. It's actually steeper than that, because in the equation that component of the equation that brings in the speed uses the sixth power of the speed. It's the only actual equation that I know of that uses the sixth-power exponent. But all that means is that once you get to this point it brings change very, very rapidly.

There's another line on this thing that's associated with it. It's something like that, doesn't really -- This is completely schematic. What takes place in this area down here is deposition. What takes place in this area right here is a combination of -- is transport, excuse me. And -- Let me see, transport. And then up here we've got transport and erosion.

You can see from this, as you increase the energy, you start to move -- you start to transport larger size clastics. Once the energy increases for a given size clastic past a certain point, that bottomhole transport where the transport -- or the medium with the clastic in it actually begins to cut the surfaces that it is being carried upon, that it's abrading against.

That take place quite a bit in these submarine canyon fans. It takes place in the canyon it's feeding, the hill, and perhaps at this point we should look at the side view of the hill. This is going to be kind of vertically exaggerated, but you're looking at a gradient.

Now, drainage coming in here, it hits this point, the gradient changes downward. Well, as the gradient changes downward, gravity upon it increases and, you know, water flows faster. So the energy increases.

You get here, the energy decreases because the gradient decreases. What happens is, you've got cut, more cut. You get down here, drop down below this level, starting to cause it -- start depositing some sands.

This is really simplistic here, because first off its gradient can change, which explains why some of the depositional sequences in Avalon are somewhat different from Parkway, somewhat different from East Shugart. But there's an awful lot of similarities between most of them.

You can change this gradient, you can increase the tortuosity of channel coming in, or the path followed down the gradient. If you increase that, you change energy levels locally in the transport direction. What that does is that sometimes you'll be depositing in, sometimes you'll be eroding here, sometimes you'll be transporting a certain grain size here. And you get odd mixes, which explains your variation, explains quite a bit of variation in log character.

There's one other thing that takes place in the deposition that has a lot to do with what you see in the logs and a lot to do with correlations, and that is that the deposition we're talking about here in the fan is mostly the coarsest part, because that's what's going to drop out first as you make this sudden change of energy at this change in the gradient. So you're going to get the coarsest part, which in this case means mostly larger silts and sandstones.

There's also this finely -- what I mentioned, finely particulate carbonates, finely particulate clays. These things go out, and they don't sink very fast. I mean, it takes them a long time.

These large packages of sediment that come down the drainage, as I mentioned, were environmentally controlled. They are intermittent. Some people call them catastrophic events. There's a lot of these. We've had a lot of catastrophe in the history. They come down the closest, based on rainfall back here, somewhere in the headlands. It doesn't make any difference how far away as long as the water hits it. But they're not happening all the time. They come in closest.

Between those closests, we have this finely -- fine clastic material that is slowly filtering down at a very steady rate. It can be affected by alongshore currents, but in essence it's very evenly distributed, and it's deposited in quiescent periods. It's a very, very even, very, very uniform deposition.

You can see on Exxon's 19A quite a few of these events, which, by the way, they have used, and rightly so, as a correlation measure. Here's a good example of one right here.

Q. Mr. Hanson, you're now referring to what has been introduced as Exxon Exhibit 19A, Mr. Cantrell's. Is it -- I think it's Mr. Cantrell's --

A. Anyway, these events out of this -- that type of deposition, is -- They always have to have names for it. They call it hanging flashes; at least some people do.

It makes very good time markers. I mean, you know, nice uniform correlation markers, it all came down, they have a very consistent character which is very different from the sand character, makes it very easy to use.

They also, by the way, have a function in the trapping mechanism, as they frequently are the seals for the reservoirs.

Q. Do you see a seal in the reservoir where Mr. Cantrell has put the base of the Upper Cherry Canyon in the FV3?

A. Not on that track. There's a stop upward migration, but it -- Actually, since he's going up to that well from the east, or in this case from the east, it makes it a little tough to figure out how it will trap to the northwest. But of course, the cross-section stops --

Q. Well, when you look at the FV3 log itself, and we're looking at this 82 feet below Mr. Cantrell's base for that reservoir, do you see anything that physically separates out what he picks for the base of that reservoir from what you have picked as the base?

A. Yes, sir, we have -- It's one correlation that I indicated on cross-section B-B'.

Q. Is that a seal to the reservoir where he's got a floor to the reservoir that precludes contribution from the

82 feet that you're adding to the well?

A. There is indication of a hemipelagic there, but it's thinning very rapidly from the character which you see back to the east on that one. How you're going to do a question of, is it going to function as a seal or not, you can't tell that from the logs.

Q. When you look at the porosity values on the log, do you see any change in the porosity as you move through this interval where you have the 82 feet to give you a material difference between the 55 feet he has added to the well?

A. It's better.

Q. The lower part where you're trying to add is better?

A. The porosity is better.

Q. Are you using the 10-percent cutoff?

A. Yeah.

Q. Do you see any reason to exclude the 82 feet that you're proposing be added?

A. One of the things we haven't discussed yet is that we did mention some of that cut and fill on this thing happens in these fans.

As I said, you've got these nice regional markers that go through and carry quite well. By the way, they carry a little better between fields than they do in the fields. But you've still got some macrointervals that nobody's going to argue on the correlation, and we all use them to get from one field to another and to get around in the field.

You run into some problems when you start breaking down these correlations too far. And every geologist I know, including me, is going to break them down just as far as we can, because it tells us more -- You need to go from the macro to the micro in order to try and understand as much about what happened there to cause the trap as possible.

Some of the things that occur: As you get a bigger rainfall back up here, it comes down a little bit faster. And instead of depositing when it gets here, it erodes through the pre-existing one. And it might end up laying down a pod like that, which means that a chunk of that is gone which is replaced by younger sediments. And trying to pick that up off the logs gets to be quite an exercise.

So what I like to do -- I agree with them that their logs are essentially point sources of information. They are.

But you've got -- Like in this case, you've got an area where you've got quite a number of wells. Now, they -- In their package they have a whole series of downdip cross-sections, going from -- I think they number them from the southwest up to the northeast.

What I like to do is that and then grid -- I put together as many cross-sections as I possibly can when I'm working on a field, especially in the development phases, as possible. And believe me, every time you drill another well in the field you find out something you didn't know before.

Q. In your opinion, has Exxon made a geologic mistake with regards to the net thickness attributable to the FV3 well?

A. Yes, sir, I think they have in the FV3 well. And I would refer both to the maps that Jerry and I prepared and to their maps, the differences between those maps and their maps, 6, 7 and to a certain extent 19.

Q. Describe for us -- Let's finish up with the Exxon Exhibit 19A. Describe for us where you believe the Exxon geologic interpretation is flawed.

A. Well, my opinion, based upon my correlation with B-B', which goes from the WM4, which they have here, to the FV3, they've interjected the C5, which is north of the east-west line between the FV -- excuse me, it's south of the east-west line from the FV3 to the WM4, and the well is not -- the CV5 is nowhere near as similar to either one of the wells as the FV3 is to the WM4.

The main reason for the correlation section we prepared, B-B', is twofold. One, it's the closest east offset, and I wanted to make the correlation from east to west or vice versa. And the other one, the other thing, is that there is similarities between the two logs that are very apparent to me, and I was trying to extrapolate Exxon's correlations into my client's well.

Also, just as an aside, we're approaching the edge of the field here, and there are some sedimentally established structural controls on deposition in these submarine canyon fans, and I find it a little tough to figure out how that particular unit could thin, coming off the edge of the field.

Q. When you examine the Exxon geologic information, do you find any other occasions in the report where we have this event where there is this thinning of the Upper Cherry Canyon by moving the bottom of the reservoir upwards?

A. One other, the cross-section immediately south of the one in the FV3, I believe it is, FV3. But immediately south of the FV3 is the ZG1, and those two wells are the only ones that -- or those two cross-sections that ended in that area are the only ones that thinned anomolously over this area.

Q. Everything else that you've looked at agrees with where you would put the base of the Upper Cherry Canyon reservoir?

A. There was one -- There was more of an accounting error than anything else. They double-labeled the middle and the lower top, I believe. And one other database is -- the computer picked the wrong one and labeled that.

Q. Let's look at Premier Exhibit 1 now and have you identify and describe the A-A' cross-section.

A. Okay. Cross-section A-A' is a cross-section running north to south, roughly, from the Antwell Mesa Macho 1 through the FV Number 1, the FV Number 2, to the FV3, to the ZG1.

Q. Describe for us the conclusions that you reach from examining this cross-section.

A. Since it's running essentially downdip and essentially really didn't -- Now, we didn't put any super-detailed correlation on it, and we did put both Exxon's and our correlations on it. And again, Exxon's are dashed in red, and ours are the black lines. And this, again is a -- This is a structural section hung on plus 750.

It's interesting that at some points -- for instance, at the FV Number 2 -- we agree on all the picks. And -- Let's see, we agree on all but one pick back up at the Macho, and that's a tough pick anyway. It's all we have at the top, base of the Goat Seep. It's behind-pipe log, and the information has been sketchy.

Since we're going down the deposition, or out into the fan, and it's been my experience that the correlations I've made better describe what should happen to the thicknesses of those grosser intervals, those picks on those correlations, and --

Q. Mr. Cantrell's objective, as I recall it, was to have integrity with a regional concept of deposition in terms of his analysis.

A. I can give you an example of what I'm talking about when going from the regional to the micro.

When we were working on East Shugart ten years ago, we were in the development phase. Conoco was a partner. And we were getting some really good rolls, and everybody was very interested in the information that we were developing out of the development phase of the project and everything else. And of course, Conoco wanted to go explore, and they felt that since we had found this one, that we ought to work together on the same project to explore for these things.

Well, Conoco was putting out seismic, and we were -- we didn't have any seismic. But they wanted to shoot a regional cross-section -- they wanted to shoot a regional section.

I suggested that since we were probably going to be looking for markers that would be associated with the

Delaware, we ought to tune frequency response so that we could read the smaller events in the 3000- to 5000-foot range, these thinner events.

They ran a test line, played with the frequencies, came up with a frequency range that actually could read 500- and 600-foot hemipelagics at 3500 to 5000 feet. I was kind of surprised, maybe it will work. So we did participate with them on a regional seismic line. And on depositional strike -- in other words, we were staying in this area where I felt like we were going to find the best oil regime because of the higher energy -- the change. I wanted some more of these submarine canyon fans.

Well, they shot the line, they processed the data, hired a geophysicist, nice young guy with a master's degree. He works this stuff up, and he calls me up one day and he says, Can you come down here and look at this? He says, I've got a real problem.

So I went down. Just to say for -- as an example, two or three of these things, we made sure that -- one through two. One was the old shoot at the original small one there north of Greenwood, and then through our east shooter we extended it some in both directions.

He says, How come when I get west of the East Shugart and east of the East Shugart all my markers carry, but when I get to the field I lose half of them?

He's lost half of them because that's where all the energy was taking place, and that's where all the erosion is, and that's what you're looking for. You're looking for a loss of regional markers. And that's a real good place to look for a submarine canyon fan.

So anyway, what I'm saying is, is that, yes, you need a regional framework to be able to work the formations. But as you go into these higher-energy depositional areas, which are the productive fields, you're bound to lose some of those because of the erosive nature of the deposition.

Q. Let's go to Premier Exhibit 3. Mr. Hanson, I've placed before you on a display board, Premier Exhibit 3. Would you identify and describe that display for us?

A. It is a cross-section, structural cross-section hung on plus 7950 feet. It runs from the FV3 to the Yates EP7, to the Yates EP6.

Q. What's your geologic conclusion with regards to this display? What are you trying to demonstrate?

A. The main thing is, again from another vector, from north-northeast, coming across the depositional strike of the field, there's what I believe to be an anomalous thinning of the interval in question, basically from the Upper Cherry to the Downlap.

Q. If you follow the Exxon interpretation?

A. If you follow the Exxon interpretation. There is an anomalous thickening of that part below it. There is an anomalous thinning of that part above it.

And the amount of difference is very difficult to explain in the framework of the deposition of these fans. They just -- I've looked at a lot of them, and I haven't seen anything, especially on the periphery of the fan, that looked anything like that. You don't get a sudden thickening at the edge and then a sudden thinning at the edge.

You would expect, as you're coming off of the -- First off, this thing is frameworked on the Brushy Canyon, which is a -- the term they use now is low stand, but it's a nice smooth depositional feature. In other words, it was the first one of these things to happen.

They tend to be very uniform, they tend to be very smooth on the top. Part of that reason is, they were deposited -- There was a eustatic sea-level change. They were deposited in deeper water, they're subject to less turbulence, less diagenesis, they don't get any alongshore current action and below-wave face.

So they get nice and smooth, and they provide a nice little hump which provides structural components into the subsequent deposition of the Upper Brushy and Cherry Canyon, that deposition which takes place at a lower sea level, after a eustatic sea-level change.

It makes it very difficult to explain what correlations in red are shown.

Q. And those are the Exxon correlations?

A. Yes, sir.

Q. What's your ultimate conclusion about this issue, Mr. Hanson?

A. Well, I believe that the FV3 and the zone in question has an extra gross of 84 feet, an extra net of 82 feet.

And there are other reasons for believing that correlation too. For instance, going back to B-B', which is right here, there's a zone on here -- excuse me, I'll hold it up so I can see it -- that is probably like in the WM4.

Q. And how is that identified on the exhibit? Is it shaded in a particular color?

A. It's shaded in pink right here.

Q. All right. And it's at approximately what footage on that log, so the record will be clear on what you're saying?

A. It is approximately 2718 to 2728.

Q. This is the east offset to the FP3?

A. FP3.

Q. This is the WM4, and what have you concluded?

A. That well is perforated in three places. It's perforated at a thin zone centering at 2527, another zone at -- it looks like about 2582 to maybe 2586, and then the zone in question that I just mentioned.

All those zones were treated together, and the well is productive. I'm not aware of its current production, but I know that it is productive.

Q. What have you concluded about the WM4 well, then, at that point?

A. Based on my correlations and some other information I'm going to present here in a minute, I believe that that specific lower zone, mainly the one from 2718 to 2728, in the WM4, is correlative to a zone in the FV3, which runs on the wireline measured from approximately 2776 down to 2790. Now, what's interesting about that particular zone is that when the FV3 was drilled, they had an unmanned hot-water gas detector in the doghouse that also recorded footage.

Q. Now, we're talking about an interval that correlates to the 82 feet, some portion of the 82 feet?

A. Yes, this -- In the FV3, this correlative interval in the FV3 is in that 82 feet.

Q. And it's in the 82 feet that's excluded under the Exxon geologic analysis for the Upper Cherry Canyon reservoir?

A. Yes, it is.

Q. All right. Let's move some of these displays and have you return to your seat, and then we'll talk about the mud log.

All right, sir, let's turn to what has been marked as Exhibit 4. Hand you one, sir. Here's the rest of the package.

Mr. Hanson, identify for the record what we have submitted as Premier Exhibit 4.

A. Premier Exhibit 4 is a drilling-time log, plotted for the FV3 from 2740 down to 2840, 100-foot interval.

Q. What is the source of this data?

A. That is -- comes off of the previously mentioned drilling time and hot-water record, which is Exhibit 5.

Q. All right, let's look at Exhibit 5. Describe for us how you've used Exhibit 4 and Exhibit 5 as your analysis with regards to this topic.

A. All right. Well, Exhibit 5 is the base data from which Exhibit 4 was prepared. On the right side of the paper tape track, you'll see a whole lot of little tick marks.

Q. You're looking at Exhibit 5?

A. Yes, sir.

Q. All right.

A. You will also see that it's on a graph paper which has some horizontal lines drawn on it at regular intervals. Those lines -- this thing is on a drum which is run by a clock, and those horizontal lines are 15 minutes apart in real time.

Q. All right, sir. What's the point?

A. That means that every time the drill pipe penetrates a foot, it causes a pen to click over and record a tick on the right side of this paper tape. The paper tape is turning at a constant rate of speed. Basically, one unit, one of these divisions every 15 minutes.

So by measuring the distance between individual ticks, you can accurately measure the penetration rate of the bit, which has quite a bit of significance to interpreting the well while you're drilling.

Q. So what's the point?

A. All right, on the left side there's another line, which is connected to a hot-water gas detector. It just detects methane; it does not detect any of the other gases. And it's quite qualitative in this case. It just tells you when there's none or when there's just background and when you get an anomalous increase.

And at a point on this one -- well, we must -- One other thing here. The calibration for the drilling time, as far as what the ticks actually mean, there's some white squares here that have penciled numbers in them. For instance, 2723, 2752, 2784. Those are connections. In other words, when they make a connection of the drill pipe every, roughly, 32 feet, the driller -- He keeps the tally board and he -- at the same time he marks down his connection on the tally board, he marks down the depth at which he made that connection, right onto the paper tape, so that we have a way of working backward and forward from each connection to count up the ticks and get an accurate indication of what foot each tick is talking about that it recorded.

Q. How does this information aid your analysis then?

A. Well, first off, on the right side, when the recorder makes a tick of a specific foot, the bit is -- Let's just take an example, 2785. That means the bit is 2785 feet below the rig.

At that same time -- at that point, 2785 feet below the rig, the mud is coming out of the bit, it is picking up the samples, including any gas samples that come from that foot, and starting its trip back up the hole in the annular space on the outside of the drill pipe.

It takes a certain amount of time to get from 2785 back up to the surface, which is where the gas detector is. So we have to figure out how long it took to get from the bottom to the top, so that the gas detector, which then records on the tape -- We know that even though the bottom of that kick says that it's at 2780-something, whatever it is on here, it's actually 15 -- in this case, 15 minutes further back up the tape.

Q. You need to go through this analytical process so that you can determine exactly where in the reservoir you actually are?

A. Exactly where the gas sample came from, exactly. I need to know where the gas sample came from relative to drill pipe measure.

Q. And were you able to do that?

A. Yes, sir.

Q. And where do you put this?

A. It correlates -- as the drill pipe correlates to the wireline -- which, by the way, the wireline correlates seven foot low to drill-pipe measure, and that's not an unusual occurrence. As a matter of fact, it's unusual if drill pipe and wireline ever comes out the same.

Anyway, figuring that seven-foot difference, going back to the log, this gas show correlates back into the same break we were talking about from 2718 to 2720 -- No, that was in the -- wrong -- In our well, in the FV3 --

Q. Here it is, Stu.

A. In the FV3, it correlates back to a sand zone from 2776 to 2790.

Q. Again, we're below where Exxon has picked the base of the Upper Cherry Canyon?

A. Yes, sir. And the fact that this thing -- We got a gas show during drilling, the zone looks very similar -- The whole interval looks similar, but this particular zone looks very similar to that one that's perforated in the productive well, the WM4 to the east.

And then of course there's one other indication that they're similar. There were some sidewall cores were shot by Gulf Oil.

Q. Let's go to the core information. We have that as --

A. -- 5A.

Q. -- Exhibit 5A. Let's turn your attention to 5A.

A. 5A is a core analysis report prepared by Petroleum Reservoir Engineering of Dallas, Texas, and it is an analysis of a number of sidewall cores that were shot in the FV3. These are sidewall percussion cores, and they shoot a hollow bullet into the wall and try to recover a sample of the formation.

Q. What's the conclusion with regards --

A. There were two samples --

Q. -- to the core?

A. There were two samples shot in the interval in question. One was at 2781 and one was at 2783. We can be quite sure that that's where they came from, because sidewall core locations are usually the last thing shot in a wireline operation, and the footages at which they're shot is usually shot off of the first logging run. So what I'm saying is that they're tied into the same wireline measure as the logs that we're reading.

And those two samples are described, among other things, as being too broken for analysis. Well, that's just a -- That's a standard abbreviation used, and what it usually means in the Delaware is that the sand was too unconsolidated to get enough of it back to the surface for much more than a gas detection. They did get enough back to the surface for gas detection, and they have a number of cores that were shot through the Upper Cherry Canyon interval. Those are the only two that were shot in the zone in question.

All of the cores that were shot in the Upper Cherry Canyon interval -- and by the way, three others that were shot down to a depth -- the deepest one being 2878, all showed gas-detection readings. In other words, they were run by -- the samples themselves were run past the gas detector, and methane was detected coming out of the samples.

And that is a -- this is a -- They give you a quantitative number, but it's a qualitative amount, because these samples have been subject to washing in the mud system coming up, they've been subject to some mechanical deformation when they push them out of the core plugs with the press, and then finally they get sealed in a bottle. There's a lot of handling involved.

But anyway, qualitatively cores 2781 and 2783 showed by far the highest gas concentrations of any of those cores shot in the Upper Cherry Canyon, and this zone is untested.

Q. And where is this interval in relation to the reservoir we're dealing with, as shown on B-B'?

A. It's below Mr. Cantrell's pick and above my pick.

Q. What's your conclusion?

A. I believe that this is -- This is part of the 84 feet that I attribute to being in that Upper Cherry Canyon sequence that we're discussing.

Q. Do you have any reservations as a geologist about the inclusion of that 82 net feet pay in the Upper Cherry Canyon reservoir for that --

A. No, sir, I'm basing it mostly on -- you know, we've been through the whole discussion of going from macro to micro and everything else. But that correlation section B-B' tells me everything I need to know as far as having a very high level of confidence in the correlations that I have made. And I started out at the WM4 using Exxon's correlations. I was just extrapolating them into the FV3.

Q. How does this information, then, fit into your work so that we can ultimately lead to what you recommend the Commission do in terms of a distribution of hydrocarbon pore volume, insofar as it affects the Premier tracts and the affected Yates tracts?

A. Well, it's going to make some very obvious changes in reserves attributed to the Premier acreage, I would think. I mean, I know it does.

There's one other change. We mentioned that accounting error -- well, it shouldn't be -- Anyway, it's a tabular error in the method for calculating numbers for the FV1. They had a -- In their numbers they used 185 feet for the gross thickness. Off of their own correlations, it's actually 215 feet, which adds a gross of 30 feet, a net of 20 feet, above -- an average porosity of 12.9 percent, and the water saturation is within the range that Exxon's using for their reserve calculations.

Q. As to what well are you describing this error?

A. This is the FV1 to the north of the FV3 on Tract 6.

Q. Okay. There is a clerical error, then, in how they have tabulated --

A. Certainly the way that it --

Q. -- that information?

A. Yes, and I -- it doesn't even -- it's not even --

it's -- Section G?

Q. Yeah. The point is --

A. It's in there.

Q. -- on the FV1 well --

A. The FV1 --

Q. -- by Exxon's own work, it has been shorted some --

A. -- 82 feet.

Q. On the FV1?

A. No, excuse me, the FV1, by Exxon's own -- by a mistake in their report has been shorted 30 gross feet and 20 net feet.

Q. Let's go on and have you unfold what's in front of you as Exhibit 6 and Exhibit 6A.

A. Exhibit 6 is Upper Cherry Canyon thickness, Downlap to base interval. And 6A -- prepared by Jerry Harrington and myself. And 6B is the same interval as prepared by Exxon, their Map 7 in their package.

Q. All right, make sure we're looking at the same position.

A. 6, 6A.

Q. 6 is your work product and 6A is the Exxon work product?

A. Yes, sir.

Q. And we're looking at what reservoir?

A. We're looking at the gross thickness of the Upper Cherry Canyon from the Downlap to the base of the Cherry Canyon.

Q. All right. Let's look at your Exhibit 6. Describe for us what you've done, now, with the FV3 information on the additional net feet of pay in this reservoir, and how you have contoured that value into the gross map for that reservoir.

A. Well, as I mentioned before, we made the two corrections, the FV1, which is just a mechanical correction, the FV3, based on a different -- on our different pick in correlation.

And what it shows in the overview of the field is a very typical-looking Delaware fan shape, submarine canyon fan shape. It doesn't have any anomalous thickenings or thinnings around the edge. It has a fairly well discernible apex or axis, whichever you prefer. It has a fairly regular shape. It narrows toward the northwest, it widens on the downdip end, which is what one -- everything you would expect it to do. The --

Q. Contrast that to the -- Exxon's gross map, Exhibit 6A.

A. Exxon's map, because -- Well, no question about it, it's because of the difference in the correlation pick. And by the way, they mentioned that the ZG1 looks a lot like the FV3. I agree. And if you make -- Whichever pick you make in one, you're going to make the same pick in the other.

But what that is, that puts a very anomalous little contoured area around those two wells on their map of the same interval we just discussed.

Q. When we look at the gross map, then, for the Upper Cherry Canyon as you have recontoured the lines on your exhibit, do we have Exxon's proposed western boundary for the unit contiguous, for what you would conclude to be the reservoir limits for the western boundary of the Upper Cherry Canyon?

A. Well, no, because looking at the rest of the field, the rest of the contours on this basis -- and I realize that they brought in -- you know, there's other maps that were involved in picking a final unit outline. But this adds some reservoir thickness. And this is gross interval. We're not talking porosity, net feet or hydrocarbon net feet yet anyway. But I would expect -- Based on just this map, you would have to change the unit interval somewhat to the northwest.

Q. As well as to the west?

A. Yes, to the west and northwest.

Q. All right.

A. To incorporate the same thicknesses of section that were incorporated in the rest of the unit.

Q. Before we go on to the next set of exhibits, is -- We're going to go from the gross now to the net in the Upper Cherry Canyon. Are those the next displays?

Before you do that, Mr. Hanson, I've allowed you to make a verbal mistake, I think. When we talked about the FV1 and the fact that their engineering report by your analysis had shorted the FV1 by 20 net feet, we were talking about the Upper Cherry Canyon. I believe I have misspoken. That is attributable to the Brushy Canyon, is it not?

A. I believe so.

Q. All right. And that will affect, then --

A. That's right, it is.

Q. -- other calculations.

Let's go now to 7 and 7A. We've talked about the gross distribution. Let's look at the net distribution, using 7, which I think we stamped as the Premier exhibit --

A. Yeah.

Q. -- and 7A, I think, is the corresponding Exxon exhibit. Did I get the numbers the same on your set?

A. Yes, sir.

Q. All right. Let's start with your Exhibit 7. Describe what you've done when you've gone from gross to net.

A. Okay. Okay, those are maps -- both are maps of the Upper Cherry Canyon hydrocarbon thick- -- porosity thickness, which is a number incorporating porosity cutoffs and water saturations that is supposed to net out an amount of oil in place.

Q. Now, you've used those same parameters that Mr. Cantrell used in terms of getting from gross to net?

A. As a matter of fact, in most of the field we used his numbers.

Q. All right. Describe for us what's happened under your distribution, then, of the net, as contrasted to his distribution.

A. The only change, again, is in the area of the FV3. And again, they have a -- On their map, it's a little confused, because they put the limits of primary production outlined on there, but if you'll look in the area of the FV3 on Exhibit 7A, you'll see a kind of an anomalous thinning that comes well into the field area.

And again, the only difference -- That's the only difference of going back to the map that Mr. Harrington and I prepared. That anomalous thinning isn't there anymore. We're back to the regular fan shape, a smooth outline, a more typical-looking field outline.

Q. All right. Let's take us from the net, now, to a pore-volume map. In terms of assisting the engineer now, how do we get from the net to a geologic map that is useful to the consulting engineer when we're looking at calculating oil in place?

A. Well, that's what these maps are.

Q. All right.

A. We didn't -- The pore volume map was in Exxon's package.

This is -- You go from gross thickness to net thickness using a porosity cutoff, calculate water saturations. Then you figure an average water saturation, which the engineers have to do, but it can cause geologists a little bit of problem every once in a while. And then calculate the hydrocarbon porosity thickness. And that's what the last two maps that we just discussed are.

Q. I didn't have a set in front of me, and so I've misspoken when I characterized those as net maps. They are in fact hydrocarbon?

A. This is the engineer's base data for volumetrics when he goes in to figure out oil in place, to the best of my understanding.

Q. All right. Let's go back and have you summarize for me on the FV3, based upon your knowledge of an experience in dealing with these Delaware wells, potential drilling and completion problems for these types of wells that this Gulf well may be characteristic of.

A. Okay. First off, Delaware wells, by the nature of the formation, are difficult to drill and complete successfully in every attempt. Statistics on them are getting better, and we're learning more about the procedures than we used to know.

Specifically, the FV3 was drilled in 1984, I believe, according to the log heading on the log that I saw, RMF was .13 at 78 degrees fahrenheit. That's fresh water. You don't hit the Delaware sand with fresh water.

Q. Is that what Gulf did?

A. Yeah, sure did.

Q. What happens?

A. It swells the clays. There's two kinds of clays in particular. One is called vermiculite and one is called cerussite, which they used to call Montrolonite when I went to school, but things change.

They swell, specifically -- especially the vermiculite. Cerussites can drill anywhere -- or swell anywhere from three to ten times their original volume, and vermiculites can swell up to 30 times their original volume.

And even if you're only looking at 10- to 15-percent clay cut in the sand, you can sure knock the -- you can ruin the permeability of a reservoir section with that kind of swelling very easily.

Q. In your geologic opinion, has that occurred in this well that Gulf drilled?
A. In my opinion, it has a very high possibility that that did occur, yes.
Q. Can you as a geologist condemn the Premier tract based upon the production results from the FV3 well? Are you going to condemn it?
A. There's a couple other things that happened that --
Q. Well, I'm not through yet.
A. Well, I know, but I want to get all of the physical things that happened to the well first, and then I'll -- because no, I can't condemn that well.
A. You can't condemn the acreage?
A. Right.
Q. You condemn the well?
A. I can condemn that bore. But I can't condemn --
Q. All right. Let's talk about the other reasons that condemn that wellbore.
A. They frac'd that well. I've got the frac report right in front of me. First, they're talking about a perforated interval which is not very large. Here it is. They perforate 2710 to 2716, 2723 to 2725, and 2738 to 2740, with a total of 28 holes. Then they went through cleanup with acid, acidizing, a few other odds and ends.

But then they frac'd it. And I would like to read a little bit about that frac. They went down 2 7/8 tubing with 38,000 gallons of gel -- they call it Quality Foam, but it's gel -- and 64,000 pounds of 20-40 sand. They did it in stages. They first stage is 18,000 gallons at 25 barrels a minute and injection pressure of 3400 pounds and zero sand. They're cracking it. Then they hit it with 4000 gallons of gel, 25 gallons -- 25 barrels per minute, excuse me, 3500 pounds injection pressure, one pound of proppant per -- one pound of sand per gallon.

Next stage was 4000 -- it says gallons, but it doesn't -- well, it probably does mean gallons. 4000 gallons, 25 barrels a minute, 4000 pounds of injection pressure, two pounds per gallon of sand.

They go from another 4000 gallons at 4300 pounds with three pounds per -- Now staging the sand, as far as mixture, is normal procedure. As a matter of fact, the new equipment stages it continuously so you don't have to go incrementally in these jumps.

But anyway, they ended up on the last one, and this is the one that I think makes a lot of difference -- The last 4000 gallons, 25 barrels a minute at 5100 pounds with six pounds per gallon of sand, and they had pump trouble because of too much sand, and it shut down the operation.

5100 pounds, and their deepest perforation is at 2740. The normal pressure gradient is .5 pounds per foot. Frac height on that job is almost back to the surface.

The only way you could accurately calculate frac height would be to run a long Stasonic in there, calculate modulus, calculate Poisson's ratio, and then calculate frac height.

But the Delaware doesn't have much of a frac height in the best of times, and this is incredible.

Q. So what's the point?

A. It means that this thing is probably communicated almost back up to the surface casing.

Q. So what effect does that have?

A. That means it can get water from anywhere.

Q. What else is on your list that condemns this wellbore?

A. They made a temperature survey after the acid job, and it shows communicate going up.

Q. What do you conclude?

A. That this well -- It wasn't drilled to be a Delaware well, it wasn't drilled as a Delaware well, and because of what they did to it during drilling operations and in completion operations, the chances of becoming a Delaware well were not very good, and there's very little chance of remediation on this bore.

Q. What effect, if any, does the results of this well, under your conclusion, have on the potential productivity of Tract 6, that Exxon wants included in the unit?

A. Well, it makes the valuation based on existing production pretty difficult, because you don't know exactly what this well could do.

They have accurately stated that the wells to the south didn't do very good either, and in every field you look at you're always going to get to the edge where the wells start getting worse. It always happens.

But this well has not been properly drilled, properly completed, and therefore not properly evaluated. And I cannot make the statement that it's the same as the wells to the south as far as its potential production. I don't think anybody really knows what its potential production capacity is.

It's similar enough to wells to the east that have done very well, that you could say that it could be a lot better than it is. Log analysis suggests that it's comparable to better wells than it is, much better wells.

There is reason to believe it should be better, and there's reason to believe it was damaged.

MR. KELLAHIN: Mr. Chairman, that concludes my examination of Mr. Hanson.

We move the introduction of his Exhibits 1 through 7 -- I believe it's 7A.

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

Okay, if you -- We'll take about a ten-, fifteen-minute break before cross.

(Thereupon, a recess was taken at 10:35 a.m.)

(The following proceedings had at 10:55 a.m.)

CHAIRMAN LEMAY: We will resume. We're all here now. We will resume with the cross-examination.

Mr. Bruce?

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Hanson, in looking at your geology, I understood that you were talking about the Upper Cherry Canyon. Did you have any dispute with Exxon over the Upper Brushy Canyon geology?

A. Nothing significant, sir.

Q. And looking at your Exhibit 7, if I understand this exhibit, what you're basically saying is that the FV3 and ZG1 wells should be as good as these Yates and Exxon wells to the east and southeast?

A. That's not exactly what I said. I think that -- I have a problem with correlation, using Exxon's correlation, coming back to those wells. I believe that the correlations that I have used are more correct in the case of those two wells.

I didn't spend a lot of time on the ZG1 past the correlation stage, but in the FV3 I believe there's more section in the correlative interval under discussion than reflected in the Exxon geology, and I believe that it contains some untested potential in that section.

Q. In the Upper Cherry Canyon?

A. Yes, sir.

MR. BRUCE: I have nothing further, Mr. Chairman.

CHAIRMAN LEMAY: Mr. Carr?

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

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Is there any indication in the files why Gulf did not originally perforate that zone of 2781-2783?

A. In those records that I've seen, Commissioner, there is no indication of that. But there were -- I only saw partial -- I did not see a complete file on the well.

Q. How much does it cost these days to drill and equip and complete a Delaware well?

A. I'm five years out of date on that stuff. Our last costs were running in the -- for a well of equivalent depth with a similar casing program, were running in the quarter-of-a-million to $325,000 range --

Q. Okay.

A. -- five years ago.

Q. Right. So we can assume that that's an extremely conservative figure right now?

A. Yes, ma'am.

Q. I'm just thinking, the economics of drilling a new well for only primary production, for what reserves are there, is it economic, in your opinion?

A. That would take a little bit more work than I've done on this one. In other words, you'd have to figure out what goals you had, what kind of a production rate could you expect, what kind of primary producible reserves might be there if the well was drilled properly.

It would take a little bit more work than what I've done, and that's -- Economics on that scale are left to engineers and operators.

COMMISSIONER BAILEY: Thank you.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yes, sir, Mr. Hanson, you've been in this Delaware play for a considerable time, and I imagine you've kept current with it. Did you look at Exxon's proposed CO_2 reserves?

A. Yes, sir, as reflected in --

Q. Yeah.

A. -- the report --

Q. Yeah, let's just say those are accurate. What would a successful project here do to the Delaware play in general?

A. It would establish a precedent for CO_2 flooding that I think would be important.

COMMISSIONER WEISS: Yeah, it would be. That's the only question I had. Thank you.

THE WITNESS: Yes, sir.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Hanson, do you have any experience in formulas at all on waterflood, primary, secondary, tertiary?

A. Mr. Chairman, I've seen some general numbers in the literature. I'm a member of the SPE, and I read the articles that they publish on that stuff.

Q. Do you know what the Parkway Delaware formula was for that?

A. No, sir, I don't, because that was formulated within a year after I left the company that was operating that production property.

Q. Your cross-section -- Well, I guess the first question I had is, did you do a log evaluation of the Gulf well, as far as porosity and saturations? Is that within the oil range, water range, marginal?

A. Are we speaking of the 2774 to -90 zone, sir?

Q. Yes.

A. Yes, it is.

Q. It fits --

A. Yes, sir.

Q. -- something that should be perforated?

A. Yes, sir.

Q. Because below that it looks water-bearing, doesn't it?

A. Well, yes, it does. Well, we've got two questions we need to address on this one.

It gets wetter as you go down from there, true. The zone that's in question is well within my parameters, and it's well within Exxon's parameters. Exxon's parameters for their flood reserves are rather more forgiving than you could probably use on primary production, because they're going to get to recycle their own water and they can cut themselves a lot of slack on that basis, which goes with any waterflood project. It's very normal.

The other thing is that when Exxon or any reservoir engineer calculates a section for oil in place, which he uses then to calculate moveable -- water-moveable reserves and things like that, they use an average water saturation for the section in question, and they'll have a cutoff on SW, which will be in the bottom of the zone.

The Delaware typically has a -- all reservoirs have a capillary transition zone in them, and that's a function of pore geometry, pore size, throat size, fractures, whether or not -- There are all kinds of things.

But in the Delaware, because of the pore geometry and the pore size, grain size, these transition zones can be quite long. I've calculated some, in some of the other fields I've worked on, that were as much as 70 or 80 feet from economic cutoff to water-free production. And the zone you're talking about, the small zone that we were discussing up at the top, -74 to -90, fits within -- right off the log analysis, fits within parameters for primary production. The bold zone fits within Exxon's parameters for secondary recovery.

Q. I was really thinking more in terms of primary, because the Yates well to the south -- Did they perforate the correlative interval? I can't remember. At 2758 to 2842?

A. I don't have that information, Commissioner. Or Mr. Chairman, excuse me.

Q. I think they -- Well, I guess the point is, it's a lousy well to the south, the same --

A. The ZG1?

Q. Yeah.

A. It's shown as a gas well. The symbol is a gas well on this map, Exhibit Number 7 that I'm looking at.

Q. The cross-section shows it to be perforated, made 6000 barrels, I think, according to the testimony.

A. I remember the testimony.

Q. Very similar, yeah, cum to what we've got up here.

A. But again, I don't know how they drilled it or how they treated it.

Q. Is it possible on your wireline -- Your measurements, your 15-minute lag time, you feel pretty good about that.

What about recycling some gas above as your cuttings and mud is coming up? Is that possible with your gas shows?

A. What you normally see on a Delaware -- Let me refer back to Exhibit Number 5. You can see some gas associated at different places, sometimes referred to as connection gas, and that's going to be some of these small spikes, and they're going to occur every 30 to 32 feet. They're pretty easy to figure out which ones they are. And actually, it can help you establish lag time.

Lag time in this case, though, was established by an engineer contacting a drilling contractor. He asked them what their strokes per minute and pump pressure was, and he calculated it.

And from that depth he's not going to be very much off when he said 15 minutes --

Q. Uh-huh.

A. -- which is a reasonable lag time from that depth anyway.

Q. It sounds like they did everything kind of right on the AFE. They ran some sidewall cores, they had a logging unit out there, and then they screwed up the frac. Maybe that's why they're Chevron now and not Gulf.

A. They shouldn't have drilled it with fresh water either.

Q. Yeah, fresh water is a big -- the big one.

Just bottom-line question, Stu: Would this be a prospect you would take out and want to get drilled again, just to see, because of the way Gulf handled the first one?

A. If I was developing this field -- this would be obviously towards the end of development when you got to this phase -- I would be looking at the northwest extension of the maps that Jerry and I drew, and I would really wonder about the FV3 and what's happening between there and the FV1.

And I'm going to refer specifically to Exhibits 6 -- well, 6 would be a good place to just look at it.

There's an indication in the area north of the FV1 that -- and that is in the direction that the sediment was coming from -- that you might have a possible continuation up there.

I've got an indication that the FV3 was not properly drilled and completed, and I've got the indication of some reservoir section on the acreage of Tract 6 that I would want to evaluate before I decided I was finished developing the field.

Q. It looked like your structure, though, you're falling off. You take your pick, where you disagree with Exxon. And rather than pinch out that sand going up northwest regionally, you're draping it over a structure because you -- then you get a lower marker, which --

A. Yes, sir.

Q. Do you see any indication of water in the Cherry Canyon part of that field, downdip? I mean, the wells are making it, Yates is making it, so --

A. Yes, sir.

Q. -- would you assume there may be some --

A. Well, they're -- they also --

Q. -- some producible water in the downdip this side of it?

A. This thing, the original discovery of the Avalon was about a year before we started the East Shugart. There wasn't very much of what I would call modern drilling of the Delaware. As a matter of fact, the only production I know of that predates this from a similar type of deposition is the original Shugart well, and that was discovered by accident -- by Gulf, by the way -- back in 1958.

And what happened is, they were -- In those days they called it the snow bank. The Delaware section, they figured it was a good place to make hole. They didn't get samples, they didn't pay much attention to it.

And they were doing what they do, they were pouring the coal to the drill bit, getting some hole made, and all of a sudden -- I got this from the guy that was running Gulf's district office in Roswell when they drilled this well. I think you know who.

Anyway, all of a sudden, penetration ceased. They tripped out of the hole and the bit sub were burned off. They had a downhole fire. They were drilling with natural gas too, which made it really exciting.

Q. Now, you were with -- You were with the Esperanza thing too, so...

A. I got there right after they drilled it. They found that one by accident also.

Q. Yeah.

A. It came up the back side on them.

CHAIRMAN LEMAY: We won't reminisce anymore. Thank you. That's all the questions I have.

MR. KELLAHIN: I'd like to call Terry Payne, Mr. Chairman.

<u>TERRY D. PAYNE</u>,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. All set?

A. I think so.

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

A. My name is Terry Payne. I'm a consulting petroleum engineer.

Q. Where do you reside, sir?

A. In Austin, Texas.

Q. On prior occasions, have you testified as an expert in the field of petroleum engineering before the Oil Conservation Division?

A. Yes, sir, I have.

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

A. I have a bachelor of science degree in petroleum engineering from the University of Texas. I received that in 1985.

I have worked for Conoco, for about a year after that, in field operations. I was then employed by Chevron for approximately six years as a production engineer and as a reservoir engineer.

For the past four years I have been employed by Platt, Sparks and Associates in Austin, doing consulting petroleum engineering studies.

Q. Describe for us the general scope of your consulting engineering duties as they presently exist.

A. We are a full-service consulting engineering firm. We do work for small operators, for mid-size companies, for all of the major oil companies. I've done work for Exxon in the past. We do any type of petroleum engineering evaluation, reservoir study, we do quite a number of secondary enhanced recovery studies and unitization studies.

Q. Would your firm have the capabilities to generate an engineering study such as the Exxon study we've seen dated August of 1992?

A. Yes, we would.

Q. What were you asked to do when Ken Jones hired you?

A. Ken asked me to look at the engineering report, the study that was prepared by Exxon, to evaluate that study, and then to look at the proposed participation formula that was the resulting formula from the last hearing.

He wanted to know if we thought it was a reasonable formula and a fair formula. If so, the matter would stop there. If not, he wanted recommendations on how to make it fair.

Q. As part of your preparation, did you review the transcript and exhibits from the Division Examiner hearing of this case back in June of 1995?

A. Yes, sir, I did.

Q. And as part of your work, have you reviewed and studied not only the August, 1992, Exxon small engineering size book and then the foldout which is the geologic displays?

A. I looked at the big fat book and the one that goes with it, yes.

Q. All right. In addition to utilizing that information, what other information did you draw upon to make your analysis?

A. We looked at other public record information available in the area, production-type data, some other logs in the area. We also used some tools that we commonly use in our studies, some petroleum-engineering software and computer programs that we have in our office.

Q. When we talk about traditional parameters to be selected for purposes of determining participation within units for secondary recovery projects or tertiary recovery projects, are those terms and information familiar to you?

A. Yes, sir, they are.

Q. Do you use those on a regular, daily basis in your work?

A. Yes, we do.

Q. In addition, did you consult with and work with Stu Hanson in terms of analyzing and evaluating the geologic components that are involved in this case?

A. Yes, we did. That was one of the issues that we were aware of, was that there was a disagreement about some of the geologic picks. We evaluated the magnitude of the difference and calculated the results.

Q. And based upon all that work, you now have engineering conclusions and recommendations for the Commission?

A. Yes, sir, I do.

MR. KELLAHIN: We tender Mr. Payne as an expert witness.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) What did you find out, Mr. Payne?

A. In general, we are definitely in agreement that the field needs to be unitized. We are in agreement that waterflood is the logical next step, CO_2 is a very good likelihood in the future. There's an extremely large target here that, if we are going to recover it, CO_2 is the most likely way to do it.

We looked more and more at the engineering study done by Exxon, identified some problems with it. And at that point in time we had to make the decision -- "we" as in Premier -- to either redo the study or to see if we could take the work that had been done and fix the problems.

Exxon talked yesterday about the costs associated with doing such a study. They roughly estimated it as half a million dollars. Our costs would probably not be that high but they would be significant, to redo this entire study.

That was really not feasible for Ken, so the option was to take the work that had been done and make it fair to everyone.

Q. In your opinion, have you been able to identify the significant problems, find solutions to those problems, and come up with a conclusion in your opinion that's fair, equitable and reasonable for all interest owners?

A. We have. There are essentially two options.

The first option is to leave Premier out of the unit. That is an option. That is Ken's first choice.

If the Commission chooses to bring Ken into the unit, a revision in the formula is necessary to provide equity, and we will propose a new formula.

Q. Let's talk about the issue of the in- -- Let's talk about the boundary, let's talk about the logic of Exxon's proposed boundary, insofar as it fits into this reservoir. What's your opinion?

A. Well, we can start with Exhibit 1. It's -- As I said, we've been involved in a number of secondary recovery studies, and it is unusual to not have a reservoir-limit map that conforms more closely to the unit boundaries than we have here. When I look at Exhibit 1, the Upper --

Q. All right, let me, for the record, so you and I are not confused, I'm going to mark your engineering book --

A. Okay.

Q. -- as Exhibit 8, and then we're going to go through and talk about page numbers.

A. Okay, I'm sorry.

Q. We've gone through and --

A. All right.

Q. -- numbered the pages. So you're looking at page 1 of Exhibit 8, and the first sheet starts with page 1.

A. I will try to refer to page numbers.

Q. All right, sir, let's go.

A. Page Number 1, again, is the hydrocarbon pore volume map on the Upper Cherry Canyon reservoir. And you can see that --

Q. Well, whose map is this?

A. This is Premier Oil and Gas's interpretation of hydrocarbon pore volume.

Q. This is the one that Stu Hanson just described a while ago, I think, as Premier Exhibit 7?

A. That's correct.

Q. All right, please continue.

A. It's the same map, just on a smaller scale.

The anomalous thing here, to me, is that we see hydrocarbon pore volume up to increments of ten on the west side of the unit boundary. We see hydrocarbon pore volume in increments up to six, going across Section 25, and six looks to be a reasonable boundary over on the east side of the unit.

And we come around to the south side and we pick up some hydrocarbon pore volume increments up to four -- down to four. And really, over a large portion of the south half of Exxon's section, the volumes are much smaller, and yet those are included in the unit.

And then we move back around over to the west side, and again we just see a disagreement, a discrepancy on the unit boundary and the hydrocarbon pore volume.

Q. If you were to have the opportunity to reconfigure the size and the shape of the unit so that you could satisfy your engineering criteria, what would that criteria be and what would the shape be?

A. It would be more closely tied to hydrocarbon pore volume. Granted, that is a difficult thing to do in the Delaware, but it disappears, and we've heard testimony that it hasn't changed since 1991, and it sort of sounds like that's what they decided to do then, and instead of any analysis that's what it was going to be. It would probably be more closely tied to a true reservoir limit.

Q. When we look at Section 25, do we find the inclusion of the east half of the east half of 25 within the proposed unit to be a logical boundary for that unit?

A. Based on the analysis we have done, that does not appear to be a logical boundary.

Q. If you had the flexibility and the opportunity to put that boundary, where within Section 25, if at all, would that western boundary be?

A. I don't know if the boundary would even be on Section 25. It might be further west than that.

Q. Is Dr. Boneau's criteria of trying to have a unit that contains the entire reservoir achieved, in your opinion, by adopting the boundary as proposed by Exxon?

A. No.

Q. Let's turn to Page 2. What are we seeing on page 2?

A. Page 2 is our interpretation of the hydrocarbon pore volume in the Lower Cherry Canyon-Upper Brushy. Again, it's the map that Stu testified to just a moment ago, just on a smaller scale.

There is better agreement in this area with the hydrocarbon pore volume distribution, but there are still some problems. For instance, just south of our acreage, the east half of the east half of 25, there are hydrocarbon pore volumes as small as four, whereas the acreage just west of the unit boundary on Premier's tract is not included.

So again, this one does tie better to the hydrocarbon pore volume contours, but there are some inequities.

Q. With regards to hydrocarbon pore volume, what is your engineering conclusion about the pay outside of the unit, as proposed by Exxon?

A. There appears to be pay outside the unit that would fall within a reservoir limit definition that is not included within the unit boundary.

Q. Let's turn to page 3. Identify and describe what you're showing on page 3.

A. Before we leave the --

Q. Yeah.

A. -- the unit, it -- Well, we can do that later, that's fine. Page 3 is fine.

Page 3 is simply taken from Exxon's Exhibit 7 in the previous hearing. I think it was incorporated in the record yesterday and made a part of this hearing. But this is just a schematic diagram of the zones that are productive within the unitized interval. We have the Upper Cherry Canyon, the Middle Cherry Canyon, the Upper Brushy and the Lower Brushy.

And if you were to superimpose the unit boundary on these wellbores, you would see that seven of the 37 wells produce from other than the proposed injection intervals. And the point being, is that there are a significant number of wells that have produced from other intervals that are not considered in this unitization. The reserves are given no credit. In this case, the operator loses the ability to produce those reserves, and they are not considered in this formula in any way, shape or form.

There are an additional three wells just outside the unit that have produced from the Lower Brushy, so it appears that there are a significant number of wells. It may not be significant volumes of production to this day, but ten years ago we didn't think the Delaware was worth anything at all.

So we're talking about a unit that's probably going to be in place for the next 60 years. We've heard about the great difficulty to put the boundary together, to put the formula together. And to neglect these intervals may be short-sighted. So it's a concern that we have.

Q. Let's turn to the issue of the waterflood target, and we're looking at all these multiple opportunities in the Delaware. Focus for our attention what are the flood targets, then, under Exxon's plan?

A. Okay, these numbers are directly from Exxon's report, and what we have done is summarize the waterflood target reserves by operator acreage. It's not working interest owner; it's merely who operated what acreage prior to unitization.

So for instance, in Premier, they operated the four tracts that are the east half of the east half of 25. On those four tracts, according to Exxon's report, we had approximately 3 million barrels of waterflood target reserves.

Now, it's important to know what waterflood target reserves are. We heard testimony yesterday about the criteria for whether or not a formation can be waterflooded. The key component is the residual oil saturation to water. And in the Exxon analysis they've used 35 percent.

So anywhere we have oil saturation greater than 35 percent and -- significantly higher enough so that you can produce enough oil that it's economic, you have waterflood target oil. If the oil saturation is higher than 35 percent, it's classified as target reserves. So that is the methodology that we used.

I think they also applied a sweep efficiency to that calculation to come up with these absolute numbers.

But you can see that there are 3 million barrels of waterflood target reserves on the Premier tract. That's a significant amount of oil that is mobile. It is floodable with water. And yet Exxon chooses not to flood those tracts.

Q. Now, when we're talking about this waterflood target reserves on page 4, this does not yet roll in workover reserves under the allocation system, does it?

A. That is correct. These are just waterflood target reserves.

Q. And you got this off of their Exhibit E-6, I think. It's in the exhibit book.

A. That's correct.

Q. All right.

A. Now, the first question I had is, why is Exxon not wanting to flood these tracts? If we could -- I hope these are available. If we could look back at some of the maps in Exxon's study, the big book, and if we could start with Map 17, we're looking at --

A. Yes.

Q. -- the large --

A. It's either in the large one, or it's in the back of Volume 10, but whichever one is easiest.

Q. And we're looking at Map 17?

A. At Map 17.

Q. Okay. It says the "Upper Cherry Canyon - Average Porosity".

A. Average porosity. Through the course of my analysis I was wondering, why is Exxon not proposing to flood these tracts? There's 3 million barrels of target reserves on here. I thought, well, it must be because of a difference in porosity or water saturation.

But as you look, the east half of the east half of 25 has a porosity contour running through there of 14 percent. That is equal to or better than the porosity that's on Exxon's tract, Section 31. In fact, we have an area of 12 percent down there. And I think that's an area that they carve out not to flood, but still we have 14-

percent porosity on our tract, just like theirs.

Q. Does that give you any reason, then, to distinguish the boundary -- I'm sorry, the inclusion of the Premier tracts for waterflood purposes, based upon porosity values?

A. This gives you no reason to exclude them, no, sir, it does not.

Q. So if you were to design the waterflood project using the average porosity value for the Upper Cherry Canyon, there is certainly every reason to include those tracts in the waterflood flood patterns?

A. That would be part of your decision. But this would not exclude it.

Q. All right, what's the next part of the decision process?

A. All right, if we turn to Map 19 -- and again, we're going to look at the Upper Cherry Canyon. This time, we're going to look at average water saturation.

Now, you see the east half of the east half of 25 starts out around the FV3 at 40-percent water saturation, and it maintains about 40 percent, all the way up through the acreage proposed for inclusion, and it's 40 to 50 percent over the rest of Section 25.

If you look down in Section 31 again, we have significantly higher water saturations, and yet they propose to flood that area. As a reservoir engineer, it doesn't make sense. It seems inconsistent.

Q. When we go back to your page 4, then, let's see the net effect of Exxon's proposal. If we look at the Premier tract, the waterflood target reserves are almost 3 million. That represents 8-percent-plus of the field target waterflood reserves, except Premier gets zero credit for those reserves under this system?

A. That's exactly right. Now, still that did not satisfy my question of, why is this acreage not included? I went through the same process on the Lower Cherry, Upper Brushy, and Exxon does not have an average porosity map in their report.

I was curious about that. I went back through their report and found the range of porosities that they calculate, and they're all between 12 and 15 percent. So there's just not a big variation in porosity, so we don't really need to map it.

But it is important to look back at Map 12. If that one is available, we might take a quick look at it.

Q. Okay, let me turn back to Map 12. This is the "Lower Cherry/Upper Brushy Canyon - Average Water Saturation"?

A. That's right.

Q. All right, why is this important?

A. Well, again, the single most important component in whether or not you're going to flood an area is the water saturation. So I was curious why are certain areas being flooded, why are others not?

And again, on the Premier acreage -- Now, these saturations are higher, there's no question about that. But here on our acreage we have saturations from 65 to about 75 percent. Again, Section 31 has saturations of the same magnitude.

So again, I don't see a reason to exclude the Premier tract from the waterflood of this project at this point in time. I just -- At this point I'm still struggling for the answer.

And it wasn't until I saw -- talked with Ken more about it and saw the temperature survey of the FV3 well after the stimulation.

Q. All right, let me stop you for a second before we talk about the temperature survey.

What's your engineering judgment and conclusions about whether there's mobile oil underneath Tract 6?

A. It's my opinion that there is, and my opinion is consistent with the Exxon mapping that is presented in their exhibits.

Q. Mr. Beuhler yesterday talked about the direct relationship between the water saturation and the residual oil -- saturation to oil. I think that's part of the analysis that you technical people go through to decide if you've got, in fact, recoverable oil?

A. It's very important.

Q. All right. Yet when you look at their modeling effect on the engineering work, what do you see?

A. Well, that's where we -- That's when it became clear to me why they were not wanting to waterflood the Premier tracts.

Q. All right, sir.

A. In their modeling work, what Exxon has done is, they take a 40-acre tract with the well in the center, and this is something that's typically done. They then take the 40 acres and split it into quarters and model a single 10-acre quarter of it.

And for the purposes of predicting secondary recovery, they put a producer at the top corner and put the injector at the bottom corner and model that 10 acres. They then flood it and see how it performs.

Mr. Beuhler's work on the history match, when he initially put in the 38.5-percent water saturation that was calculated from the log analysis, he could not get a history match, because there was too much water produced from the FV3 well.

So what he did to get a history match was increase the water saturation in his model almost up to 60 percent. He totally disregarded not only his analysis of the log, but he totally disregarded the mapping done by his geologist. Nowhere on that map in that area do you see 60-percent water saturation.

Again, the reason he had to do that was to match the water production that had been reported in that well.

Q. Once he gets that match, then, he can calculate and determine whether under that scenario it's economic to waterflood Tract 6?

A. If you've got a 60-percent water saturation in the model, which means there's 40 percent oil, and your residual oil saturation to water is 35 percent, there's only a five-percent swing in there. So no, that probably is why he got the results that he got.

Q. What's the problem with the model?

A. There's really no problem with the model. The real problem is that he didn't -- he testified yesterday that he didn't look at any data that indicated to him that there was water potentially coming from outside his modeled interval in the Delaware.

Q. He attributed all that production, that water cut, based upon the water production Gulf had in the FV3 well, cranked that into the model, and it now becomes uneconomic to flood for that target oil?

A. That's correct.

Q. All right. What did you find in your research with regards to the potential source of that water?

A. We found a -- There is available a temperature survey that Gulf ran on the well after it was perforated and treated, and --

Q. Do you have a copy of that?

A. I have a copy of that.

Q. All right.

A. It's a two-page exhibit.

MR. KELLAHIN: Mr. Chairman, we're going to mark this for introduction as Premier Exhibit 9. It is not currently marked on the exhibits, but it --

MR. BRUCE: I think it should be 10.

MR. KELLAHIN: Ten? The engineering book is 8.

MR. BRUCE: Well, I have an exhibit -- Mr. Hanson's last exhibit was marked Exhibit 8 that you gave to me.

MR. KELLAHIN: All right. Let me correct the record, Mr. Chairman.

Mr. Bruce reminds me that Exhibit 8 should be the last of Mr. Hanson's exhibit. That was his porosity distribution map. I need to, with your assistance, have you reidentify Mr. Payne's engineering work as Exhibit 9, and then we will mark the temperature survey as Exhibit 10, and I'm back in the sequence here.

Thank you, Jim.

Q. (By Mr. Kellahin) All right, Terry, let's talk about Exhibit 10, the temperature survey.

A. Okay. I apologize for Exhibit 10. It may be difficult to read. I didn't want to make any corrections myself, because this is exactly how the log appears. It's a gamma-ray temperature survey run on the well after it was stimulated, and we'll look at the second page here in a minute.

But the conclusion down at the very bottom of the first page is that the gamma ray and temperatures indicate treated interval from 2710 to -45 and channel up to 2665. So that is consistent with what you would expect from such a large treatment that was done on that well. It's consistent with Mr. Hanson's expectations, and this is data that seems to indicate that that's what happened.

But the second page of this exhibit, again, shows that -- the basic data from which that conclusion is derived. You see the gamma-ray curve is increased, not only in the perforated interval. The perforations are designated in the depth column by circles, the dashed gamma-ray curve, you see the increase not only in the interval but above. And you see the decrease in the temperature curve, not only in the treated interval but also above.

Over on the far right-hand side it's got a darkened area with the treated interval, and then arrows indicating a channel up to 2665.

Q. So how are you going to resolve this?

A. Well, the importance of this information is that it provides an explanation for the anomalous production behavior that we saw in the FV3 well.

If you calculate by log analysis 38.5-percent water saturation and yet you get the production performance that we've seen in this well, it ought to throw up a red flag and you ought to say, what's causing this?. Not just simply throw the log analysis away. You need to ask, why is this causing -- what's causing -- what's happening here?

In the modeling work that's not what was done. We -- The water saturation was simply increased from 30.5 percent up to 60 percent, and that really dictated the results of the model at that point in time.

Q. Let me have you turn to page 5, and let's look at this illustration. Would you identify and describe what we're seeing on page 5?

A. Okay. Page 5 is simply a color representation of the numerical values on page 4, and it shows that Premier has eight percent of the waterflood target oil in place within the unit boundary. Again, these are from Exxon's report. And yet we get no credit, zero barrels.

Exxon, on the other hand, has 41 percent of the waterflood target, and yet through the 50-percent participation part of the formula, they're assigned almost 60 percent of the credit for the waterflood reserves. Yates has almost 50 percent of the target, yet gets only 40 percent of the credit. And MWJ has just over one percent of the target and no credit, because their tracts aren't being flooded either.

Q. What's your conclusions about the reliability of utilizing Exxon's conclusion with regards to the waterflood target oil insofar as it affects Premier?

A. I think their conclusions about target oil are valid. There is waterflood target oil on these tracts. The exclusion of Premier's tracts from the waterflood, based on the result of this model, is premature. The FV3 wellbore cannot be condemned at this time. There are reserves on that tract that are just as floodable as other reserves in the field. So we can't just make the decision not to flood those tracts.

Q. While we're talking about the FV3 well, Mr. Hanson characterized that wellbore as a failed attempt to appropriately test the Delaware at that location. Does that wellbore serve any purpose at this point, or should we just plug and abandon it?

A. No, we don't need to plug and abandon it now. There are other zones that have potential in that well. It was, Mr. Hanson testified, not designed to be a Delaware producer, but there are things that we can potentially still do to salvage that well, even if there are problems.

This channel could be squeezed and reperforated. It's 5-1/2-inch casing, so potentially a smaller liner could be run. But it's not time to plug the well at this point.

Q. Let's turn to the topic of the CO_2 target oil, if you will. If you'll turn to page 6, let's have you discuss that topic.

A. We'll go through this one a lot quicker, but it's the same rationale as the waterflood target reserves. These are taken, again, from the Exxon report.

Q. Let me stop you right there. Why is it the same rationale when we're looking at the CO_2 target oil, as opposed to the waterflood target oil?

A. Well, it's a function of the residual oil saturation to this process.

In Exxon's report they have used a residual oil saturation to the miscible flood of ten percent. So wherever we have remaining oil saturation above that, it's a target.

But again, where we have conflicting saturations, we've excluded some areas and not others. But you find the target and you calculate the target in the same manner you do as the waterflood.

Q. Using their numbers, what's the conclusion here on comparing the waterflood -- the CO_2 target reserves?

A. It may be helpful to also look at page 7, which again is a color display of these numbers.

Premier has just over 10 million barrels of CO_2 target reserves on their tracts, and that represents 5.88, almost 6 percent, of the field total. And yet their CO_2 participation factor, the 25 percent of the total, only gives them 4.08-percent participation.

Again, Exxon has 56 percent of the field target and yet they get 60 percent of the participation. Yates comes out pretty equal at around 35, 36 percent. MWJ has 1.6 percent of the target and yet gets .42-percent participation.

Q. All right. All of your discussion up to now involves numbers that are derived based upon Exxon's geology; is that not true?

A. That's correct.

Q. We have not substituted yet any change with regards to Mr. Hanson's conclusion about the distribution of hydrocarbon pore volume share?

A. Up to this point, we have not done any of that, because the point of these exhibits is that the unit as it is formed today and the participation formula that we're using is unfair to Premier. We could make that point using even Exxon's study. So we did not need to incorporate any of that in these exhibits.

Q. Let's turn to page 8 and look at these categories, the effect of the formula and the assumptions.

A. All right. What we've done here is analyze how this formula affects the various tracts and again using Exxon's numbers of 1.626 million barrels that will be produced from the four Premier tracts under the CO_2 flood.

We've looked at case one, and under the current scenario none of those barrels are produced during primary, none of those barrels are produced during waterflood. They're all produced during CO_2. As a result, the Premier tracts are zeroed out under 75 percent of the participation and only receive credit under the 25-percent portion of the CO_2. The resulting participation is 1.019 percent.

Well, clearly we can see that there is waterflood target oil on their tracts. Exxon even calculates it. The water --

Q. On the Premier tract?

A. On the Premier tract, that's right. And this exhibit here just merely makes the assumption that 25 percent of the oil, mobile oil, is produced during the waterflood phase, instead of CO_2.

And as you can see, as you work through the calculation, if that were to occur, Premier's participation would more than triple.

The formula is a function of timing. These reserves are mobile waterflood reserves, but because they are not produced during the waterflood phase, they are devalued. If they were produced during the waterflood phase, even 25 percent of them, Premier's participation would more than triple.

Q. What's your conclusion?

A. It's -- Well, it's an unusual formula. We'll talk about that more. But it is unfair to the Premier tracts, and that is why Premier wants out of this unit at this time.

Q. Let's look at the topic of if Premier is removed, what happens to the remaining tracts that are in the unit? If you'll turn behind the blue sheet, let's go to the next section in the book and, starting with page 9 --

A. Okay.

Q. -- have you identify for us what you have studied in terms of trying to determine what effect, if any, exists when the Premier tract is excluded.

A. Okay. I have to the best of my ability reproduced G-19 from the Exxon report into a spreadsheet, and I believe that all the numbers are the same. I think they all check out. And that's stated down there on the bottom -- the footnote of the page, that that's the source of that data. And we've kept the same titles, everything, even the EUR and RUR units are in KBO. We would normally put MBO for thousand barrels of oil, but --

Q. Terry, I think you've misspoken. Have you not used the G-24 spreadsheet?

A. Well, I'm getting to that.

Q. I'm sorry.

A. Yeah.

Q. I'm ahead of you then.

A. Yeah. Just below the EUR and RUR, the units are KBO. It says, as amended in 2-15-93 letter. And that is what we're talking about. We've been talking about this G-19, G-24. G24 does not appear in the Exxon report. It was mailed under correspondence dated 2-15-93.

And what G-24 did specifically to the Premier tracts, G-19 in the report gives CO_2 reserves on the Premier tract of just over 2 million barrels, 2.060 million barrels. G-24 reduced that to the 1.626 million barrels that was on -- Exxon Exhibit 36, maybe, I forget the number. But that's the number that they're using in the formula now, not the G-19 numbers that you see in the report.

So I thought that was important to clear that up.

Q. What happened between G-19 to get us to G-24?

A. It's my understanding that they moved the placement of some of the future producers and injectors to -- just moved them a few feet one way or the other, and it resulted in some changes primarily in the CO_2 recoverable oil for each tract.

Q. All right.

A. So we have the ability to do that, that's certainly something we can do.

What we were trying to do here was on the -- The only thing that's different about this page than either G-19 or G-24 is, the far right-hand, we've calculated a resulting participation factor. And I've done that on a tract basis, and I've used the Exxon 25-50-25 formula to calculate a participation formula for each tract.

And the whole point of these next few pages is just that if we remove Premier from this unit, that all that's going to happen is, everybody else's share of the proceeds is going to go up, it's not going to go down.

Now, it does make the assumption that a co-op will be done and the reserves that are between Yates and Premier would eventually be captured. We've heard testimony that there's 2 million recoverable barrels of oil between those tracts.

There is sometimes difficulty in negotiating a co-op. There might be operational concerns on what do you do with the CO_2, how does Premier get it back over, and that kind of thing. But for 2 million barrels I think we would find a way to do it.

So this exhibit --

Q. In terms of increasing ultimate recovery from a reservoir and thereby preventing waste, the concept of these lease-line injection wells between Exxon, Yates and Premier is a viable concept that can be executed in various ways?

A. It certainly can. And you know those ways better than I do, but I think it can be almost forced upon the situation.

Q. All right, please continue. What happens?

A. Essentially -- Again, this exhibit does make the assumption that the recovery is the same for the tracts, even if we pull Premier out.

But page 10 -- What I've done beyond page 9, is tag the four tracts that Premier operates, the 1109, the 1309, 1509 and 1709, and gone through the mathematical exercise of zeroing out the CO_2 recovery for those tracts. So we've just taken those barrels out of the production from the unit. That's the only change we've made there. All the other tracts get the same recovery.

Page 11, the following page, merely contrasts the change in participation factor for each tract. The second -- We list the tract and then the participation factor as it exists now and then what happens if we remove Premier, and it's shown in graphical format on page number 12.

Q. All right, let's look at Page 12 and have you show us graphically what's happening.

A. Okay, simple concept. All we're doing is removing Premier. Logically their participation is zeroed out, it goes to zero. And the remaining tracts, their participation increases. If it's a money-making deal, they make more money. If it's, we're going to lose money on this deal, all Premier does is absorb some of that, but -- if they're in the unit.

Q. As part of your investigation of the Exxon engineering report, did you examine how they had analyzed the primary reserves for the unit?

A. Yes, I did. We -- Again, our number-one goal is to get -- We feel like Premier is not being treated fairly, and they should be excluded from the unit. If they're going to be included, we wanted to demonstrate that there are problems not only with the formula but with the numbers that are being used in the formula.

Q. Let's look at the issue, then, of the primary reserves, then, if you'll turn to page 13, have you describe this issue for us.

A. Okay. Again, this is a section of G-24, and it -- we list each tract on the far left side, and then we have the Exxon estimates of remaining ultimate reserves on each tract and the estimated ultimate recovery for each well.

Now, the fourth column over, we highlight the actual current production. And there are some wells, and they are highlighted in gray, where our production today already exceeds what Exxon has estimated. They're not big exceptions, but again, this is a number that we're using in the participation formula, and we know that those four wells are already incorrect.

Now, I realize the work was done back in 1992, but it's being presented in these exhibits here today as part of the -- today and yesterday -- as part of the participation formula, and we know they're wrong.

Q. Do you have some plots or curves that validate and verify your opinion about certain of these tracts receiving too high a credit --

A. Yes.

Q. -- for the remaining primary reserves?

A. Yes, I do.

Q. Let's look at those.

A. The last column on this sheet, we've got two things we're showing here. The actual curve production, there are wells that we already know exceed the numbers, we know those are wrong. Then we have some overstated reserve estimates, and that's what we've shown in the next few pages.

Page 14 starts out -- There's really no need to go all through all of them, but page 14 shows the data that Exxon had available on Tract 1511, the WM6, up to the time of the report, which was in the 1992-93 time frame, and the prediction of reserves that they made at that time was fine. That's the data they had, and it was fine.

But you can see what's happened to the production of that well since that time, and clearly we've overstated the reserves for Tract 1511.

Page 15, if anybody cares to do it, is out of the report and it just shows the Exxon fit on that particular well, the data that was available, and you can check it against the line that we've drawn on the curves.

We've performed the same exercise on page 16, on the Well 1915.

Page 17 is the fit that Exxon used.

Page Number 18, again, is a well where we see the estimated reserves that are being used in the report today, are based on data that we had in the 1992-93 time frame, and you can see what that well has done since then.

Q. 1919 is over on the east side of the unit?

A. That's right.

Q. And page 18 shows their fit and then what's happened to the production since they made the forecast?

A. That's correct.

Q. All right, please continue.

A. Well, there's more of the same. Page 20 shows the 2111, the forecast we made. I don't want to criticize the forecast that was made at the time, because it was probably fine with the data that we had, but it's just clear that those wells are not going to make those reserves. And that is 25-percent participation formula -- or 25 percent of the formula.

I show the same thing on page 22.

And we show another well on page 24 that was shut in for a period of time. That well certainly may come back and produce the reserves that we had forecasted, but the timing will certainly be off on that forecast.

Q. Let's turn to page 26 now and look at the topic of Exxon's calculation.

A. Let's -- One more point.

Q. Am I ahead of you?.

A. One more point on the primary reserves. These are proved producing wells. They're producing wells, the reserves would be categorized as proved producing reserves. They're very low risk. Typically, when they're evaluated they're assigned about a 95-percent probability of success. Banks, according to various surveys, will loan about 84 percent of the value for those reserves. They're extremely low risk.

And we do need to differentiate between the risk of these reserves and the value of these reserves, and I want to try to do that as we go through the various components.

But these are -- They're proved producing, by definition, and they're very low-risk.

Q. Okay, let's turn to the topic, then, of the percentage recovery of original oil in place by tract.

A. Okay.

Q. And this is using Exxon's calculation.

A. That's correct, we're still using all the information from the Exxon report. And there's a lot of information on this page.

What we have calculated is the percent recovery of original oil in place, or the recovery factor for each tract, as stated in the Exxon report. And we've grouped the tracts by operator. And what you see is a wide variety of recovery factors, and that's not surprising.

But what's important to me is comparing the offset tracts. If you look at Premier, the four Premier tracts on page 26, if we start with the 1109, the Exxon predicted recovery as a percentage of oil in place is about 8 percent, 7.92 percent.

If we move over to Tract 1111 --

Q. That's the east offset to the Premier tract?

A. The east offset, which was operated by Yates. We have a predicted recovery on that tract of about 15 percent, just almost double the recovery of the 1109.

If we compare the 1309 to the 1311, again a Yates offset, it's 16 percent of the oil in place, to 37 percent of the oil in place, again over double.

If we compare the 1509 to the 1511, we've got 16 percent to about 32 percent. Again, it's double the recovery. And we soften the -- Well, I'll explain why in a minute.

1709 compared to 1711, 1709 again is the tract that has the FV3 wellbore, and it is the subject of the modeling work that was done by Exxon, and they predict an ultimate recovery of under 6 percent for that well, based on their model, based on their model alone. And yet on the 1711, which is the offset tract, they predict a 30-percent recovery.

Now, it might be important to go back to the modeling for a second. When they did their quarter-acre modeling, where they had production data, they -- It's my understanding from the report they adjusted the water saturation however they needed to adjust it to match production. Where they didn't have existing production data, no adjustment was made. So it's a hit-and-miss type adjustment.

And then we take that -- and I have the same reservations that Dr. Boneau had about the modeling work. We take that quarter-acre model and plug it in in various places around the field and use it to predict what this field is going to do in the future.

And we really ignore the best data that I think we have, and that's the log data. It's the most consistent data. We talk about all the wells going through all the intervals. It's relatively modern log data. We analyze it in a consistent manner, and it provides a relative value, if you will, of each tract. It's a consistent treatment to every tract.

The modeling is an inconsistent treatment. Where we have data, we use it. Where we don't have data, we make any adjustments, and it's an inconsistent treatment.

Q. The final comparison, I think, is the 1709 to the 1909?

A. That's correct. The 1709, again, based on the modeling, gets a recovery factor of under 6 percent. The

1909, just to the south of it, gets a recovery factor of over 11 percent. These very low recovery factors are direct predictions from the model, and they're a function of the input data that we have.

Q. All right, let's look at Exhibit Page 27.

A. We'll go through this real quick. It's just -- It's the same type of display using primary recovery alone. Obviously, the 1709, they're only contributing -- or they're only giving it credit for the 5000 barrels it's produced so far, so it has a very low primary recovery.

Some of the offset tracts -- and we'll see another exhibit that displays this in a little bit more detail later on, but really the point to make from this s that there are much higher primary recovery factors on some offset tracts than even the Premier.

Q. Page 28?

A. Same point on Exhibit 28. There are some very high recovery factors, as a percentage of original in place -- I'm saying very high, they're -- in a relative manner. They're a higher recovery than the Premier tract, even though they're direct offsets.

So Premier gets obviously no credit for waterflood oil. They're not, according to the Exxon proposal, risking those -- or flooding that acreage at all.

MR. KELLAHIN: Mr. Chairman, this would be, if you desire to do so, a logical place for Mr. Payne and I to interrupt his testimony. I see by my watch it's about lunchtime. I suspect that he and I have another hour to go before I finish with his discussion, and -- Would you like to have a lunch hour now, or do you want to try to work through this?

CHAIRMAN LEMAY: Okay, we'll take a break, come back at one o'clock.

(Thereupon, a recess was taken at 11:57 a.m.)

(The following proceedings had at 1:03 p.m.)

CHAIRMAN LEMAY: Let's continue. Mr. Payne, Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

Q. (By Mr. Kellahin) Mr. Payne, let's turn to the topic of the workover reserves. Let's start that discussion.

Let me direct your attention back to your exhibit book. It's Premier Exhibit 9, and we're looking at page 29.

From your perspective as a reservoir engineer with experience in putting together units and doing the engineering work, analyze for us the issue of the workover reserves.

A. Okay, what we've listed here are all of the wells that are proposed for workover in the Exxon engineering report, Exhibit 10. The well name, the tract name, the zone that is the target. The zone actually comes from the waterflood AFE. That's how we know which zone they're after.

We also list the original oil in place in that zone as per the report, the workover reserves, and then calculate a recovery factor, that that recovery represents from the given zone.

And we just start with the EP7. There's already been considerable discussion about that well. 266,000, 267,000 barrels of workover reserves, a recovery factor from the Upper Cherry Canyon of 10.5 percent.

We have the remark on there that that's already been done. We might want to go into that well just a little bit more, and I think one of the cross-sections that Mr. Hanson has is C-C'.

MR. JONES: They're labeled 1, 2, 3, Terry.

MR. KELLAHIN: Which one are you looking for?

THE WITNESS: Here it is.

Q. (By Mr. Kellahin) Okay. Drawing our attention, Mr. Payne, back to Premier Exhibit Number 3, you're looking at the cross-section Mr. Hanson sponsored a while ago?

A. That's correct, and the middle log on this cross-section is the EP7. And what we've highlighted on here are the attempts that have already been done on this well to recover these 267,000 barrels of workover reserves.

By the way, the current recovery of this well is about 1600 barrels of oil total, and I think February of this year was the last month that it produced, at least production data that we could get.

Initially, the well was completed down here from 2796 to 2836. It was acidized with 1500 gallons of acid and was swabbed dry. There was a small show of oil and gas, but it was swabbed dry.

They came back up, they eventually set a bridge plug in here between -- perforated this zone from 2662 to 2686, acidized with 1500 gallons of acid again, and this alone swabbed dry with no show of an oil or gas.

And at that point they came up here and perforated this zone, the upper zone, 2558 to 2572, acidized and frac'd it with 22,000 pounds of sand. And this is the zone that is currently producing and has made the 1600 barrels of oil.

So there was a question about whether or not this zone had been adequately tested in the Upper Cherry Canyon, what has -- certainly been perforated across all the zones that you had significant porosity responses on. Not every foot in the entire interval has been perforated, but certainly perforated the best looking zones.

Q. What's your conclusion about the appropriateness of including a workover reserve potential for Tract 1111 of the 266,000 barrels of oil?

A. Well, I think those reserves are high. Those reserves may ultimately be recovered, but they should not be put into the workover reserve category.

And again, those are -- workover reserves, it's just merely coming up the well and perforating behind-pipe pay. And by most -- really, by every definition those would be considered primary reserves. They would not be considered workover reserves, they would be considered -- they would actually be classified as proved behind-pipe reserves.

And I want to talk some more about risk factors because those are important. But the risk associated with behind-pipe reserves is typically about 75 percent. We talked about the producing being even higher than that. Proved behind-pipe is typically about 75 percent, loan value is about 55 percent,just for some numbers.

In contrast, in this field, since we have not really done a pilot study -- We've done an engineering study on these -- on the workover in CO_2 reserves, but we haven't done a pilot study. It would be hard to classify those enhanced recovery or improved recovery reserves as proved. We would probably have to put those into the probable category, either behind pipe in existing wells or undeveloped where we still have to drill it.

But that risk factor would be between about 20 and 25 percent, as far as probability of success. So we go from proved producing at about 95 percent to proved behind-pipe at 75, down to these probable reserves at about 19 to 25 percent, something like that.

As far as risk associated with the CO_2 versus the waterflood, by definition, at this point in time there wouldn't be a significant difference in the risk in those reserves, because the methodology that we have used to predict them is the same for each case. It's a model prediction. We've used the same information, the same analogy, we don't have any more information about the probability of the waterflood working than the CO_2.

So really by definition you would classify them both as probable either behind-pipe or undeveloped. So you would assign a similar risk factor to the waterflood and the CO_2.

Q. Do you have any opinions or comments concerning the Exxon method of taking the workover reserves as a category and putting them together with the waterflood target oil?

A. Well, again, there's a big discrepancy in the risk associated with those reserve categories. So to lump them both into the 50-percent participation for the formula is inconsistent.

Q. Let's turn to page 30. You've reproduced a copy of Exxon's Exhibit G-20 out of their engineering book, have you, sir?

A. Yeah. One more comment on these reserves. Obviously, there's a significant amount of reserves attributed to these workovers, and again the timing is critical. This formula, putting all these reserves into the workover category, is critical. We -- I think the oil is mobile, it's there, it can be produced, but probably not just by workover.

Q. Page 30?

A. Okay, page 30 is taken from the Exxon report. It's Exhibit G-20, and probably the best place to start is actually the chart on the bottom of the page. And what this is, is a theoretical recovery factor as a percentage of original oil in place, versus water saturation. And as you intuitively would expect, the recovery factor is higher at the lower water saturations.

This is a calculation that you can make using the numbers given down at the bottom, residual oil to waterflood of 35 percent, residual oil to the miscible process of 10 percent, and then the sweep efficiencies, secondary 70 percent, tertiary of 40 percent. You can make this calculation.

If you look at this chart at a water saturation value of 38.5 percent, which is what we calculated for the FV3 in the Upper Cherry Canyon zone, you would predict a recovery factor of about 46 percent from this theoretical chart. Now, theoretical, but that's the kind of number you'd be looking for.

If we go to the chart on the top of the page, this is an oil recovery versus initial water saturation, from the simulation model. It's based on the Upper Cherry zone. And again, if we enter that chart at water saturation of about 38.5 percent, you would predict a primary plus secondary recovery factor of over 30 percent. So even with the model, if we had the right water saturation in there, we would predict over 30-percent recovery.

But as we talked about before, to match the performance that we saw in the FV3, the water saturation in the model was adjusted up to almost 60 percent. And as you can see, the recovery factor is much lower. So that model matches the performance, but we've talked about the problems with the performance of the FV3.

So this -- Again, this is a situation where the model results didn't match the geology. It made me wonder what's going on with this well and led to the temperature survey in the FV3.

Q. Do you have a display that demonstrates your analysis of the Exxon data with regards to recovery factors versus water saturations?

A. Yes, I do.

Q. And what's the point? Why are we looking at this issue on Exhibit Page 31?

A. Page 31 is a companion to page 30, and what I've done here is take the recovery factors for the various tracts and compared it to an average water saturation of the two zones.

Since the predicting work was done based on both zones contributing, I couldn't see what amount of production was coming from each zone, so I had to keep them together like it was done in the Exxon report.

But I did -- I was able to calculate the recovery as a percentage of oil in place, and that's on the Y axis. And then plotted that versus the weighted average water saturation of the two zones.

And what you see is, the green triangles are the predicted performance for the Premier tracts. And they all, without exception -- The way you need to look at this chart is, pick a water saturation, any water saturation, and then compare the recoveries of the various tracts.

Now, from the charts on the previous page, seem to kind of indicate that if you have a water saturation, you have a single recovery that goes with it, a unique value for that. Well, you know, in real life that's not really going to happen.

But for instance, if you look at the 55- to 60-percent water saturation range, which is where the weighted average of the Premier tracts fall, all of our predicted recovery factors are much lower than other tracts with similar weighted saturations. And again, it's a product of the modeling, and the Premier tracts are given a much lower recovery factor than other similar tracts, even with the same water saturation.

Q. All right, sir, anything else about page 31?

A. Not about 31. No, that's it.

Q. All right. You've made a comparison of future production to the assigned participation percentages used by Exxon in their report?

A. Yes, I have.

Q. All right. And that's the topic of page 32 and I believe 33?

A. Yes, 33 is a companion graph to 32.

Again, it's important to distinguish between the acreage, and the analysis I've done here is an operator-acreage basis, it's not a working-interest basis. I've heard Exxon talk about getting 74 percent of the oil or something like that. That's not what this reflects. It's just what the tracts operated by Exxon -- what their share was.

And what it's meant to show is that the Premier tracts who have a formula assigned participation factor of the 1.019 percent actually produce 3.3 percent of the future reserves from the field. To me, this is a very important test as to whether or not the formula treats all the tracts fairly, because --

Q. Why do you assign importance to this analysis in determining whether the tracts are receiving relative value and therefore being treated fairly?

A. Well, I think future production is a very important consideration in the relative value of each tract. And when you do compare percentage of future production to the percentage of participation, Premier lags by -- It's a factor of three to one. Exxon gets a participation factor of about 65 percent, and yet they only produce about 61 percent of the reserves. You know, it's 3- or 4-percent difference. But at the 60-percent level, that's not as significant as it is at the 1-percent level.

Yates is 34 to 35, and MWJ is .12 to .34.

Q. When you as a consulting engineer are examining this type of issue for other clients concerning whether a participation formula is fair or not, does this particular analysis become what you would characterize to be the true test of that formula?

A. It -- Yes, it is. It is a very important consideration, and it's a formula that we could not recommend when you get this disparity.

Q. Turn to page 33, and let's see this illustrated in a different fashion.

A. I think it's 34 and 35.

Q. I'm sorry, I was looking at 33. You have --

A. Okay, 34 and 35 is just another comparison of reserve category and percentage of future participation -- I'm sorry, production.

What we're showing here is that the primary reserves, the remaining primary reserves as defined by Exxon, account for only 2.4 percent of the future production from the unit, and yet they receive a 25-percent participation factor.

The chart on page 35 goes on to show that the secondary recovery, the waterflood and workover recovery, is about 17 percent of the future production, but it's got a 50-percent factor.

The tertiary reserves are 81 percent of the future production, and yet they've only got a 25-percent participation.

Q. When you're looking at pages 34 and 35, you're looking at the percentage of production versus the percentage under the factor?

A. That's correct.

Q. And these are out of balance?

A. Again, we're out of balance.

Q. Let's look at relative value now. Let's turn to the topic within pages 36 through 40 and look at this comparison of relative value.

A. Okay.

Q. Describe for us what you're doing and then lead us through the analysis.

A. Well, the -- from a business standpoint, if you want to talk about relative value, you're probably going to boil down to dollars at some point. And what we wanted to do here was to compare the future revenue from the waterflood and primary recovery versus the future revenue from the CO_2 flood.

So using the Exxon waterflood AFE, where the factors are shown on page 39, I simply took the production stream that they have estimated, the price forecasting that they have used, and their cost projections for the operation of the unit and then proceeded through the calculation of determining a before-income-tax net cash flow for the project. And the cumulative before-income-tax net cash flow for the waterflood is the $263-million figure that's shown on page 36.

It's also shown in graphical display on page 37. Page 37 is a net cash flow versus time relationship.

I did the same -- went through the same procedure using the information in waterflood AFE, and at the back of Exhibit 10, the Exxon report, as far as their projections for the CO_2 flood. I didn't change any costs or worry about the price or anything, because what I was concerned about, again, was the relative value of the two projects.

And when I ran the numbers for the CO_2 flood, it came up to be a total of the $1.3 billion. We're talking huge numbers here. So to get the incremental value of the CO_2 flood, I subtracted the total, the $1.3 billion, from the future primary and waterflood of $263 million and got the incremental value of the CO_2 flood alone, and that's right at a billion dollars.

What I was interested in was the relationship back on page 36, because as you see on page 36, we list the values of each of the projects and the percentage of the total value, and the future primary reserves and waterflood represents 20 percent of the value from a net cash flow basis, whereas the CO_2 flood represents 80 percent of the value.

And the participation formula weighting is almost directly opposite. The future primary and waterflood gets 75-percent weighting. That's the 25 plus the 50. And the

CO_2 flood gets only 25-percent.

Q. What's your engineering opinion and judgment about the appropriateness of the Exxon-proposed formula for the unit?

A. It's a formula that does not accurately assign relative value to the various tracts.

Q. In determining what to do, did you analyze and consider traditional values to be included in any participation formula?

A. Yes, I did.

Q. When we talk about traditional values, what would they be?

A. Well, we have them listed on page 41, but it's -- Things that are more traditional are things like original oil in place, things like current rate. There is -- A remaining reserve factor is considered a normal factor. Acreage, target reserves.

Really, you can do it on anything you want to do it on. But these are a list of things -- Dr. Boneau talked yesterday about ten or eleven things that are normal factors. This would be a list of things that we would consider normal factors to use in unitization.

Q. As part of your analysis, did you examine the participation formula and the factors used in the Parkway-Delaware unit?

A. Yes, sir, I did. Our firm was actually involved in the study prior to doing the waterflood for the Parkway-Delaware field. It's -- The formula was approved in Case Number 10,618, if anybody wants to check that.

But the formula in the Parkway-Delaware is 40 percent recoverable oil, 35 percent remaining oil, 5 percent usable wells -- it's five factors here, it will make sense in a minute -- 10 percent recoverable gas, and 10 percent -- the remaining 10 percent is remaining gas. And I hope all that adds up to 100 percent. I think it does.

But the Parkway-Delaware formula is very similar to the formula that we have here, the remaining oil component and remaining gas component.

Q. You mean here, the one you're about to propose?

A. I'm getting ahead of myself, you're exactly right. We probably should do that first.

Q. All right. Let's talk about your proposal, and then let's come back in and compare that to the Parkway Delaware formula.

A. Okay.

Q. Let's go through page 41. Describe what you're doing.

A. Okay. Again, this is a list of what we consider to be a little bit more normal values. And on the left-hand side of the page we've listed them all, and then on the center and over to the right we've broken down each operator's acreage. And again, we're on page 41.

Q. And we're looking at the operator's acreage, simply because that's the way the stuff comes out of their engineering book?

A. Well, and also it's important to me to look at it on a tract-by-tract basis. I, of course, care whose working interest is in what tract, but that's not important for determining relative value. It's important to look at each tract on a stand-alone basis.

Q. Well, that was what I was trying to ask, and I didn't do a very good job of it. When you as a consulting engineer are looking at relative values, you don't care who owns or operates any particular tract; you're looking at tract relationships and their value as to a particular reserve component or a parameter?

A. That's exactly right, and that's -- That's the only way we get to do the work that we get to do, is to be impartial on those values and come up with a fair formula, what treats each tract fairly.

But again, what I wanted to do was list all of these factors. It's original oil in place, cumulative oil production to 1-1-93 -- and I picked that date because that was essentially the date of the Exxon evaluation. So it was cumulative oil production as of 1-1-93.

We looked at the January, 1993, oil production rate, again, because -- looking for a date to be consistent with the Exxon report. We looked at the initial potential rate, we looked at number of wells per tract, we looked at remaining primary reserves. And this is right from the Exxon report. The only thing that I have done differently here is, I consider primary reserves to be the remaining recoverable reserves from the Exxon report, plus the workover reserves. I put those into a primary category.

We looked at total lease acreage, we looked at the waterflood target from the Exxon report, the CO_2 target from the Exxon report, the waterflood reserves, CO_2 reserves, future barrels produced, and total barrels produced.

So we looked at all those factors.

Q. Now, when you get down to the waterflood reserves, you have subtracted the workover reserves from that row and put it in the remaining primary reserves?

A. That's correct.

Q. All right.

A. That's a good point.

Q. There's a shift there?

A. There is a shift, you're right.

Q. When you do that, now, you've gone down through future barrels produced, total barrels produced. Take us across a row and see what happens in each of the columns.

A. Okay. Well, let's look at the two that were most relevant to me. The first one was future barrels produced, from the Exxon report.

If you go across, the Premier acreage, according to the report in the future, was going to produce 1.626 million barrels, which was 3.3 percent of the total future production. The Exxon acreage was going to produce almost 30 million barrels; that's 60 percent. Yates acreage, about -- just under 18 million barrels, and that's 35 percent. And the MWJ acreage, 167,000 barrels; that's .34 percent.

So it's -- Again, going back to the Premier, the 1.626 million barrels is 3.3 percent of that total on the far right-hand side, the 49 million barrels.

Q. Hold that thought for a moment. Find the Premier acreage as to future barrels produced in that row. You get 3.3 percent?

A. Yes.

Q. The very bottom row of the spreadsheet is your recommendation to the Commission for a participation formula, is it not?

A. Yes, it is.

Q. All right. We'll come back to the formula in a minute, but the net result of applying that formula, in terms of analyzing relative value for future barrels produced, results in what happening to the Premier share under that percentage? When you look at the proposed participation factor, at the bottom of the Premier row --

A. Right.

Q. -- it's 3.42 percent?

A. That's correct.

Q. And how does that compare back up to the future barrels produced for their operated tracts?

A. It's very close to the value of future production.

Now, the other thing that was important to me was, how does the average value of all of these components, these 13 components, how does that stack up?

And if you look on the average column, or row, which is the second from the bottom, if you average all of these components together, Premier has roughly 3.5 percent, giving each of these factors equal weighting. They have 3.5 percent of all of these, they have 3.3 percent of the future production.

So when we looked at this, it was my opinion that we didn't need to go back and re-do this entire study to correct the problems with the study. We needed to address the formula. And by addressing the problems with the formula, we could arrive at an adequate participation.

Q. Are you satisfied, then, under your proposed formula, that relative value is appropriately assigned to the Premier-operated tracts?

A. Yes, I am.

Q. Let's look at the Exxon-operated tracts and look at future barrels produced, total barrels produced, the average, and then the percentage under your proposed formula.

A. Okay. Future barrels produced, Exxon gets about -- just over 60 percent. As far as the average of all these, they're at 61 percent. And the proposed participation factor gives them just over 59. So again, we're in very close agreement there.

Q. The Yates-operated tract?

A. Future barrels produced, Yates has 35.74 percent. On the average of all these factors, they have 34 percent. And with our proposed formula, they get 36 percent. So again, very good agreement.

Q. And then finally the MWJ-operated tracts?

A. MWJ is .34 on the future barrels, 1.28 on the average, and 1.09 as per the proposed formula. So again, we're in very good agreement.

Q. Let's go to the bottom of that spreadsheet, and tell us the percentages and the factors you're using by which you achieve the proposed participation formula.

A. Okay, let me also back up and say, I listened to everybody yesterday very carefully talk about what they were considering when they were designing their formulas, because I was very interested in what was behind their thinking.

Mr. Beuhler said that he was wanting to consider recovered oil, include the associated risk and the value of those reserves. I hope that's -- The best I remember, I think that's pretty close to what he said.

Dr. Boneau said he wanted to accurately reflect each tract's contribution.

So those -- And those are the exact same thoughts that we had when we were looking at this formula. And I think that when you look at future barrels produced, as well as consider the average of all of these other components, if you can design a formula that balances those out, that you've met those objectives.

So our proposed participation factor listed down at the bottom of the page, it's 50 percent original oil in place, it's 10 percent weighted on the January, 1993, rate -- I'm sorry, we're on page 41. So again, our --

Q. It's the tiny, tiny print at the very bottom?

A. It's the very, very tiny print at the very bottom of the page. Proposed factor is 50 percent original oil in place; 10 percent January, 1993, rate; 20 percent remaining primary reserves; and 20 percent of future barrels produced. And again, that should add up to 100 percent.

And if we contrast that to the formula in the Parkway-Delaware, rather than use original oil in place, at Parkway they used remaining oil in place on each tract, but -- or remaining reserves. And it was 10 percent gas, 40 percent -- 35 percent oil. So their oil-in-place component in that factor was 45 percent, ours is 40. Their component for future recovery was 40 percent recoverable oil, 10 percent recoverable gas. So that's -- 50 percent of their formula was future reserves, and in our formula it's 40 percent. So again, we're in good agreement there.

The -- well, that's -- We're in good agreement on that formula.

Q. All right. Does this analysis and proposed participation formula you're recommending to the Commission -- is this based upon the -- Exxon's interpretation of the geologic distribution of hydrocarbon pore volume for the pool?

A. Yes, sir, it is. And I think it's a very important point, and we've talked about it this morning. But the log analysis that was done on each well is done in a consistent manner across the field.

Now, I don't think anybody would sit here and say that we know water saturation is 59 percent and not 58. We don't know it to that degree of accuracy. But we have treated those tracts in a consistent manner across the field.

So when we come back and assign a relative value based on original oil in place, all the tracts have been treated fairly. Whereas, when we look at the reserves, the projections for reserves, we've done it from modeling and we've made changes, we've used data where it was available and we didn't where it wasn't. And so it's an inconsistent treatment on that basis.

But something that was important to me in asking myself, can we use the reserves at all, is, I think we can because we're talking about a recovery of about roughly 50 million barrels total from the field, out of an original oil in place of 241. So it's something just over a 20-percent recovery factor, is what we're predicting for the field. So the reserves aren't so out of line that they can't be used. So I feel like it is important to at least honor those in the formula.

Q. And this formula, in your opinion, would be consistent with the methodology approved by the Division when a Parkway-Delaware unit formula was adopted?

A. Yes, it would.

A. Let's look at the topic of should the Commission adopt Mr. Hanson's conclusion about the geology --

A. Okay.

Q. -- and therefore determine it's appropriate to redistribute reservoir share in terms of hydrocarbon pore volume.

A. Okay.

Q. Have you analyzed what to do to solve that issue?

A. Yes, I have. And that's probably a good point to make, is, this formula assumes all the data from the Exxon report. It uses none of the information that we're going to talk about here in a few minutes, as far as the geologic pick, the new oil in place, anything like that. This is based on all the information from the Exxon report. And I'm showing page 41 is what we're referring to there.

Page 42 is based on the hydrocarbon pore volume maps that were prepared by Mr. Hanson. And we list on the far left-hand side each of the tracts and the operator of those tracts, where there was a change in hydrocarbon pore volume from the Exxon maps.

And there -- for instance, then we list the reservoir, and in the Lower Cherry-Upper Brushy there were only three tracts that we felt needed to be changed. In the Upper Cherry, there were all the tracts listed here.

But what we did was look at the Exxon hydrocarbon pore volume on each of the tracts. We couldn't use the maps in their report because of all the copying that's going on. They were distorted. But we could go back to the exhibits and calculate the hydrocarbon pore volume. So that's what we did on each of these tracts.

Then, using the Premier map, we planimetered the hydrocarbon pore volume for those tracts where we felt there was a difference and came up with a ratio between the two.

Now, there's some tracts where we think there's less oil in place, there's some tracts where we think there's more.

But that resulting change is reflected on the next-to-last column on the right-hand side, the change from Exxon's calculations, thousands of stock tank barrels -- thousand stock tank barrels of oil, and we list them going down the page.

And of course, the big one is the change to tract 1709 where the FV3 wellbore is, and we have the significant difference on the pick at the bottom of the Upper Cherry.

The rest of the tracts have corresponding changes with them, but none of them are nearly as significant as that one.

Q. You've taken Mr. Hanson's hydrocarbon pore volume map, you've looked at the contouring, you have then arithmetically analyzed that and come up with an oil-in-place volume and shown the appropriate adjustment, then, to make?

A. That's correct.

Q. What do you do then?

A. Well, that number, that change in original oil in place, then, is carried through to the recovery of waterflood reserves and CO_2 reserves.

We assume that whatever recovery factor was used on that tract previously still applies, but it's -- The magnitude of the recovery is adjusted, based on the change in oil in place. If oil in place went up, obviously the recoverable reserves goes up. If oil in place goes down, recoverable reserves go down, but it's by the same factor.

Q. All right, sir. Continue with our discussion of this issue, then. If you'll turn, I think, to page 43, let's see how this is analyzed in terms of each tract.

A. Okay. Again, along the lines of the FV3, which is Tract 1709 in our Section 25, what I've done here is superimpose on an Exxon tract map, their Map 23, the report projected, primary recovery factors for each of the wells.

And again, I've taken remaining primary and added workover reserves to it -- those are both primary reserves -- and divided it by the oil in place. I wanted to see how the relationship of recovery factor varied around the field.

And what I saw was that the Premier tract, because of the problems that we've discussed, of course, had the lower recovery. It's got a .16-percent recovery of the original oil in place. If you look at the offset tracts, you know, they're much higher, and you have to question why.

But it looked to me that the -- obviously, the Premier tract was low. We knew why. The zone that was open in the oil well was in all likelihood producing some extraneous water. There was additional pay in the Lower Cherry, and there was additional pay in the -- I'm sorry, there was additional pay in the Upper Cherry, with our new correlation, and there was additional pay that was not opened in the Lower Cherry-Upper Brushy.

It's important to know that these recoveries, all of these wells, are going to be opened up in multiple zones.

For instance, Tract 1311, up there to the northwest, where they're predicting a 6.33-percent recovery of the original oil in place, that well will produce, once it's worked over, from both zones. So it's going to get 6 percent of the oil in place, but it's open in two zones. The Premier well, the FV3, so far has only produced from the Upper Cherry. It has not been opened up in all the zones yet.

But looking at this, I made an estimate based on the performance of the offset wells that a reasonable recovery for the FV3 under primary producing conditions would be a minimum of 2 percent of the original oil in place. To the east, we've got 2.6 percent, north and south, we've got much higher recoveries. But I wanted to have a number to come up with remaining Primary reserves for this well, and I estimated that it would be 2 percent of the original oil in place.

Q. All right, sir. Then what happens?

A. Well, if we look at page 44, it shows the results of going through that calculation. And again, I just list some tracts that are offset to 1709, the original oil in place on those tracts, the predicted primary recovery for each of them and the recovery factor, and you can see they're all above the 2 percent that we're predicting for the 1709 with the FV3 well.

But we have predicted -- 2-percent recovery of that would result in a calculation of 62,000 stock tank barrels of oil as ultimate primary recovery. And since we've produced 5000 there's 57,000 remaining. So the 62,000 barrels of oil represents 2 percent of the oil in place. And then we just subtract out what we've already produced.

Q. All right, sir. Then what happens?

A. Well, we've made the adjustment for original oil in place, we've determined what we think are primary recoverable reserves on this tract.

The next thing that we felt it would be important to do is to look at the flood patterns themselves that are proposed for the CO_2 flood.

Q. Let's do that. If you'll turn to page 45, describe what you're illustrating here.

A. Okay. Around the periphery of the unit, we do not have the wells in place at this time. Those are wells that are going to have to be drilled at some point in the future.

In the report, we've made the assumption that all of those wells will be drilled in the center of the tract. Well, there's nothing that makes us do that. We have the ability to move those wells wherever we want to move them within that tract. In fact, that was the basis for making the change between G-19 and G-24, was, they moved the injection wells, moved the producers around, and adjusted reserves on each of the tracts.

Well, the point that we're making here is that we don't have to drill these wells in the center. We can move them over to an orthodox position, 330 away from the unit boundary. And we make this adjustment not just on the Premier tract but all the way around the unit.

Q. Why would that be important?

A. Well, it's extremely important because in the modeling work that is done, when we do the quarter-acre pattern modeling, there is no oil available outside the quarter pattern for the well to produce.

Q. That's the assumption the model makes?

A. That's the assumption the model makes, that's exactly right.

And it's sort of the same thing that we do here with these flood factors. We're essentially establishing a no-flow boundary -- in this case we'll say on the western edge of the well, we've got the injector on the eastern side, and we make the assumption that the -- the report makes the assumption that no barrels are produced from the west side of that well.

And the reason that's important is, again, the formula considers only future reserves. The edge tracts don't get any contribution for the oil in place on the west side -- or the outside of the unit. It's a function of the modeling, because in the model the oil is not there for it to produce. But in real life it is.

We know that on the periphery of these wells, that there is going to be some oil drawn into the wellbore. It's a fact of putting the well on production. But for the purpose of calculating reserves, that outside production was not allowed to happen. And so the reserves that we have predicted totally ignore any of the oil in place outside, on the periphery of these wells. And that oil in place is actually there. Some of it will be produced, but it does not get credited to the tract that it comes from.

Q. When we look at the top illustration, that's what Exxon's doing to three of Premier's tracts when we see the volumetric -- I mean the volume geometric factors on Exxon's Exhibit E-7 --

A. That's correct.

Q. -- that's what they're doing here in the engineering book?

A. That's correct.

Q. All right. And by moving that well farther west, the producer farther west, you now have afforded the opportunity to that tract to recover 25 more percent of the recoverable oil within that tract?

A. That's right, it actually -- Instead of the flood factor in the top diagram, being .5, with the injector on the edge and the producer in the middle, only half the tract processed, Exxon assigns it a flood factor of .5. It only gives credit for half the oil.

In the bottom diagram, if we move the producer to the farthest orthodox location, we probably need to move the injector over with it, but we can increase the flood factor to .75. We process three-fourths of the tract, not just half of it.

And it's the same point that Yates was making yesterday about their concern of Premier leaving the unit. If the Premier tracts are not included in the unit, this flood factor percentage gets shifted over to the Yates tracts, and their oil in place gets cut by half, their reserves get cut, in the scenario where there is not a co-op. If there is a co-op, then those reserves get recovered.

But it's -- this scenario is what happens to Yates if Premier is removed, and that's probably why they're so interested in having Premier in the unit.

But eventually -- You have to draw the boundary somewhere, but we feel like the hydrocarbon pore volume maps show that there is definitely recoverable oil, not only in the tracts that are in the unit, but outside that. And this formula gives absolutely no credit to the oil on the exterior of the flood pattern.

Q. You're talking about Exxon's formula?

A. I'm sorry, Exxon's formula, you're right.

Q. In order to solve that problem, you're suggesting that if the Premier tract is included in the unit, that those producing wells, instead of being centered in each 40-acre tract, are required to be drilled 330 off their western boundary of those 40-acre tracts? Is that what I'm understanding?

A. I'm saying that we have that ability. We have the ability to do that. And the problem with the formula as it is right now is that it assumes that we don't, and it assumes that we leave those barrels in the ground. That's the problem with the formula, based strictly on reserves.

Whereas our formula, that has a 50-percent component for original oil in place, gives the tract credit for that oil that is between the producer and the edge of the tract. It also has the 50-percent weighting factor on production, so it recognizes the fact that an edge tract does not have the same value as an interior tract. But it does not ignore the oil in place on the outside of these edge tracts.

Q. This provides an option as to three of Premier's tracts. Do you have a suggestion for the Tract 1109, which is the one -- under the weighting factor has only 25 percent under Exxon's analysis?

A. That's right, if we look at page 46, the next page in the booklet, this represents Tract 1109, the most northwest corner tract in the unit.

Again, we're not -- The well is not there yet. We don't have to drill it in the center of the tract.

I'm in agreement with Mr. Hanson as he testified this morning that, you know, where's the really interesting part of the pay outside this unit? It's to the west and to the northwest.

Well, there's no reason in 1109 to have to put that well in the center of the tract. We can move it further northwest and instead of having a flood factor of .25 for that tract, we can double it to .5.

And it -- Again, this top diagram is another good way to talk about the modeling that was done. If you look at that dashed line, that does represent the model grid, the top picture on page 46, where we have a producer on one corner and an injector in the other corner. The only difference is that in the model, none of the other oil on that tract is contained in the model, whereas obviously in real life it is. But it's not in the model.

Q. Let's turn to page 47 and show you the effect of the revised flood patterns.

A. Okay. We've made this adjustment to all of the periphery tracts where the reserves -- where the wells are not currently in place. Obviously on Tract 1709, the FV3 well, that well is drilled and it cannot be moved. So we couldn't make any adjustment for that well. But every peripheral well where we could move it, we moved it out like we showed on the previous diagram.

And we show the flood factor from the Exxon report is in column 2 and the CO_2 reserves attributed to that tract, and then we show the proposed or adjusted flood factor, if we move the wells out as far as we can, and we use the factor of the two flood factors to raise the CO_2 reserves.

For instance, Tract 1109, previously we would have a flood factor of .25 and recover 265,000 barrels of oil. Well, under our proposal it would have a flood factor of .5 and it would recover twice as much oil, or 530,000 barrels.

Then we follow the same analogy for each of the tracts, where we have the ability to move the well location.

Q. Let's go to the reservoir pressure example --

A. Okay.

Q. -- you've got illustrated on page 48 and have you set up the example and lead us through it.

A. We just -- We wanted to show in a schematic form here that when you put a well on production, absent an injector on one side and an injector on the other, there's not a no-flow boundary at that well. The well is going to produce from all the way around, from 36 degrees around the wellbore.

Again, if you take an edge-tract well, although it does produce from all parts of its tract, it does not get any credit for the production that comes from the outside of the well.

So this was just a schematic to demonstrate that point.

Q. All right, sir, page 49, would you identify and describe what you're showing here?

A. Okay, page 49 is the last of our exhibits, and what we've done here is using our proposed formula that we had on the previous exhibit, we've gone back in and made the adjustments that we feel are necessary to the geology and to the reserve calculations for the various tracts.

And, you know, we obviously had -- we had different original oil in place. The January, 1993, oil rate, of course, is a factual number; that didn't change. Remaining primary reserves, we increased for the Premier well. Waterflood reserves are shown here. CO_2 reserves were increased, based on the flood factors. And then future barrels produced also went up because of the adjustments that we discussed.

If you use those numbers and use the formula that we have recommended, the bottom line shows the participation factors that would be applied to each of the various operators' tracts. And again, there's reasonable comparison between the two, reasonable agreement.

If we look at the future-barrels-produced line, the very bottom line, Premier actually produces 5.2 percent of the future barrels from the unit, but only gets 4.5-percent participation. Exxon produces 58 percent of the future barrels, gets the same participation. Yates produces about 36.7 percent of the future barrels and gets 36.1-percent participation. And similar for MWJ, similar agreement there.

Another important factor that I didn't bring up about the proposed formula is that two of the factors -- the January, 1993, oil rate and the waterflood reserves -- Premier still has zero value for those numbers, even though there is waterflood recoverable oil on their tract. And obviously the January, 1993, rates, the well was shut in, so...

Q. So the assumption is that the pattern as proposed by Exxon goes forward for the waterflood?

A. That's correct.

Q. And therefore the recoverable waterflood reserves that might otherwise be produced from the Premier tract are left unrecovered if that plan is initiated --

A. That's correct.

Q. -- the Exxon plan is initiated?

A. Well, they ultimately are produced under CO_2.

Q. And that's where you pick them up under this analysis?

A. That's correct. This formula takes the issue of timing away. It doesn't matter if the reserves are produced under waterflood or under CO_2, and we saw the problems that that presented on an earlier exhibit. It can throw the factor way off of line.

Q. Summarize for us your conclusions and recommendations, Mr. Payne.

A. I think that the formula, that it stands now, does not treat Tract 6, the Premier tract, in a fair and equitable manner. It does not reflect that tract's relative value to the unit.

And we have two options. Number one is to remove it from the unit. Number two is, if we're going to leave it in, we need to treat it fairly. And our formula that we have proposed not only treats the Premier acreage fairly, but we've shown that it treats everyone else fairly as well.

So it's a little bit unusual that we don't come with a recommendation; we're leaving two choices. But those are the two choices.

Q. If you'll take page 49 and compare it to 41, let's talk about the effect of the change. You're looking at page 41. Under 41 is the application of your recommended formula using these traditional parameters, by adopting Exxon's geologic conclusions?

A. That's correct.

Q. And at the bottom row of this spreadsheet, you've got various percentages assigned to the operators of those tracts.

Let's take that and compare it to the last row on page 49. If the Commission adopts Mr. Hanson's geology, and also adopts your proposed formula, what happens?

A. Well, there's really not much difference, obviously, since our big disagreement on geology affects the Premier tracts. It is primarily the Premier tracts that benefit. There is a difference -- We go from 3.4-percent participation, with our proposed formula and Exxon's geology, to a 4.5-percent participation with our formula and our geology.

Q. The impact on the Exxon-operated tracts is what?

A. Exxon goes from 59.2-percent participation down to 58.2. So really, the 1 percent switches from one to the other. There's, as you can see, minimal impact on Yates and minimal impact on MWJ.

Q. If the Commission adopts your formula and Mr. Hanson's geology, under the proposed participation factor for Premier, they would receive 4.52 percent of all future production?

A. Yes.

Q. Their share of the future barrels produced, which was a key component for you, if I understand correctly, for their tracts is 5.17?

A. That's correct.

Q. All right. Is that still fair and appropriate, in your opinion?

A. It's -- In my opinion, it is. It's -- The 4.5 percent is still in good agreement with all the average numbers that we looked at. When we make the changes in geology, it goes up to 4.5 percent, but it's still -- is in good general agreement with the future barrels produced, it sure is.

Q. All right. Let's finally look at this comparison. Let's compare the Exxon geology and formula to what happens to the Premier-Exxon-Yates tracts, as well as MWJ, and see what those percentages are in relation to the percentages you've shown on page 41, where it's your formula and still Exxon's geology.

A. Okay.

Q. Can you draw that comparison for us?

A. Yeah. We need to go back to page 32.

Q. And that's in your book, right?

A. In my book. We should have put a table together on this. I'm sorry we didn't do that, but...

If we look at page 32, the formula assigned participation for each of the operators is shown in the middle column. And where Premier, as it stands now, participates at 1.02 percent, if you contrast that to our page 49, our ultimate recommendation, they now get 4.5 percent.

Exxon under the current proposal -- and again, I'm comparing page 32 to page 49 -- Exxon, as it stands now, gets 64.8 percent; they get 58.3 under our formula. Yates currently has 34.07; they would stand to participate at 36.1 percent. And MWJ would go from .12 up to 1.08.

MR. KELLAHIN: That concludes my examination of Mr. Payne. We move the introduction of his Exhibit Number 9.

Have I got that wrong again? Is this 9 or 10?

MR. BRUCE: This is 9.

MR. KELLAHIN: All right, 9, please.

CHAIRMAN LEMAY: Without objection, Exhibit 9 will be entered into the record.

Mr. Bruce?

CROSS-EXAMINATION

BY MR. BRUCE:

Q. I'll try go to through the things in the order you did, Mr. Payne.

A. Good, we'll be organized.

Q. The first two pages of your Exhibit 9, I think, were aimed at saying why the unit boundaries should be different than they are, if I can paraphrase you. Is that correct?

A. Yes.

Q. Now, looking at page 2 of Exhibit 9, doesn't it appear that basically all the mapped area within, say, a six-foot contour line is within that unit?

A. There's good general agreement, as I think I stated, on the Lower Cherry-Upper Brushy. However, there's significant variation on the Upper Cherry.

Q. And that's what you tried to exhibit on page 1?

A. That's correct.

Q. In determining unit boundaries, would it be fair to take into account actual production?

A. It is a component, it's something to consider. It's not the only thing to look at.

Q. Well, let's look at page 3, then. And I understand the purpose of this exhibit, but you have a well -- the westernmost well on this exhibit, you show is producing from the Lower Brushy Canyon. Isn't if a fact that that well immediately to the east was dry in the Delaware?

A. I don't know the depth that that well was drilled to, and I don't know what was done to actually define it as dry.

Q. Okay, let's move on to page 4, page 4 of Exhibit

9.

A. I do know that we show significant hydrocarbon pore volume at that location in the Exxon maps and in our maps.

Q. Once again, when you say "operator", you're not talking about a particular working interest owner's total percentages here; you're just looking at their operated acreage; is that correct?

A. That's correct, and I hope that's clear. I know that's confusing, but that's exactly what I've done.

Q. But then you use the term "waterflood target reserves" out of the Exxon report. Isn't that actually waterflood target oil? Doesn't "reserves" imply an economically recoverable oil?

A. There's different definitions for reserves. Some of them are not economically recoverable at the current time.

But you're right, that is waterflood target oil. I didn't mean to confuse you by putting "reserves" there.

Q. And it would be the same on page 6? That's not reserves, that was the waterflood target oil?

A. That's -- You're right, you're exactly right.

Q. Or, excuse me, CO_2.

A. Yeah, as we've talked about, there's many different categories for reserves. But that is a total volume of the target. You would not recover all those barrels, under that process.

Q. Now, as I understand it, what you are advocating is, if Premier's acreage remains in the unit, you are also talking about significantly expanding the waterflood program to incorporate a number of additional producing wells and a number of additional injection wells for the waterflood program itself?

A. No.

Q. You're going to retain the same waterflood project area and the same number of injection wells and the same number of producing wells?

A. I have made no prediction of what Exxon would do with the waterflood. In fact, the waterflood AFE states that the pattern may be expanded, it may stay the same, it may be contracted, based on the results of the study.

What I am saying is that there is waterflood target oil on the Premier tracts. There is no difference, from a reservoir quality standpoint, between the Premier tracts and some tracts that Exxon does propose to waterflood.

And the point -- If you're talking specifically about page 8, is that the timing of whether or not you do it is critical. If the barrels are recovered under the waterflood process, they're much more valuable to the tract than if they're recovered under the CO_2 process. And by value, I mean as it is weighted in the Exxon formula. The Exxon formula weights it 50 percent to 25 percent for CO_2.

Q. But if additional wells aren't drilled on, say, Premier's acreage, or even some of Exxon's fringe acreage, those additional waterflood reserves that you speak about won't be recovered, will they, unless they go to a CO_2 program?

A. Yeah. Now, I am not saying that -- I'm not proposing that they waterflood the tract. What I'm saying is that this formula is biased towards the tracts where they do waterflood, as opposed to tracts where they don't. The beauty of our proposed formula is that it doesn't matter if they waterflood that tract or not.

So this exhibit is not meant to say that they should waterflood those tracts. It points out the problem when they don't.

Q. And you haven't done any economics with just expanding the waterflood program?

A. I have made some preliminary calculations on what it would be -- what the economics would be if you saw a similar recovery to some of the other Exxon tracts. And if you use a similar type recovery to what some of the Exxon wells are going to get on similar acreage, it's -- certainly you don't rule it out from an economic standpoint.

Q. But if you don't get the same recovery, then it doesn't work; is that --

A. Well, if you don't get the same recovery on the Exxon acreage, it's not going to work either. That's a given.

But the point is that from a reservoir engineering standpoint, there's no difference in some of the portions of the field that we are deciding to waterflood and some of the portions of the field that we are electing not to waterflood. But the formula has a strong bias towards the acreage that you do elect to waterflood.

Q. If you'll move to page 32 of your Exhibit 9 -- One preliminary question: Is this using the Exxon figures or Mr. Hanson's figures?

A. This exhibit is just using the Exxon figures, all the way up to the exhibit of our proposed formula.

Q. Okay.

A. Just so that everybody's clear, I think that's page 41. Everything prior to 41 is using Exxon numbers.

Q. Now, this percentage of future production, that's for Premier 3.3 percent. That's waterflood plus CO_2?

A. All Exxon assigns to Premier is CO_2 reserves, so that's all CO_2.

Q. Okay. And then the Exxon and Yates figures would include waterflood plus CO_2?

A. Plus workover, plus primary.

Q. Okay. So you're assuming that -- Is it just as likely as the CO_2 oil will be recovered, as the waterflood oil or the primary oil?

A. The analysis that we've done at this point in time would say that it's just as likely. We haven't done any more analysis on the CO_2 than we have on the waterflood.

Q. Does the CO_2 have a higher risk and cost than the waterflood?

A. A higher risk?

Q. Risk and cost than waterflood oil?

A. I don't know that the risk is any different than the waterflood. The CO_2 does have a higher cost. And by "risk" -- When I talk about "risk", I talk about the typical definition of reserve risk.

Q. One question on the Parkway-Delaware formula. That didn't have a CO_2 reserve component, did it?

A. I don't think that that was anticipated for that time. But again, the Parkway-Delaware, their formula was recoverable oil in the future. So it didn't have a bias towards workovers or waterflood or CO_2. It was just recoverable oil.

Q. Now, I think I heard you give a total recovery factor -- and I -- I guess it doesn't really matter which, whether you use Mr. Hanson's geology or Mr. Cantrell's, but a total recovery factor of 20 percent. That would include CO_2, waterflood workovers, primary, for this pool. Is that what you stated?

A. Yeah, and I -- I think the number is 22 percent, something like that.

Q. Twenty-two percent.

A. But that's ultimate recovery from the field --

Q. Okay.

A. -- which is just over 50 million barrels, divided by the oil in place, the 241.8, I think is what it is, from the Exxon report.

Q. Okay. What is this primary plus waterflood, roughly? You can calculate it if you want.

A. About 4 percent.

Q. Okay. So looking at your participation formula, 50 percent of it is based on original oil in place; is that correct?

A. That's correct.

Q. So 50 percent of your formula is that 78 to 96 percent of the oil that will never be recovered?

A. I missed that question. Can you repeat that question?

Q. Okay. Your formula is weighted 50 percent to original oil in place. But the recovery of that original oil in place will only be somewhere in the range of 4 to 22 percent?

A. Right.

Q. So let's assume it's almost all going to be recovered, say 80 percent -- 20 percent, let's say the total recovery from this pool is 20 percent. Fifty percent of your formula depends on the 80 percent of the oil that stays in the ground; is that correct?

A. No. No, 50 percent of the formula depends on the original oil in place, not the oil that stays in the ground.

Q. And 80 percent of that original oil in place will remain in the ground?

A. Well, we don't -- we don't -- We don't know that. But original oil in place is a traditional number that's probably in 90 to 95 percent of the formulas. And again, it's a factor, it gives a consistent uniform treatment to every tract on the field, every tract in the unit. And it --

Q. That would assume equal recoveries on fringe tracts as there are in the sweet spot of the field?

A. No, it does not, and that's why original oil in place is often used, is that it gives value even to tracts where you are not predicting as much recovery. It -- In this formula as it stands today, the 25-50-25, there is a ring of oil outside all of the producers that, from our predictions, is -- in the modeling work, is impossible to recover, and that oil is given no credit, no weight at all in the existing formula.

But the --

Q. And then another factor in your formula is 20 percent of future production, and once again, that 20 percent assumes that all of that tertiary oil is going to be recovered?

A. Yes, it does. The --

Q. And tertiary oil dwarfs the CO_2 and the water- -- I mean the waterflood and the primary oil?

A. Yes, it does. But the rationale was that the original oil in place is a well known, consistent number that's used in almost -- some form, remaining oil or original oil in place -- is used in almost all participation formulas.

The January, 1993, rate is a factual number. There's no argument about that. In fact, that's one where Premier gets zeroed out because they had no rate at the time.

The 20-percent remaining primary, that's really the lowest risk reserves. Even though we showed some problems, it's the lowest risk reserve prediction.

And then 20 percent for total future barrels to give tracts that are going to produce waterflood and CO_2 reserves, some value under that participation also.

But it's a consistent formula, it's a reasonable formula, it's very similar to the Parkway-Delaware formula. And the important thing to look at is that it gives an equal, or very close to equal, participation to the relative value of each tract.

Q. Let's look at the final page of your exhibit, page 49. I think you said you were here yesterday and listened to all the witnesses?

A. Yes.

Q. We can pull out the exhibits if necessary, but Mr. Thomas testified yesterday that of the Exxon acreage, Exxon was 100-percent working interest owner, and of the Yates acreage it owned about 25 percent of the working interest.

So correct me if I'm wrong. If you do that, that leads to Exxon having a gross interest in production of -- You can calculate it, but 58.3 percent? I mean --

A. I think it's --

Q. -- 67.3 percent, excuse me.

A. Yeah, that adds up.

Q. Okay. But then you've got to net out the royalty and overriding royalty interest owners. And we could look at the unit agreement, Exhibit B to the unit agreement. But assuming there was a burden on each lease of 17.5 percent, what would that make Exxon's participation in the unit?

A. Are you asking what 17.5 percent of --

Q. What's 82.5 percent of --

A. Of 67.3?

Q. Yes.

A. 55.5.

Q. So that's what you're recommending, that Exxon go down in participation from 74 percent to a little over 55 percent in this unit?

A. I'm recommending that Exxon get 58.3 percent of the oil produced from the future unit. What Exxon's royalty situation is on overrides, I don't have any control over.

What I'm concerned about is Exxon's share of the future oil production, relative to the other tracts in the field. And when I say Exxon, it's because you questioned me on Exxon. I'm concerned about MWJ, just as much as Yates, just as much as Exxon or Premier.

Q. Was there anything wrong with the numbers that I gave you?

A. I don't know. You told me to assume the royalties, so I don't know.

Q. Somewhere in there, though, Exxon's net revenue interest in the unit will be decreased from about 74 to 55 percent, roughly?

A. Well, yeah, assuming your royalty numbers are right, that's true.

Q. Yeah.

A. I think it's important to look, that even under Exxon's own calculations they've got 59 percent of the oil in place, they've got 59 percent of the wells, they've got 58 percent of the acreage, 41 percent of the waterflood target, 56 percent of the CO_2 target.

So even a factored, watered-down NRI number is in line with numbers that are traditional average values for unitization. We could argue all day, but I think it's fair and provides relative value.

Q. Okay. And Exxon has what? 75, 80 percent of primary production, current production?

A. They have 74.6 percent of the cumulative oil production as of 1-1-93. As of January, 1993, they had 79 percent of the rate.

And that 80-percent factor is one of the numbers we chose for the formula because Exxon needed, in my opinion, to have a little bit more value than some of the other formulas we looked at. So that January, 1993, rate was one we threw in there.

Q. Okay. And on the other hand, you're recommending for Premier 4.5 percent, which had 0.1 percent of primary production?

A. That's right. Premier had one well on one of their tracts that had serious mechanical problems, that we talked about.

And that just is another reason why in a factor, people oftentimes use three or four different things to look at, because if you look at any single value per formula, it can distort the picture. But if you look at an average of a number of things and then pick a few that provide good relative value, you end up with a formula like we had here.

Q. One final thing. How come you changed your participation formula on Wednesday, this Wednesday, from the participation formula you proposed on Monday?

A. Because it hurt Yates too much in comparison to Exxon. It gave Yates only a 30-percent participation. Once we incorporated all of the geologic work and the reserve work --

Q. What was --

A. -- we saw that that formula was out of balance.

Q. What was Premier's participation under Monday's formula?

A. It was higher. I don't remember the exact number, but it was higher.

Q. What about Exxon's participation under the Monday formula?

A. By addition, I guess it was probably higher.

MR. BRUCE: Okay. Pass the witness, Mr. Chairman.

CHAIRMAN LEMAY: Mr. Carr?

MR. CARR: I have no questions.

MR. KELLAHIN: Nor I, Mr. Chairman.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. I'll ask you the same question I asked the geologist. What is the current price for drilling, completing and perfing of a Delaware well these days?

A. I think that the AFE -- and we could look at it to be sure, but I think it's about $250,000. Now, they're doing a package, they get a little bit better price. But I think it's about a quarter of a million dollars.

I entertain anybody to look at the AFE, if that's not right. It should have the right answer.

Q. When you were talking about the risk factors of 75 percent and 95 percent, don't those risk factors assume that there's a good wellbore to be used?

A. The 95-percent risk is from proved producing reserves, and that is part of the risk. You don't give it a 100-percent value for the reserves, because it could fail at some point in the future. But statistics have shown in the past that 95 percent of those reserves are going to be recovered.

And it -- You sometimes need to factor in, is it a brand-new well that you think is going to have a 30-year life, or is it a well that has a 30-year life but it's in year 29?

So it's 95 percent on an average, but there are other factors that go into it.

Q. Or is it a well that has channeling behind the cement and all of the problems that were brought out --

A. That could potentially --

Q. -- in earlier testimony?

A. I'm sorry. That could potentially increase the risk, it sure could.

If you're doing an evaluation of a well, an economic evaluation, you might have a mechanical risk factor. And in that situation, it might be higher.

So I would consider that specific situation, if you know it to exist, more of a mechanical risk than a reserve risk.

Q. Negotiations concerning formulas have been going on for quite some time. When was the first that Premier gave an alternate formula?

A. I don't know that. We were contacted by Ken and Tom probably in October. It was November before I really got through all the data and --

Q. Last month?

A. Right. -- and told them that we felt like we could help them.

So it took us roughly about a month to come up with the formula. I think it took Yates and Exxon about three years. It took us about a month. But that's the only time frame that we were involved in the project.

Q. The revised flood patterns that you are suggesting, what impact will that have on the time involved for pressuring up that pressure, the CO_2 miscibility?

A. Well, I confused the issue. The wells that we recommend moving are the peripheral CO_2 wells. They're not involved in the waterflood at all. The reservoir will be repressured during the waterflood stage.

The only point that we're making there is that those wells don't have to be drilled in the center of the tract. They can be moved on the edge and capture more reserves. There will be less oil left in the ground.

But those are all CO_2 wells. That's why the flood factors were only increased on the CO_2 reserves.

That's the only wells that we've moving, are the CO_2 capture wells.

Q. And moving those wells would not have any impact on the time involved for instituting a CO_2 flood?

A. No. No, the waterflood will have already -- once we reach the -- I'm assuming once we reach the decision to do the CO_2 flood we will have seen the effect of the waterflood, we will have studied it, we will have known the reservoir is floodable, the reservoir will be above minimum miscibility pressure. And at that point we'll go to another vote and decide to do the CO_2 flood.

But at that point -- our only -- Our contention is that at that point, when we decide to do CO_2 , we're free to put the wellbores wherever we want.

And I said we would only move the producers, but we'd probably also move the injectors to be an equal distance between the two producers. So you might move them a little bit also.

COMMISSIONER BAILEY: That's all I have.

CHAIRMAN LEMAY: Commissioner Weiss?

COMMISSIONER WEISS: Yeah, I have a couple.

EXAMINATION

BY COMMISSIONER WEISS:

Q. You mentioned -- Yesterday we heard that Exxon estimated it cost the maybe $500,000 to perform a study of this. What do you think it would cost your firm to do such a study?

A. It would depend on how detailed. We did a lot of logs, a lot of log analysis, geologic interpretation. We probably wouldn't do the quarter pattern modeling; we'd probably want to do more of a full-field model if we were going to really try to predict what's going to happen. I'm going to run away potential clients. It could be several hundred thousand dollars. I think we could do it for less than Exxon spent, but it would be a lot of money.

And that's why one of my first decisions was, do we start over or can we fix this?

Q. And as I understood it from your answer to Commissioner Bailey, your input to this thing was last month?

A. I was reviewing the work that had been done and talking back and forth with Ken for the month before. But our input, as far as designing a new formula, was primarily over the last month.

Q. Do you think it would have had more effect if it had been brought up in 1994 or 1993?

A. Let me make sure I understand --

Q. Do you think your input would have -- Obviously they didn't pay much attention to you, or you wouldn't be here today.

Would they have paid attention to you back in 1993 or 1994 if you had been involved in this unitization process as it went along, rather than coming in a month ago?

A. I haven't had any negotiations with Exxon or with Yates, and I should probably apologize for taking out the formula so late. They got it the day after I got it, after I saw what we needed to do.

I would like to think that if we had been involved, we could have impressed upon everybody that this formula, as it is, is not fair. And I certainly would like to think that Exxon would have listened, and Yates and MWJ.

I said before, we have done work for Exxon in the past. I would like to think they would listen.

Q. And now in the course of your review, did you -- and you mentioned you had worked on the Parkway-Delaware waterflood. Did you come across any waterflood analogies in the Delaware? Did you evaluate any?

A. I think the Parkway is the best analogy. It's probably similar size, scale, scope. I can't think of any others that I would consider to be a good analogy.

Q. How is it working?

A. We have lost touch with it a little bit, but I have had discussions with a geologist who was a working interest owner in the unit, who tells me that it's going very well, that they are very pleased. Now, I don't know if that helps you, but they're happy.

Q. Yeah, uh-huh.

A. I don't have any numbers.

Q. That's fine. You mentioned something about pressure on your graph or your picture here to show how pressure declines offsetting the producer, the pressure drawdown --

A. Page 48?

Q. Yeah. What's the current pressure on Tract 6, current bottomhole pressure?

A. I don't know of a pressure measurement. I do know that there's been very little reservoir voidage on that tract.

The Upper Brushy-Lower Cherry -- I'm sorry, the Lower Cherry-Upper Brushy has never been produced on any of that tract.

There's been a -- some production in FV3, in the upper part of the Upper Cherry. There's never been any production in what we consider the lower part of the Upper Cherry.

It's a long way of saying I don't know, but it's not much below virgin pressure, I wouldn't think, on that tract, unless we have very good communication with the offset tracts that could have potentially drained or reduced the pressure.

Q. Let me see, and then without a waterflood or a CO_2 flood, how much oil do you think will be recovered off of Tract 6?

A. That's a very good question. I should have covered that, because that's another thing we look at as far as do we want to be in or not?

I did look at the offset recoveries of the tracts offsetting the Premier acreage. We're 1109. I looked at 1111, 1113 -- sorry, 1311, 1511, 1711.

And if you look on page 43, if you look at the recovery factors, under primary conditions that are predicted for those tracts, the 4.5, the 6.3, the 5.08 and the 2.57, again on the tracts just east of ours --

Q. What about to the south? Did you figure that one?

A. I didn't figure that one because it wasn't in the report. This data was just coming from the Exxon report.

But if you assume -- And again, we're talking about tracts with similar porosity, similar water saturation. If you assume those same recoveries of original oil in place and apply it to the oil in place on the Premier tracts, in 1109 you get 152,000 barrels; in 1309 you get 235,000; 1509 is 181,000; and 1709 is 80,000 barrels. So the total is 648,000.

Now, the reason I calculated that is, I was wanting to compare it to how many barrels the formula credits Premier's tracts with, and that's 489,000 barrels. So it looked to me by analogy these tracts under primary conditions alone could potentially produce 650,000 barrels if they did just what Exxon said they were going to do next door. So that's 160,000 barrels difference, and that --

Q. Well, what's the bird in the hand?

A. You have to consider that, and the question is the FV3. It was not drilled to be a Delaware well.

Q. Well, was the one to the south drilled properly, completed properly?

A. I don't know the mechanical situation of that well like I do the FV3, but I know it was not drilled as a Delaware well. It was drilled to go deeper, at a time when we did not know the problems associated with drilling through the Delaware.

So that would only lead me to speculate, and I shouldn't do that. I just don't know about that well.

COMMISSIONER WEISS: That's all my questions. Thank you.

THE WITNESS: Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Just a couple, Mr. Payne, since the word "fair" has been used a number of times. You don't think the formula is fair. Is that --

A. No, sir.

Q. -- your "fair" or Mr. -- Yates' "fair" or Exxon's "fair" or -- can you -- Let's figure the word "fair". It's been raised a number of times. We need a definition of it.

Do you want to revert back, if you would, to that -- where you listed all those formulas. I think that must be Number 41, page 41.

A. Page 41.

Q. Yeah. Have you been involved in negotiations with other -- representing companies when they're -- like Parkway, when they're working on a formula for unitization?

A. We have, our firm has, I personally have. We, a lot of times, don't get involved in formula negotiation. We are hired to do a study, to determine whether or not the project is feasible, and we typically let the working interest owners discuss the formula. We give them a sheet like this and say, you guys go decide what's fair.

Q. So generally there, the formula ends up being a product of negotiation. Or does everyone agree what's fair?

A. I don't know if everyone always agrees what's fair. I think there's compromise sometimes. And I think sometimes when you can't agree, you end up in this forum here. So no, we don't always agree.

Q. Do you know any examples where a regulatory body has set the formula on a unit agreement?

A. We were involved in a situation over here recently where the formula was addressed, and rather than change the formula, changes were made in the geology and the reserves. So I do know that the NMOCD here just recently has been involved in a situation like this, and that was the one Mr. Kellahin mentioned yesterday, the West Lovington-Strawn field.

Q. But the formula stayed in, it's just the science changed, didn't it?

A. The formula stayed in, the science changed, that's correct.

CHAIRMAN LEMAY: The -- I'm not sure if that one's reached -- That wasn't appealed, was it?

MR. KELLAHIN: No. Small point: Mr. Payne testified at that hearing and proposed a formula --

CHAIRMAN LEMAY: Uh-huh.

MR. KELLAHIN: -- and it was rejected by --

CHAIRMAN LEMAY: Yeah, that period of time for appeal of that order, I don't think -- I haven't seen --

THE WITNESS: I don't think it's going to be appealed.

CHAIRMAN LEMAY: I don't think it's been

appealed, is my point.

MR. KELLAHIN: The parties settled between the two processes and kissed and made up.

CHAIRMAN LEMAY: Yeah.

MR. BRUCE: Mr. Chairman, Mr. Kellahin and I were both involved in that, and it wasn't appealed, of course. And that one -- The two main working interest owners, Charles Gillespie and Dalen resources, own 90 percent of the working interest between them, and the change that was adopted by the Commission added two percent to that working interest. So they had very little incentive to appeal.

Q. (By Chairman LeMay) Yeah, I was trying to get into a point of how these formulas are arrived at, and I just wondered. Since Mr. Payne was using the word "fair" and has mentioned some formulas, I just wanted to go into that a little more, how these things are arrived at generally.

A. I can tell you that I've been in meetings when working interest owners arrived at a formula in less than 15 minutes, and I've seen situations where it takes years. So I don't know if there is a --

Q. Are they negotiated, then, generally, even 15 minutes, or is it just --

A. They -- Yeah, I guess you would use the word "negotiated", and they arrive at something that is fair.

Q. And fair, okay.

A. Let me say that I think this is a benchmark field. We do have the Parkway Delaware in the area, but this is a field that hopefully is going to work under waterflood, hopefully is going to work under CO_2.

And I think the next time we have one of these they're going to be asking, What did you do in the Avalon? And it's something for you to consider seriously, as I know you will, and I think that this formula is a better way to do it.

Q. Didn't you say Parkway had no CO_2 component?

A. It was based purely on recoverable oil, and to the best of my recollection that did not include CO_2.

Q. Because the reserves here, I mean, the oil in place and what's been talked of reserves, the CO_2 just overbalances everything else.

A. Yeah --

Q. To me, it appears that -- if you look at the numbers --

A. You're exactly right, and that's why we're not too concerned about them not waterflooding the tract. I mean, otherwise that would be a much bigger issue.

But the -- we have things -- At the April, 1994, working interest owner meeting, there was a handout. We didn't pass it out. But according to Exxon the prize is the CO_2 project. You know, the reserves for the waterflood -- if you risk those reserves at an appropriate risk factor and do a risk analysis of the waterflood, you might not do it. You might not do it.

Exxon's probably got better places to spend their money. If you -- You know, we're looking at the potential of CO_2 here.

Q. And you mentioned it again, page 41. What I wanted to ask is, you list 13 factors there, and depending on how you weight those factors I assume one party may consider it fair -- Example, it doesn't take a PhD in mathematics to look at that third one. Oil production of the second one, cumulative oil, if you weight those heavy, or weight them at all, that reduces, and we've -- all the formulas we've seen increases Premier's participation.

But if you weigh heavily a cumulative oil factor that's going to reduce your participation, isn't it?

A. It would. That's why I said I think there are two tests. What -- How are the future barrels produced from each tract compensated for in the formula? This compensates for them. And also, what could a tract do on its own? And we see that the Exxon formula falls short on that.

So I think those are the two tests. And we've tried to come up with a formula that gives a reasonable, fair treatment to each tract.

CHAIRMAN LEMAY: Thank you.

THE WITNESS: Thank you.

CHAIRMAN LEMAY: Commissioner Weiss has another one.

THE WITNESS: Okay.

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. One more question, pretty basic. How important is a CO_2 flood to Mr. Jones --

A. I don't --

Q. -- in your estimation?

A. I don't know if I could answer that. I think it's --

MR. KELLAHIN: May I suggest that if the Commissioner would like to recall Mr. Jones, let's put that question to him.

COMMISSIONER WEISS: You bet, he can speak right there if you don't mind.

THE WITNESS: Well, I think --

MR. KELLAHIN: Speak up, Ken.

MR. JONES: Excuse my cold. I think in three years it's something that's -- after the CO_2 tests are done, it's going to be a reasonable thing to look at, at that time.

But right now it's not. And as we got testimony -- we -- You know, the potential primary behind our tracts is there. Is it --

COMMISSIONER WEISS: So my question was, CO_2 flooding is not important to you?

MR. JONES: I think it could be very important in the future, in three or four years.

COMMISSIONER WEISS: Thank you.

THE WITNESS (MR. PAYNE): Can I say, from a reservoir-engineering standpoint and an oil-recovery standpoint, it's obviously very important.

COMMISSIONER WEISS: Thank you.

CHAIRMAN LEMAY: Additional questions of the witness? If not, he may be excused.

Are we --

MR. BRUCE: I would ask permission to put up Mr. Cantrell for about five minutes of rebuttal.

CHAIRMAN LEMAY: Okay.

MR. CARR: May it please the Commission, I would also like to call Dr. Boneau.

CHAIRMAN LEMAY: Okay, let's take about five minutes.

(Thereupon, a recess was taken at 2:45 p.m.)

(The following proceedings had at 2:57 p.m.)

CHAIRMAN LEMAY: We'll resume.

Mr. Bruce?

MR. BRUCE: Mr. Chairman, if I could, I'd like to recall Mr. Cantrell, and I'd like the record to reflect he was previously sworn and qualified as an expert geologist.

CHAIRMAN LEMAY: Okay.

DAVID L. CANTRELL (Recalled),

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Cantrell, you've been here listening to Premier's witnesses, haven't you?

A. Yes, I have.

Q. And you heard some discussion about the FV3 well and the state of that well and whether or not it's damaged, haven't you?

A. Yes, I have.

Q. Let's get on to that. Could you identify your Exhibit 40 and discuss what that shows for the Commission?

A. Okay, Exhibit 40 is a production plot from the well we keep discussing here, the Eddy FV State Number 3, the FV3 well, and it simply shows rate versus time for oil production, for water production, and then a third one for water cut. The oil rate is shown in green, the green line there. The blue line indicates the water production. The red line shows water cut.

Just quite simply, this exhibit is meant to kind of indicate the production history of this well. The yellow box in the front end of this plot indicates the early time history of this well, when they were doing quite a lot of testing of the well, just to give you some more detailed information about how it was making -- about the kind of rates it was making.

You can see that the well first came on line at the end of April, early May, 1984, and declined out through time. Last reported production that I have records of is April, 1986. The total production from this well is 5.1 thousand barrels of oil.

This is just to show you kind of the history of the well. This is quite a typical production plot, two-rate decline for Avalon wells.

Q. So the production decline before the workover is normal for an Avalon well?

A. Yes, yes.

Q. Okay. And does this also show that after the workover the water production rate declined?

A. Yeah. I should point out that there was -- in the yellow inset box, the early time portion of this well, there was another recomplete attempt above the Downlap surface, which ultimately produced no oil, but it did interrupt oil production through that time.

Oil production before and after that recomplete attempt was basically similar. Water rates are basically similar. In fact, through time, if you look at the long-term history of this well, water rate has basically declined through time.

Q. Is there any evidence of the Upper Cherry Canyon workover causing any problems with this well?

A. I see no evidence of that recomplete causing a problem.

Q. Are there any well reports that might have been filed with the Division or elsewhere that indicated there were any problems with this well?

A. Not to my knowledge.

Q. What's Exhibit 41?

A. Exhibit 41, then, is a comparison of the production history -- and this time we're just looking at oil rate -- of the FV State Number 3 with its nearest offset to the south, the Citadel ZG1 production.

This well -- We all agree that the FV3 and the ZG1 look fairly similar, are analogous geologically. What we're showing here is, then, an oil-rate-versus-cumulative-oil plot of the FV3 and the Citadel -- the ZG1 well there to the south. The ZG1 production is shown in green, and the FV3 production is shown in red, so that the red line on figure -- on Exhibit 41 is the same as the green line on Exhibit 40.

This exhibit was originally put together in June of 1995, quite a few months ago. Basically what it shows is that production from the ZG1 is on trend, is exactly -- or is very similar to the production behavior for the FV3.

Since this time, we've had some further production, and the ZG1 production trend is right along the same trend as the FV3 well.

So not only, then, are they analogous geologically -- I think we all agree on that -- but it appears that the production, the oil production from these two wells is pretty analogous also. The ZG1 doesn't appear to have any completion problems, as we've been informed the FV3 has.

I might also add that water rates for these two wells are also fairly similar.

Q. When you say informed about completion problems on the FV3, you're talking about the statements of Premier's witnesses?

A. Testimony I've heard today.

Q. Mr. Hanson, Premier's geologist, got up and discussed the mud log on the FV3 well. Do you agree with Mr. Hanson?

A. Well, not exactly.

Q. Okay, and could you discuss that? And I'd refer you to your Exhibit 42.

A. If you'll take a look at Exhibit Number 42, this is a depth plot, again for the Eddy FV State Number 3, the FV3 well, and it shows several of the raw wireline log curves that we used in the geological and volumetric modeling that we did, as well as some of the calculated parameters that we derived.

Just to kind of briefly describe this exhibit first off, the first track on the left is gamma ray. Next is the depth track. Within that depth track are annotated only the depths, but also on the right-hand side are the perforated intervals there.

The next track is resistivity. The track after that, as you go to the right, is effective -- is calculated water saturation. Finally, the track on the extreme right-hand corner of this exhibit is porosity.

What I've done, then, is using standard lagging techniques, I came up with a little different answer than Mr. Hanson did. I ended up lagging the show up about 11 feet from its drill depth location. And I've annotated where I would put those shows on this, and you can see it drawn in red there, on -- I guess it's the fourth depth track over, fourth track over.

And you can see in the sort of overall gross interval in question here, there's really two major and maybe another subsidiary mud-log show there. When you log it the way that I've done here, you can see it fits in quite nicely with the other information that we have available.

For example, if you compare it to the water saturations that you've calculated from the wireline logs, you can see that both of those areas of gas show fit in pretty well with low calculated water saturations. In fact, that upper mud log show fits in quite nicely with what turns out to be the highest oil saturation, the lowest water saturations that's calculated in the entire well.

Also, I should note on here, let me back up and say that it's hard to visualize, but there's -- Just above what's indicated as 2800 on the depth track, just above that there's a line with a very small typed "UCHB". That's the base of the Upper Cherry Canyon. Moving on up the depth track, 2700 and just above that is a line annotated "UCHM". And finally the next line annotated above that is the Upper Cherry Downlap. So the UCHB line is basically the base of the Upper Cherry.

The point here is, the way I would lag this show is to -- results in this mud-log show being entirely within the Upper Cherry Canyon interval. It corresponds quite well, then, with calculated water saturations.

If you'll note also, it corresponds also with the completion data. If you'll look over in the depth track, if you see the little open boxes there, those are the intervals that Gulf actually perforated. So clearly Gulf felt that this was probably the way this log should be lagged as well. So we feel this sort of scenario, this sort of technique, is probably correct.

These lower mud-log shows, they are definitely on the mud log, on this uncalibrated, unmanned mud-log show that Premier was talking about earlier. They -- Apparently Gulf again didn't feel they were worthy of testing, and apparently Premier doesn't either, since they've had the well for five years and haven't done anything about that.

Q. Now, Mr. Hanson submitted his Exhibits 5 and 5A, some raw data. Who provided that data to Premier?

A. I did.

Q. One final issue, Mr. Cantrell. When Dr. Jones was testifying, he mentioned that it looked like in certain of his wells there was -- there were other zones which may be productive in the Delaware on his acreage.

Outside of the two main pay zones that you discussed, I think in Exhibit 16 of your testimony, direct testimony, are there other productive zones in this pool?

A. The answer is yes. Locally there are other small, productive intervals around the area and even within the unitized area that we've proposed. There's a couple of generalizations you can make about all of them, though.

In particular, the one they're interested in is in the Lower Brushy Canyon. If you actually look at well-test information around the pool, the Lower Brushy Canyon has been tested at least 15 times. The maximum production, maximum cumulative production from any of these wells is less than 12,000 barrels of oil. The average of the successful tests was just under 8000 barrels of oil cumulative production from these zones.

Q. Are these zones continuous across the pool?

A. No, they're small, they're stratigraphically discontinuous and isolated, as much as 600 to 700 feet apart, vertically. So they would probably not be very good candidates for a waterflood or a CO_2 flood.

Q. Okay. Finally, let me show you -- This is Mr. Payne's Exhibit 9, just the very first page. It's actually, I think, Mr. Hanson's geologic map.

When he was discussing unit outline, down toward the southwest corner of the unit -- I can't tell exactly; it looks like there's a well in the -- What would that be? The northwest quarter of the southwest quarter of Section 36?

A. Okay.

Q. And it looks like it has a dryhole mark. What is that well?

A. Yeah, that well is a well operated by MWJ. It's the GW State Number 2 well. This well TD'd -- It was drilled as a Delaware test. It TD'd at the top of the Bone Spring, and it was a dryhole.

MR. BRUCE: Thank you, Mr. Cantrell.

At this time, Mr. Chairman, I would move the admission of Exxon's Exhibits 40 through 42.

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

Mr. Carr?

MR. CARR: I have no questions.

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. When we're looking at these hydrocarbon pore volume maps that you prepared, Mr. Cantrell, you were discussing with Mr. Bruce the EP Number 2 well, which is -- I'm sorry, that's the EP3. The EP3 is the one on the northern boundary --

A. I'm sorry, could I --

Q. -- of the unit?

A. -- could I get a map?

Q. Are you with me?

A. Uh-huh.
Q. Up north of the EP7, which is the Yates well in 1111 --
A. Uh-huh.
Q. -- outside of the unit is the EP3.
A. Yes. Mr. Bruce and I weren't talking about that well; we were talking about the GW2 well.
Q. All right. When you look at the EP3 well --
A. Okay.
Q. -- on this display --
A. Correct.
Q. -- that's given hydrocarbon pore volume thickness in the Upper Cherry Canyon that is outside the current northern boundary of that proposed unit, is it not?
A. That's right, that's right.
Q. Do you know what it produces out of currently?
A. It produces out of the Lower Brushy.
Q. Do you have any idea what the cum is on that well?
A. It's about 30,000 barrels.
Q. How does that relate to this 12,000 or 8000 criteria in terms of production?
A. The 12,000 barrels of oil is the largest cumulative production from the Lower Brushy Canyon inside the interval.

Q. Yet outside the unit on that boundary --

A. That's --

Q. -- we've got great production?

A. That's correct. In fact, if you look over at the GW1, there are other wells around that produce from this zone. But they're generally different -- They're different from what we're talking about flooding.

Q. All right.

A. They're isolated. The GW1 is separated from the main pay by the GW2 which is a dryhole.

Q. Within the unit area, then, for the Delaware formation, that is getting unitized?

A. That's correct.

Q. You're subjecting the flood to what? Everything? What reservoirs are to be flooded?

A. We are subjecting -- The intervals we're proposing to flood are the main pay zones. These are the zones that contain the vast bulk of the reserves. That was the point of my earlier comments.

Q. All right. Are you suggesting to the Commission that there is absolutely no value for any of the other zones within the unitized interval?

A. The point of my comments was to indicate to the Commission that yes, there is other production around. But is it economically viable? Especially, is it something that you would want to go after for a waterflood or CO_2 flood?

Q. I've not made myself clear, Mr. Cantrell. Within the unit --

A. Uh-huh.

Q. -- you've got existing wellbores. Those wellbores and that log information gives you the opportunity for oil recovery outside of the reservoirs being credited within the Exxon book?

A. If there is current production or cumulative production from other wells, I mean, that's given credit.

Q. I guess my point is, and I think you and I are agreeing, the formula ignores all those other zones in determining value.

A. What it ignores is -- What it says is that those other zones are not good candidates for waterflooding or CO_2 flooding. They're not good candidates in terms of their discontinuity, in terms of their reserves, in terms of the oil volume that they contain.

Q. Yeah, that's not in the formula? The formula makes assessments of risk and weighted factors based upon the Upper Cherry Canyon and this Upper Brushy Canyon. It makes no judgment about any other zone?

A. I'm not an expert on the formula. I'm just trying to simply tell you which zones are good candidates for waterflooding and which zones aren't.

Q. The judgment was made by Exxon that in the formula in terms of deriving relative value to use only the Upper Cherry Canyon as we've discussed and this Upper Brushy Canyon, that's it?

A. That's correct.

Q. All right. You discussed in Exhibit 40 this FV3 well. Is it your responsibility to make decisions about water channeling and workover potential of wells?

A. No, the whole point of this, Mr. Kellahin -- I'm not an expert on frac height or any of that sort of thing. The whole point of this was just to show you what this well has actually done.

Q. All right, we're talking engineering --

A. We're talking production. We're not talking engineering or geology --

Q. Well, let's --

A. -- we're talking production data.

Q. Let's talk about geology in terms of the water. Does Exxon have cores of this Upper Cherry Canyon interval?

A. Yes, it does.

Q. What did you calculate to be the R_w for the Upper Cherry Canyon?

A. It's in the report. The value is like .04 or something like that.

Q. Exhibit 40 --
A. Yes, sir.
Q. -- it's got color codes on here. We've got a water rate. Okay? We've got an oil rate down here. The water cut is in red, is it not?
A. That's right.
Q. And what's the scale used to position that water cut on the display?
A. Well, that's the scale shown on the display. In other words, water cut from the beginning is very high, very close to 100 percent.
Q. And how were you able to plot that water cut as demonstrated on Exhibit 40?
A. I'm sorry, I don't --
Q. Where did the data come from to get the water cut to put on here?
A. It was calculated.
Q. All right, and then the plot represents what, sir? The water cut over time?
A. The plot represents the oil rate over time, the water rate over time, and those are direct measurements. And then calculated from those two, you can calculate a water cut.
Q. Did you calculate this water cut?
A. Well, yes.

Q. You're the one that put the red line on here?
A. Well, I didn't physically draw that --
Q. No, sir, but your work product resulted in that line being drawn on this display?
A. Yes.
MR. KELLAHIN: All right. No further questions, Mr. Chairman.
CHAIRMAN LEMAY: Questions, Commissioner Bailey?
Commissioner Weiss?
COMMISSIONER WEISS: No questions.
CHAIRMAN LEMAY: I have no none. Thank you.
THE WITNESS: Thank you.
MR. BRUCE: I have nothing further, Mr. Chairman.
MR. KELLAHIN: A little housekeeping chore, Mr. Chairman, while we wait for Mr. Carr to recall Dr. Boneau.
I have neglected to introduce two exhibits for the record.
Exhibit 10 is Mr. Payne's temperature survey, which he discussed in association with his engineering book. We would move the introduction of Exhibit 10.
In addition, I have taken Mr. Hanson's hand drawing, where he described and illustrated his geologic discussion, and marked that as Premier Exhibit 11. We would request your permission to have those admitted formally into the record at this time.

CHAIRMAN LEMAY: Okay, those exhibits will be admitted into the record. Thank you, Mr. Kellahin.

Mr. Carr?

MR. CARR: May it please the Commission, at this time I would like to recall Dr. Boneau and request that the record reflect Dr. Boneau remains under oath and that his credentials as a reservoir engineer have been accepted and made a matter of record.

CHAIRMAN LEMAY: Fine, so noted.

DAVID F. BONEAU (Recalled),

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Dr. Boneau, you were present when Ms. Bailey asked Mr. Payne questions about the impact of relocating certain wells during the CO_2 flood of this project, were you not?

A. Yes, sir.

Q. Her questions were directed at the impact of relocating these wells on the timing of implementation of CO_2. In your opinion, will moving these wells have other impacts on the CO_2 flood in the Avalon-Delaware Pool?

A. Yes, and I hope that I could demonstrate that in a brief period of time. The essential point is, there is no free lunch. You don't get something for nothing by moving those wells out. I'll attempt to draw this situation.

I'm attempting to draw the four Premier tracts and the adjacent four Yates tracts, a part of the reservoir, to try to illustrate the idea. And the wells that exist, four Yates wells -- and the Premier well is about here.

What Exxon is proposing is -- and this is in the CO_2 stage -- is to drill an injector here and drill a producer on the Premier acreage, roughly there. And you will not recover any of this oil out to the west.

What Premier suggests is moving these wells, this edge well, closer to the boundary and thereby accessing the oil in this 330-foot strip between the Exxon-proposed location and the Premier-proposed location, and then at the same time moving this injector west. And what he actually showed was so that the relative distance between the injector and producer out in the Premier acreage would be similar. Now, he maybe isn't tied to that, but you would move this injector west in order to access this well. Fine.

But what happens, and what he didn't go into, whatever, what he didn't go into was that you hurt the situation over here. You've moved this injector further away from the Yates producers, and the result of that is that you're going to get a less efficient recovery in here, on the Yates Acreage, in order to get more recovery on the Premier acreage. You're just going to be -- Your sweep efficiency is the word the engineer would use, but your sweep efficiency on the Yates acreage is going to be hurt, and that's where the free lunch goes away. And basically, that's the whole point.

Now, we're not going to go into numbers, but you do lose recovery on the Yates acreage in order to accomplish the things that Mr. Payne suggested in moving these wells out. And kind of hidden in his assumptions was that this efficiency on the Yates would remain the same, and in truth -- I'm sure everybody agrees that it won't.

Q. And Dr. Boneau, the area where you're going to have a less efficient sweep, is that not in a better portion of the reservoir than moving further to the west, further to the edge of the reservoir?

A. Yes, that's correct. The thickness and the production, et cetera, on the Yates acreage is superior to what's on Premier, so you're hurting your recovery in a better part of the reservoir in order to improve it on the edge.

Q. Now, Dr. Boneau, you were present, were you not, when Mr. Weiss asked Mr. Payne questions about his analogizing the potential for the Premier tract with offsetting wells east of the Premier tract, were you not?

A. Yes, I've been here.

Q. And also you were present when Mr. Weiss asked questions about the well due south of the FV Number 3 well, were you not?

A. Yes, I was here for that.

Q. The well due south of the FV Number 3, is that the Citadel ZG Number 1 well?

A. Yeah, that's the Yates well with that name.

Q. And to what formation was that well originally proposed?

A. That well was permitted as a Delaware well, and it was drilled as a Delaware well. When Yates reached the bottom of the Delaware, the logs were so discouraging that we deepened it a relatively short way into the Bone Spring and ran pipe and made a poor Bone Springs producer, which has since been recompleted back to a poor Delaware producer, like we said, but --

Q. How poor? How poor is the well in the Delaware?

A. The well is now making 7 oil and 200 water, and it has the production that you just saw from Mr. Cantrell.

Q. And this is the immediate south offset to the FV Number 3?

A. Yes, sir, that's correct.

MR. CARR: That's all I have.

CHAIRMAN LEMAY: Thank you.

Mr. Bruce? No questions?

MR. BRUCE: No, sir.

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: Just a few points, Mr. Chairman.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Dr. Boneau, for the well you've just described, I think I have found it in Tract 1711. I'm sorry, just a minute. Where is it? Oh, no, this is the 1909 well. You're looking at the -- I've lost track of my well numbers here. VG1, is it?

A. ZG1.

Q. ZG1.

A. ZG1.

Q. ZG1. What are your forecasts of what that well is going to recover?

A. Less than 20,000 barrels of oil. 10,000 to 15,000 barrels of oil.

Q. Okay. Under your analysis of what occurs in the CO_2 project, have you made an analysis of what happens under the waterflood process if the common boundary between Premier and Exxon is as I've indicated? Your existing wells, as shown, are there. Under the current waterflood plan, as I understand, everything to the west of those existing wellbores is not going to recover the waterflood target oil attributable to the Yates tracts within those four tracts; is that not true?

A. That's my understanding also, yes, sir.

Q. Are there waterflood target oil recoverable reserves in the west half of each of those tracts?

A. There are probably some. Not a whole bunch, but some.

MR. CARR: Thank you, Mr. Chairman, that's all I have.

CHAIRMAN LEMAY: Commissioner Bailey?

COMMISSIONER BAILEY: No questions.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, I have a question. It's concerning the unitization effort that's been put together to date. I guess you've been involved for a long time in it, and initially -- I don't know all the details. I haven't read your books carefully. But as I got it, Exxon came in with a formula that you disagreed with.

A. That's correct.

Q. You renegotiated for a year or two and finally got an agreement; is that correct?

A. We renegotiated for ten months, approximately.

Q. Ten months, and got an agreement.

How long will it take you to renegotiate again, or is there any assurance there will ever be a unit if you have to do it again, if we find we want to change the unitization formula?

A. Those renegotiations would not be trivial. They would take six months or two years or never happen. They will not take a week or a month. They will take -- They will take a significant length of time, and I'm not sure that I can yell and scream at those guys enough to get it straightened out.

COMMISSIONER WEISS: That's my only question. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Just a quick one, Dr. Boneau. Do you know if you drilled that -- What's the name of it? The CZ1?

A. ZG1.

Q. CG1.

A. ZG1.

Q. C -- Zebra?

A. It was intended -- Yeah, Zebra.

Q. Okay.

A. It was intended to be called Citadel --

Q. I see.

A. -- and when Yates submitted the papers they spelled it C-i-t-d-e-l, and so sometimes it's called Citadel and sometimes it's called Citdel and sometimes it's called ZG1 and sometimes it's just called that crummy well.

[Laughter)

Q. (By Chairman LeMay) Did you drill that crummy well with fresh water, mud?

A. I don't know for sure. I think the procedure is, you drill with fresh water, and you pick up enough salt out of the salt that you're really drilling with salt mud.

CHAIRMAN LEMAY: Only question I had. Thank you very much.

THE WITNESS: Thank you.

CHAIRMAN LEMAY: Does that conclude it?

MR. KELLAHIN: No, sir, I need to call Mr. Payne back --

CHAIRMAN LEMAY: Okay.

MR. KELLAHIN: -- to address a couple of points, if I may, Mr. Chairman.

CHAIRMAN LEMAY: Yeah.

MR. CARR: May it please the Commission, while Mr. Kellahin is calling Mr. Payne, I would like to mark and copy what Dr. Boneau drew as Yates Exhibit Number 8. I move its admission.

CHAIRMAN LEMAY: No crummy well on the exhibit?

MR. CARR: No crummy well on the exhibit.

TERRY D. PAYNE (Recalled),

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Let's deal first, Mr. Payne, with Dr. Boneau's drawing, his concerns about the fact that if the CO_2 project is ever initiated, your notion that adjusting the producers farther west, relocating the injector is somehow going to have a hidden adverse consequence which you have not addressed or recognized.

A. Okay. The first thing we need to do is look back at Exhibit 28, that Exxon presented. The reason that I made the assumption, if you will, that you get nothing for nothing is that they are all irregular patterns in this field, and Exxon makes that assumption in their calculations. Their flood factors are .5 or .75; they're not .53 or .68.

So the only reason I made that assumption is that we're free to move those wells, and those patterns would be no more irregular than the patterns that are already going to be in the field. So I just wanted to clear that up.

And I feel like that our estimates of CO_2

reserves are reliable as they are.

Q. Mr. Cantrell raised or sponsored Exxon Exhibit 40, I believe it was, where he was discussing some engineering issues with regards to water cuts and what that well could have or would have or should have done. Do you have a copy of that display in front of you?

A. Yes.

Q. What does this mean to you as an engineer?

A. It's very important. It's the issue of the whole projection mechanism of their model.

The FV3, as they have it plotted here on Exhibit 40, clearly shows a rapid decline in oil rate at the initial production period of the well. It shows a corresponding increase in water cut.

This is not a water-drive field. The only way the water cut is going to increase is if you get extraneous water production.

This exhibit clearly shows that there's a channel in this well, and that's why the water cut is increasing.

Q. And you have to take out those factors in the formula, or the adjustments or decisions Exxon made on the FV3 well, in order to get an appropriate value for that tract?

A. That's right. And if you -- Further, if you look at Exhibit 41, you see the initial oil rate of the FV3 is over 60 barrels a day, and it quickly drops to below 20. That's when the water comes in through the channel.

When you compare that to the Citadel ZG1, there's no comparison as far as initial oil rate. So clearly you can see what's happened on this well.

MR. KELLAHIN: That concludes my examination, Mr. Chairman.

CHAIRMAN LEMAY: Questions of the witness?

MR. BRUCE: No, sir.

CHAIRMAN LEMAY: Commissioners? None?

COMMISSIONER WEISS: No, I have no questions.

CHAIRMAN LEMAY: Okay. Thank you, you may be excused.

MR. BRUCE: One thing, Mr. Chairman. There's a couple of folks here from Unit Petroleum, and Mr. Ed Heald of Unit would like to make a brief statement, not testimony.

CHAIRMAN LEMAY: Well, that's fine. What I'd like to do, and we usually do this, is ask my fellow Commissioners if they want to recall any witness for any reason, to ask any questions.

I need to know first if that's the end of your --

MR. BRUCE: I have no --

CHAIRMAN LEMAY: -- of your all testimony, the witnesses you have.

Mr. Kellahin?

MR. KELLAHIN: We have concluded our evidentiary presentation.

CHAIRMAN LEMAY: Okay. Mr. Bruce.

Mr. Carr?

MR. CARR: Yes, we've concluded, Mr. Chairman.

CHAIRMAN LEMAY: Are you -- Do you want to recall anyone, Commissioner Bailey, ask any questions of any of the witnesses?

COMMISSIONER BAILEY: All the questions I had before have been answered.

CHAIRMAN LEMAY: Thank you.

Commissioner Weiss, any questions?

COMMISSIONER WEISS: No, I have no more questions.

CHAIRMAN LEMAY: I wanted to give you all the chance.

I don't have any either, so we're ready to wrap it up, if you want to -- your statements now?

MR. BRUCE: Yeah, Mr. Heald.

MR. HEALD: Yeah, I'm Ed Heald with the Unit Corporation.

CHAIRMAN LEMAY: I'm sorry, identify yourself again.

MR. HEALD: Ed Heald, Unit Petroleum.

MR. BRUCE: H-e-a-l-d.

MR. HEALD: I'm Ed Heald with the Unit Corporation. And as discussed previously, we're a small working interest with less than five percent of the unit.

And I guess basically as a statement, we'd like to say first, we're very impressed with Exxon's technical report. It's a very thorough, detailed -- and we -- I've looked at the geology, and we agree with the interpretation of Yates and Exxon.

And also, as a small working interest owner we feel that we've treated fairly and equitably by our working interest in the unit that's been proposed.

And also make a statement that even as a small working interest owner, Exxon has been very good to get us all the information that we needed to help evaluate the proposed waterflood, and we're very appreciative of that also.

That's all.

CHAIRMAN LEMAY: Thank you very much.

Additional statements for the record?

Do you all want to summarize briefly?

MR. KELLAHIN: What's the flight schedule?

MR. BEUHLER: We missed it.

MR. KELLAHIN: Did you?

CHAIRMAN LEMAY: I mean, that's up to you.

MR. BRUCE: I have a page-and-a-half statement I'd like to make. And in accord with Mr. Carr's rules of procedure, I believe I go last.

MR. KELLAHIN: Mr. Carr, what are the procedures? Would you like to make a statement?

MR. CARR: I'd be happy to make a statement, and I'll go whenever you tell me to. I mean, I will give my statement.

MR. KELLAHIN: Mr. Chairman, members of the Commission, I think it's the practice of the Opponents to close first, and then let the Applicants have the last say, and the parties supporting their position. I believe that is the practice.

CHAIRMAN LEMAY: That's fine. You all have that worked out. We're here to listen.

MR. KELLAHIN: All right. What I'd like to recommend to you is that the Commission afford us the opportunity to submit to you proposed decisions in the form of orders and findings with regards to the topics of importance from our perspective, and we hope that you'll afford us that opportunity.

CHAIRMAN LEMAY: Mr. Kellahin, I plan to ask for draft orders from all parties.

MR. KELLAHIN: Let me preface my statements by telling you I have looked and searched to see if Mr. Bruce, Mr. Carr or I or anyone else has brought to this Commission this kind of case for decision. To the best of my knowledge, you're establishing a precedent with whatever you do in this case. This is a case of first impression for this Commission under the Statutory Unitization Act.

Commissioner Weiss expressed a question yesterday with regards to whether or not anybody had done this before and what did you do? The simple answer is, the absence of those cases is attributable to the fact that in most situations the big boys buy out the little boys and the little boys go away.

Occasionally, the Division Examiners will deal with the statutory unitization procedure, which is available only for waterflood projects and only for tertiary projects. Normally, they will deal with them, because there's parties that they cannot find. That will occur.

You will find that there's a majority of the working interest owners that have selected a solution for which there is some disagreement, and during the course of that process, before the case reaches you, it is compromised, settled or otherwise disappears.

The closest analogy I have for you is a recent case that Mr. Bruce and I did for Larry Squires of Snyder Ranches on my part. He was a small royalty owner in one of

Gillespie's tracts. Gillespie was the operator seeking the waterflood. It was a pressure maintenance project -- it was gas injection, is what it amounted to -- to increase oil production.

Gillespie and others had consolidated all of -- or a substantial portion of the working interest ownership. The Division correctly allowed us to debate, discuss the geology, the distribution of reservoir pore volume and to consider and rule upon an appropriate selection of participation parameters, as well as a formula.

I will suggest that order to you as a starting point in your deliberations, because Examiner Catanach has created one of the finest crafted decisions that I think this Division has made. It is well reasoned, it's well articulated. Unfortunately, I didn't win although I wanted to win, and neither did Mr. Bruce. But that's not the point. I think he has fairly framed the issue, and he reached a decision based upon the record he heard.

What he did, and what I suggest to you, is, he struggled with fairness. The Chairman has asked what's fair. Fair means -- a moving target, perhaps. You have the benefit of the statute. The State of New Mexico, through the legislative process, has defined fairness for you, and I'm going to show you that definition.

This is the fairness formula. Let me outline for you how I have analyzed it, and that is, I've taken out of the Statutory Unitization Act these components where the Legislature defines fairness.

One of the issues of fairness is a decision with regards to the size and the shape of the unit. You must first of all make a decision with regards to how many tracts are in this unit and what shape it takes.

Mr. Payne is correct in understanding that it's very common for the technical people to present you a hydrocarbon pore volume map with a zero line, and we see either voluntary unitization or statutory unitization done within the framework of a zero line to define the limits of that reservoir, and so that everyone included in that package is treated on some technical basis that is fair. That is generally what is done.

If you'll see, however, down in the bottom of the summary I've given you, under Section 70-7-7, in sub A, it says, the Division -- and that means the Commission as well -- has the authority and the obligation to approve or prescribe a plan or unit agreement for unit operations which includes an entire pool or a part thereof.

And that makes sense. You have seen through the course of sitting in these kinds of proceedings, with regards to units, that it is not unusual to see a reservoir being developed with adjoining multiple units.

We have suggested to you an option that is viable, feasible and represents a solution for you in this case, and that is to exclude the Premier tract and afford the opportunity to Premier to make a judgment at such time in the future -- estimated it now to be three or four years -- in which to make the business decisions about participating or not in the CO_2 project.

That can be accomplished on a cooperative basis where those lease-line injection wells are done between the two properties. We've had cases before this Division where we've talked about lease-line injection wells.

I will tell you and represent to you that under statutory unitization, as well as your general scope of authority and power, this Commission can direct over Ken's objection the drilling and location of those injection wells along that boundary. If in three years they come back with their science project and give you the feasibility that shows it's practical to do so, then we can all make that decision then. And if you find that it is, then it will happen. You have that authority.

You've tested some of your authority recently when the Stevens case, the Exxon-Stevens case, went to the New Mexico Supreme Court. The lawyers here participated in that. Your powers are awesome, they're incredible.

The framework in which you get to do this has some limits, however. My position is, Exxon is piggy-backing a speculative CO_2 project on top of this waterflood project. I recommend to you that you have the authority and the obligation to separate those two projects. The problem of what they have presented to you is, they have given you a flawed proposal.

When we look at fairness under the definition of statutory unitization, it describes a relative value under 70-7-4-J. Relative value is a two-part concept. It's a contributing value, and it's a compensating value. It is inappropriate for you to include the Premier tract for the waterflood project, because it has no contributing value. Under Exxon's analysis, it zeroes out in those parameters.

The limitation of the Act says that you determine relative value as to each unit's relation to other tracts, taking into account those like-kind parameters. They have analyzed it, they've credited nothing of those recoverable waterflood target oil to the Premier tract, because the flood doesn't extend that far.

They are shifting the risk from Yates and putting it on Ken, and that's what's happened. Ken doesn't get to decide anything anymore.

You are Ken's trustee, his fiduciary for his share, at this point. The decision has been made. As a one-percent owner, there is no decision that he can now make, or in the future make, that matters.

If the CO_2 project goes forward, it's going to be decided by Exxon and by Yates. Ken's not going to decide anything that matters. The only thing he will do is either consent or go nonconsent. If he goes nonconsent, his interest is gobbled up with his share of whatever production is attributable to him.

You're in Ken's shoes, you get to vote today as to what happens to Ken's tract for the next 60 years, while Exxon and Yates get to postpone that decision till sometime in the future when they have determined the feasibility and the viability of the CO_2 project.

Mr. Bruce and Mr. Carr are likely to argue that Ken never drilled a well on this fringe tract. We don't know what's going to happen. Simply because that never has happened is no excuse to drill the producing well, not to expose it to waterflood and to hold it in their inventory for three or four years until they make the business decision about whether it goes forward.

The fact that Ken did not sell his interest to Exxon, that that didn't happen, is a problem here, because you're seeing this case within the context of a case of first impression. The precedent you establish will determine how other cases like this are handled.

You have the authority. It says -- Under Section

70-7-6-B it says, If the Division or the Commission determines the participation formula, does not allocate unitized hydrocarbons on a fair, reasonable, equitable basis, if you believe Mr. Payne's testimony, then it says the Commission shall -- it doesn't say you may or you might or you ought to -- it says you shall determine relative value.

We're suggesting the solution to that is to adopt Mr. Payne's recommended formula by which, as you see from his conclusions, all interest owners under the operated tracts have an increased advantage under his formula, with the exception of some of the Exxon tracts which are slightly reduced. I think there was a three-percent shift.

My point is, you have that authority. It is your obligation under the statute to resolve a dispute that the parties have not been able to solve for themselves.

When you look at the first section, which is probably the most important, you're looking at a section that describes establishing fairness, based upon a proportion that the quality of recoverable oil or gas in a given tract bears to the total property within the unit.

The Exxon proposal does not do that. It is fatally flawed when it apportions like-kind reserves under that weighted formula. It is no excuse to compensate Ken for one percent of remaining primary production, when he is making no contributing value for that category. It is my opinion and belief under this statute that you're precluded and limited from doing so.

And so how do you resolve it?

You either accept Mr. Hanson's geology, adopt his reservoir pore volume, and require the parties to put that into the calculation. That is one solution that we've discussed for some time, that is an option for you.

You have the option of excluding Ken's tract. We've discussed that. You know perhaps better than anybody at this point that that's a choice for you.

You have the option and, I suggest to you, the obligation to change the formula.

The threat from Exxon and Yates is that if you tinker with the deal, they're going away, this ain't going to happen. I think that's nonsense. I think that's nonsense, that those two big boys are going to take their toys and walk away from this deal if one percent says, I don't want to be in it and you come up with a solution that's fair to everyone. Exxon and Yates are going to walk away from this deal? I would think they would have better business integrity and more responsibility than to abandon this project, based upon the decision you make with regards to Ken's one percent.

You have a dilemma, a scientific dilemma. You've got to come to grips with the net pay thickness in the FV3. Mr. Hanson's described for you that problem. You have to make a decision on that issue. We will leave it to you to decide what to do. The consequences are apparent. The formula -- The distribution of pore volume changes if you believe Mr. Hanson.

We believe the CO_2 project is premature. Do you want to loan money on that CO_2 project? Is the bank going to loan money on that CO_2 project? You're the banker of this deal. You get to decide if this is important enough, if there's enough money and cost involved to require the big boys to come back here in a couple of years and tell you what they're doing, why they're doing, and get approval, then, to do what they think they might possibly do at some point in the future.

We're asking that you separate these projects, if you decide to approve them, that you approve them separately, or deal with them separately, and give Ken the opportunity to have the benefit of your best choice on what you will now do with his interest.

Thank you.

CHAIRMAN LEMAY: Mr. Carr?

MR. CARR: May it please the Commission, it's interesting to be here today for Yates, with Premier looking at us as one of the big guys and Exxon looking at us as one of the little guys.

But we're here today because after an effort that has taken the better part of five years, we are at a point where we believe we have an important project to present to you, to support Exxon in presenting it to you.

And we are here in a case that, like all cases, will set some precedent. But this is an important case, because this is really the prototype for a number of Delaware units that, if we are successful here, will be coming before you over the next few years. The project itself is very important, and the benefits will accrue to Yates, to Exxon, to Premier and to numerous other parties in the industry.

One thing I think is very clear in this case, and that is that no one disputes that Exxon is and has been the proper party to bring this proposal forward. They have the technical and financial ability to go forward with this project, not only today but as it goes forward through the secondary recovery phase and into the CO_2 flood.

And the CO_2 flood is very important. It may not be important to each of the players today, but the reservoir engineers tell you that it is a central issue in the long-term development of these Delaware reservoirs, it's terribly important.

And it is not only important but it is prudent to look at that today, to address that, and to recognize that that is a legitimate and an appropriate factor as we go forward, trying to determine how to best develop the remaining reserves in this pool.

The evidence before you, I think, clearly shows that if you approve Exxon's proposal, the benefits to all the parties are great indeed. Obviously, they are great to Exxon's, to Yates. And we submit on the evidence before you they're very great for Premier as well.

We will tell you that denial of the Application, or even modification of the formula, is a tremendous setback to the effort, and there may be no project at all.

And while Mr. Kellahin says, Oh, goodness, the integrity, I think these people have more integrity than to stand before you and tell you that they won't be back if this doesn't work, I think you need to weigh that comment in view of the fact -- in view of Dr. Boneau's testimony that shows for years and years we've worked technical reports, voting procedures, allocation provisions, and it is because of the integrity of Yates and the integrity of Exxon and those who decided to get in and play and work on this, other than just in a tangential way, that we're here before you at all. That's why we're here.

And if you change the formula and say start over, there is no assurance that this project will ever be back.

Now, this case may be unique in some respects -- they all are -- but you are again called upon to decide the issues before you, based on waste and correlative-rights considerations. And that's not unique. And you're called upon to decide this case based on the evidence presented here in this proceeding. And that is not unique.

And the waste consideration and the waste issue, I submit, is fairly simple. Yates and Exxon come before you and say, Without the Premier tract, as we go forward with the development of this reservoir, 2 million barrels of oil can be lost. That's the waste issue.

We believe that more will be recovered with them in. And if you agree with that, then we submit you should rule for Exxon.

We've had an engineering presentation by Premier, which is interesting. It says you can take us out and it won't change anything. But the assumption is that you will get the same production or the same recovery from each tract. Well, you can do lots of things if you use that as a threshold assumption. You can change the boundary any way you want.

We submit, though, that what we have shown is that if we go forward over the long haul and we go through secondary and tertiary recovery, this tract must be in. And with it in, more production in fact will be recovered from the project area.

As to the correlative-rights issue, we have two geological interpretations that have to be addressed.

Yates and Exxon concur in the Exxon presentation. Premier takes a different interpretation, and Mr. Hanson came in here today and he talked to you about that interpretation. He did, however, note that the Premier tract was on the edge of this reservoir.

And then he talked to you about the possibility of other productive zones, the possibility that the FV3 had been damaged when it was completed, that you could have water from other zones, that there was potential for additional production on a stand-alone basis.

But the fact of the matter is, we talked about what was possible, what might be done, what was the potential, but what they don't have is any proven production from their tract, any proven commercial production. Five and a half years we've been waiting for them to prove up something, and they have not. And I suspect it's not unfair to geologists present to state that there are geologists who have concluded that various formations are possibly productive, only to discover when you try and go out and complete them that they are not, that in fact they are not productive.

They haven't proven anything. They come here and argue from things that they are speculating can and might happen.

The engineering is also based on the word "potential". If we had thrown the word "potential" out of this hearing, we'd have been home in plenty of time to hear Oprah Winfrey this afternoon. But we didn't. We've heard what potentially can be done, what might occur. And for five and a half years nothing has been done.

And I will tell you that I'm not here to say there's nothing wrong with having no data. I'm here to say that after five years there are some consequences of having no data. I would suggest that's why you have a five-year state lease term, that if you sit on it for a long time you hit the point where if you haven't done anything, you get out of the way and you let those who are going to do something with the resource go forward.

We submit to you what we have come forward with does protect the correlative rights of Premier.

Now remember, correlative rights is defined as the opportunity to produce your fair share. But that does not mean you have an opportunity to prevent prudent development of a resource.

And when we talk about correlative rights in the context of statutory unitization, it's couched in slightly different terms, because here we have to look and determine and ask you to look and determine whether or not what we are proposing in terms of a formula is fair, reasonable and equitable to Premier.

Fair, a term that I guess is like pornography, the saying, you know, I know it when I see it. Well, I think you have to look at it in those terms.

And I think when you look at the formula here and you have a one-phase formula considering primary production, secondary production and then what will occur during the CO_2 flood, and you look and you see -- Premier has nothing in terms of remaining primary, they haven't been able to do it. They've been out testing their well, they can't return that well to economic producing posture, and ergo they have no secondary.

Their value comes in the CO_2 phase, and we've shown you we believe four percent of the production will be coming from their tract at that time. And we add zero and zero and four, and you weight it, and we come out with one percent.

And I submit to you that when you look at that, that should look fair, especially when you recognize that there are still substantial hurdles to overcome before we get to a CO_2 phase, when you recognize that they're going to have a cash flow today from a property that hasn't produced anything to speak of in the last five years. They get one percent today, I submit to you, for contributing absolutely nothing at all.

Now, Mr. Kellahin says I'm going to get up here and tell you, well, they didn't drill their well. And I'm going to tell you that Yates in fact drilled their well for them. It's that lousy well to the south, the Citadel or Citdel Number 1, that may accumulate 20,000 barrels if we're lucky.

And when you have a formula that will get this tract, if it goes through the CO_2 phase, approximately 500 barrels of oil, and the well that is most reflective of what can be done with that tract shows they would accumulate 20,000, yeah, that sounds fair to me. That doesn't sound like big players running over a little guy.

So we submit to you that what we have in fact is a proposal that protects their correlative rights.

Now, as to the formula, we've been in negotiations for months, and there are 40 owners that have been involved directly or indirectly. It was really only the day before yesterday that we got a formula from Premier.

Now, Mr. Weiss, I don't know how it would have played out if they had arrived and presented this data back at the time we were really thrashing out the formula, because it's very hard now to reconstruct that.

But it is also very hard to pay attention and consider these issues when there's no one showing up to present them in the first place.

If they had been there, perhaps we could have talked about these things and determined whether they were appropriate. But they weren't there, and that's just how it is.

And so what they have done is, the afternoon before hearing they have come in with a unilateral proposal, which credits them with reserves that they have failed to develop, and they come before you and argue again for a formula.

And even last time their own witness, Paul White, who -- the record of that has been incorporated into this proceeding -- Paul White said, you know, you can't -- you shouldn't consider on one of these formulas reserves that have not, in fact, been developed.

But what we have is, we have some expert witnesses who have worked for the last several months, they have looked for a number of factors that could be considered to value the property. Current rate is one, they say, original oil in place is another, cumulative production is one that they didn't actually consider.

And we see they have come up with the Premier formula. And their experts have selected factors which I would submit are very favorable to them, and I would have to congratulate Mr. Payne for doing his job. If you look through their book -- and you can move from page 32 to page 39, and you'll see that on page 32, well, their future production is 3.3 percent. By the time you massage those figures further on page 49, the Premier tract's going to contribute 5.1 percent. And yet they haven't proven any of it by producing any of it.

And then they come in and they say, Yes, well, we can move the wells around and we can catch additional oil. And they are then trying to capture things on their property which, according to their geologist, is out on the fringe. And they are creating a less effective development pattern in the better portions of the unit.

Basically what you've been asked to do is accept log data, accept that information over real production data.

And that's one of the reasons we have an Oil Commission. We have geologists and engineers who are asked to evaluate this and see if in fact in the real world that's the way to go, if what you ought to do is cast aside what's really happened and start chasing varying geological interpretations. And that's entrusted to you.

I will tell you that I think we stand before you in a somewhat different posture than Premier, because the material that we've presented to you goes back many years, and it's easy to take it and criticize it years down the road. But it was developed for the purpose of developing oil. It was for the purpose of prudently developing this reservoir.

And yet Premier stands before you with evidence which has been concocted in the last couple of months and a formula revised this week, and its purpose is to derail this effort, to stop it.

And I would suggest, when you factor that in, what we present is before you in a somewhat different and somewhat better posture.

We think the decision is simple. If you agree with us, if you believe that our efforts can in fact effectively, in the years to come, develop the remaining reserves in the Avalon-Delaware, if you believe that we really are serious about recovering the additional 2 million barrels of Yates acreage, then you should agree with Exxon and approve the project, because it prevents waste.

If you agree with us that 500,000 barrels of oil is better than the, what we believe, 20,000 barrels they could probably get is fair, if you believe giving them a cash flow now when they have none is fair, and if you believe going forward with this project and sharing the benefits with all the interest owners as we're proposing to do is fair, then correlative rights will be protected, and again you should rule for Exxon.

And in ruling for Exxon, I submit you not only meet your responsibilities under the Oil and Gas Act, but you also will find the formula fair and you will carry out your responsibilities under the Statutory Unitization Act as well.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Bruce?

MR. BRUCE: Mr. Chairman, as I said in my opening, we're here today after almost five years of effort to unitize this pool. During that period, an excellent technical report was prepared, the plan of unitization was agreed to by in excess of 98 percent of the working interest owners and royalty interest owners, and a unit is instituted which will recover, at a minimum, an extra 8.2 million barrels of oil for the benefit of the State of New Mexico.

These figures are based on geology which Exxon spent years developing, versus a couple of weeks that Premier has spent to object to this case.

The only dissenting party in the unit has been Premier. During the negotiation period there were several working interest owner meetings at which Premier was allowed to present its geological interpretation of the pool. Not one single other working interest owner agreed with Premier's geology, in large part because there's no production from its acreage to back up their interpretation.

Premier could have drilled a well to prove its claim. In fact, Paul White, Premier's former engineer, recommended just that in 1993. Premier didn't do so, even though -- I'm not sure of the drilling time for a Delaware well, but probably around ten days.

Actually, this refusal to drill is, in fact, reasonable. After all, no other single working interest owner has drilled a well in this pool since 1985, except the well drilled by Exxon in 1990, in the middle of the unit, to gather data for unitization. Obviously, no one thinks that the fringe tracts have primary production potential.

So Premier went to the June, 1995, Division hearing, and again no one believed its speculative geology. After the Order was entered by the Division, Premier decided it better do something. So it re-entered the FV3 well. What happened? Well, got a few barrels of oil per day, 300 barrels of water per day. It's an economic well that no one would produce for primary recovery. This re-entry verifies what Exxon and Yates have said for years about that tract and it validates the Exxon technical report.

Now Premier is back, and what does it rely on? Again, it relies on speculative geology, unverified by actual drilling and production. It certainly didn't rely on its October, 1995, well work. They were actually kind of offended that we brought that up.

So what does Premier do now? The day before the hearing it proposes a participation formula that no one has agreed to and which has no chance of being approved by the necessary number of working interest owners. I can state for a fact that Exxon will never approve it.

And why? Because the formula totally ignores actual production, and it also ignores the higher risk and cost of tertiary oil recovery. It also treats the fringe tracts as if they're in the heart of the unit. We think that's ridiculous.

If Premier's plan is adopted, this unit is not going to fly, and the stable will lose millions of barrels of oil.

There's been speculation about a potential lease-line agreement that may at some time, at some unspecified time, assist in the recovery of the 2 million barrels that Dr. Boneau talked about. But that's pure speculation. We don't think that will ever happen either. Such waste should not be condoned by the Commission.

Mr. Kellahin refers to correlative rights. Correlative rights enables a party to obtain recoverable oil under its tract. Actually, as Mr. Carr said, the opportunity to obtain recoverable oil under its tract. Premier has never taken that opportunity, number one.

But the other key word is "recoverable". Exxon has proven that Premier has no economically recoverable oil under its tract until a CO_2 flood is instituted. Nonetheless, the participation formula gives value to Premier's oil in the ground from day one, even if it's never produced. Thus, Premier's correlative rights are protected, allowing Premier to treat its tract as if it's in the sweet spot of the pool, when clearly that's not true, it is ridiculous.

Mr. Kellahin also referred to relative value. I think all you need to do to get a quick glimpse, a one-second glance at relative value, is to take out Exxon Exhibit Number 22, the production map, the bubble map. This clearly shows where the good part of the field is, and it gives a snapshot of relative value.

Based on that, based on the other factors set forth before you, Exxon and Yates proposed a formula, which gives everyone fair value in their tracts, and it's been overwhelmingly approved by the interest owners.

We simply urge the Commission to quickly issue an order affirming the Division's Order, which approved unitization.

Thank you.

CHAIRMAN LEMAY: Thank you. Anything else in the case?

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: Well, we -- a couple weeks -- with Christmas season, now, how about three weeks for draft orders? Is that pushing it?

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: Okay, we'll leave the record open for some draft orders by the various representative counsels.

And thank you very much for everyone's contribution, and hope you all have a very happy holiday season.

We'll take this case under advisement. See you all next year.

(Thereupon, these proceedings were concluded at 4:12 p.m.)

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CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL January 8th, 1996.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998