STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO

12 April 1989

EXAMINER HEARING

IN THE MATTER OF:

Application of Sun Exploration and Production Company for a waterflood project, Eddy County, New Mexico. — CASE 9646

BEFORE: Michael E. Stogner, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division:	Robert G. Stovall Attorney at Law Legal Counsel to the Division State Land Office Bldg. Santa Fe, New Mexico
For Sun Exploration and Production Company:	William F. Carr Attorney at Law CAMPBELL and BLACK, P. A. P. O. Box 2208 Santa Fe, New Mexico 87501
For J. C. Williamson	Chad Dickerson Attorney at Law DICKERSON, FISK & VANDIVER Seventh and Mahone/Suite E Artesia, New Mexico 88210

I N D E X

I N D E X Cont'd

E X H I B I T S

EXHIBITS Cont'd

MR. STOGNER: Okay, we'll call next Case Number 9646.

MR. STOVALL: Application of Sun Exploration and Production Company for a waterflood project, Eddy County, New Mexico.

MR. STOGNER: Call for appearances.

MR. CARR: May it please the Examiner, my name is William F. Carr, with the Santa Fe law firm Campbell & Black. We represent Sun Exploration and Production Company and we have two witnesses.

MR. STOGNER: Call for any additional appearances?

MR. DICKERSON: Mr. Examiner, I'm Chad Dickerson of Artesia, New Mexico, appearing on behalf of J. C. Williamson and I also have two witnesses.

MR. STOGNER: Are there any other appearances?

Will all the witnesses please stand at this time.

(Witnesses sworn.)

MR. CARR: David.

MR. STOGNER: Mr. Carr.

MR. CARR: At this time we call David Rojas.

DAVID R. ROJAS,

being called as a witness and being duly sworn upon his oath, testified as follows,to-wit:

DIRECT EXAMINATION

BY MR. CARR:

Q Will you state your full name and your place of residence, please?

A My name is David Raymond Rojas. I live in Midland, Texas.

Q Mr. Rojas, by whom are you employed and in what capacity?

A I'm employed by Sun Exploration and Production Company and I am a staff geologist.

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

A No, I have not.

Q Would you briefly review your educational background and then summarize your work experience for the examiner, please?

A I graduated from the University of Kansas in 1981 with a Bachelor of Science degree in geology. I proceeded to work for Sun Exploration and Production Company in Midland, Texas, working the Permian Basin from 1981 to 1985; then proceeded to work the Williston Basin out of Denver and Dallas for Sun Exploration and Production Company and for the last year have been working the Permian Basin again out of Midland, Texas, with Sun Exploration and Production Company.

Q And your current assignment, the area of responsibility covered thereby includes southeastern New Mexico?

A Yes, it does.

Q Are you familiar with the application filed by Sun in this case?

A Yes, I am.

Q Have you made a study of the area?

A I have.

Q And have you prepared certain exhibits for presentation in this proceeding here today?

A Yes, I have.

MR. CARR: We tender Mr. Rojas as an expert witness in petroleum geology.

MR. STOGNER: Are there any objections?

MR. DICKERSON: None.

MR. STOGNER: Mr. Rojas is so

qualified.

Q Mr. Rojas, will you state briefly what Sun seeks with this application?

A Sun seeks approval to initiate a pilot flood of the Williamson Sand.

Q The Williamson Sand is part of the Delaware formation?

A It is.

Q And you're going to be instituting a pilot secondary recovery project?

A Yes.

Q What well do you propose to use as an injection well?

A We propose to use the Mobil 22 Federal No. 5 Well.

Q Is this a new project as opposed to an expansion of an existing project?

A Yes.

Q Would you refer to what has been marked for identification as Sun Exhibit Number One and identify this exhibit for the examiner and then review the various things that are shown on this exhibit?

A Okay. Exhibit Number One is a structure map on top of the Williamson Sand. It is also included on this exhibit a type log, being that of Mobil 22

Federal No. 5. This type log shows the entire Delaware Sand group which is composed of the Bell Canyon Sand, the Cherry Canyon Sand, and the Brushy Canyon Sands. The Williamson Sand, as is indicated on the type log, is a member of the Cherry Canyon Sand.

The depth of the Bell Canyon Sand is at 2595. Excuse me, 2905.

The depth of the Cherry Canyon is at 3824 and the depth of the Brushy Canyon is at 5452.

The structure map so indicates --

MR. STOGNER; Before we -- let's go back to that type log again. What's the red mark there?

A The red mark is the base of the Williamson Sand.

MR. STOGNER: Okay, so -- and that runs from -- could you give me the correlation of those two marks, the green and the red, as far as footage on this log?

A Okay. The top of that is at 4923 and the base of that would be 97 feet below that, which would be 5020, 5020.

MR. STOGNER: 5020, okay. Sorry to interrupt you there.

Q Mr. Rojas, if we look at all of these

different portions of the Delaware, identify at this time the primary producing interval in the Delaware, please.

A The primary, or the main producing interval of the Delaware section or the Delaware Group, is the Williamson Sand interval.

Q And that is the interval into which you are proposing to inject water, is that correct?

A This is correct.

Q All right, now let's go back to the structure map and I'd ask you first to identify the location of the subject well.

A Okay. The subject well is indicated by arrows, the directional distance from the lease lines. The Mobil 22 Federal lease is indicated with a yellow outline, that being the major portion of Section 22, which is outlined in yellow.

The proposed well is the No. 5.

Q And there are some additional tracts outlined in yellow. What are those?

A Those are additional Sun acreage tracts.

Q Are the offsetting operators indicated on this exhibit?

A Yes, they are.

Q Could you point out the location of the J. C. Williamson lease?

A The nearest J. C. Williamson lease is located in the north half of Section 26 to the southeast. The nearest well in the Williamson lease is the No. 4, Holly A Federal No. 4.

Q Now the wells that are spotted on this exhibit, are those all the wells in the area?

A No, these wells are those wells which penetrated the Williamson Sand interval.

Q Is one well -- has one well been omitted in drafting?

A Yes, there is a well which only penetrated the Bell Canyon formation and went to a total depth of approximately 3800 feet.

Q And whereabouts would that well be located?

A That well is located near the No. 6 Mobil 22 Federal Well, which is the north offset to the No. 5.

Q This also indicates the New Mexico/Texas state line, does it not?

A Yes, it does.

Q Is there an oil/water contact in the formation?

A The oil/water contact has been estimated to be at a -22 feet subsea.

Q 2200 feet?

A 2200 feet.

Q Now are there any dry holes indicated on this exhibit?

A Yes, there is one dry hole which is located in the southeast -- excuse me, the southwest quarter of Section 23. It is the No. 2, Booth Federal No. 2 --

Q Okay.

A -- which had a -- it was an early completion which did not completely attempt a completion in the Williamson Sand.

Q Are there any plugged and abandoned wells within a half mile radius of the proposed injection well?

A No, there are not.

Q At this time would you generally describe the geologic nature of this reservoir, and I'm talking about the Williamson Sand interval in the Cherry Canyon?

A The Williamson Sand, as is indicated by the structure map, is -- we've got a monoclinal dip to the northeast. The sand itself is a white to tan, very fine grained sand, with well rounded grains.

Q Is this a blanket type deposit?

A This is a blanket type deposit.

Q What is the gross thickness of the Williamson Sand?

A The gross thickness ranges from 70 feet to 105 feet in thickness.

Q What is the average porosity in the area?

A The average porosity is 17-1/2 percent.

Q And the average water saturation?

A Is 52 percent.

Q What would be the average permeability range in the area?

A The average permeability ranges from 35 to 40 millidarcies.

Q And what is the approximate depth of the top of the Williamson Sand?

A Approximately, using an average throughout over the Mobil 22 Federal lease, would about 5000 feet.

Q Now if we talk about the Williamson Sand, that's what you've been discussing, is that correct?

A That is correct.

Q How does that compare with other intervals in the Delaware, the Bell Canyon and the Brushy Canyon?

A The entire Delaware section was deposited in the same environment of deposition; therefore all of the sands are quite similar.

Q Is there any evidence of natural fracturing in this formation?

A No, there are not.

Q All right, would you now go to what has been marked Sun Exhibit Number Two and identify this, please.

A This is a gross sand isopach of the Williamson Sand interval. This helps to identify the broad deposit.

Q Okay, and what does this show you?

A Okay. This shows a -- the thickness of the Williamson Sand as being very continuous throughout the field ranging from the 70 feet to 105 feet, as I earlier testified.

Q And you have a cross section that basically depicts this in a later exhibit, is that correct?

A Yes, I do.

Q Let's go on to Exhibit Number Three and identify this exhibit.

A Exhibit Number Three is an isopach, net pay isopach, of the Williamson Sand, using a porosity cutoff of 14 percent.

Q And what does this show you?

A This shows a northeast/southwest trending development of porosity.

Q Okay, would you go and focus particularly on Section 22 and explain and show what you mean by this trending porosity?

A Okay. Within Section 22 we can see a development and enhancement of porosity going from northeast to southwest, which proceeds across from the northeast corner of that section towards the southwest corner of the section through the Worth Federal No. 2 Well, the Mobil 22 Federal No. 6, and into the Mobil 22 Federal No. 10 Well.

Q And so what you have here is a thickening of the porosity or thick that runs from the northeast corner running to the southwest?

A Yes.

Q And then on either side of that how does the formation change?

A We have a thinning of porosity development on either side of that thick as we do again have the thinning occurring on either side of the thick which proceeds from the northeast to the southwest through the Worth Federal No. 1 Well, the Mobil 22 Federal No. 4 Well, and through the No. 5 Mobil 22 Federal Well.

Q And so if I understand you, what you have is you have variations in the porosity that seem to trend northeast/southwest. You've got a thick kind of running through the center of it and thinning sections on either side.

A Yes.

Q How does the characteristic of the actual pay section vary as you go from the thick to the thins?

A The cause for the thickening of the pay interval is due to the coarsening of the sand due to the depositional environment. We have an enhancement of lithology character.

Q And what significance do you attach to this reservoir characteristic?

A This should enhance the orientation of production as far as the flow of hydrocarbons, flow of formation fluids.

Q And what do you mean by that? Are you talking about a radial drainage pattern or a directional pattern of some kind?

A Probably we'd have a radial pattern but it would be influenced by these northeast/southwest trending enhanced development of porosity.

Q All right, would you now go to Exhibit Number Five, which -- Number Four, which is the cross section and I'd like to direct your attention first to the index map and then ask you to go through the cross section as a whole and review that for the examiner.

A Okay. This map is a -- this structure map that we saw in Exhibit Number One, which is on top of the Williamson Sand. It does indicate those wells which are contained on the cross section which proceeds from east to west running from the Williamson No. 4 Holly A Federal Well through the Mobil 22 Federal Wells No. 1 and 3 and 5, and into the Mallon lease with the No. 7 and No. 11 Amoco Federal Wells.

This is a stratigraphic cross section on the base of the Williamson Sand.

Q Now, you've included on the cross section a portion of the log from each of these wells. As to the log on the Mobil 22 No. 5 Well, has that entire log previously been filed with the Oil Conservation Division?

A Yes.

Q All right, would you now go to the cross section itself and review the information contained on this exhibit?

A Okay. This is a stratigraphic cross section on the base of the Williamson Sand and what it indicates is the perforated interval of the Williamson Sand. You can see a very good continuous development of the porosity from well to well.

Q Would you go to the log on the Mobil 22 No. 5 and just point out and identify the injection zone, please?

A Okay, the injection zone would consist of that interval from 49 -- excuse me -- 4923 to 5020.

Q What conclusions can you draw about the reservoir from this cross section and the other exhibits?

A The exhibits that I've shown and this cross section help to show that we have a very continuous porosity development within the Williamson Sand which is a broad deposit, the continuity very, very well expressed.

Q Are the perforated intervals in each of these wells indicated on the cross section?

A Yes, they are.

Q Does the perforated interval in the closest Williamson well, which is the well on the righthand side of the cross section, does that interval correlate with the injection interval in the Mobil 22 No. 5?

A Yes, it does.

Q And between that are two other wells. Are the perforated intervals in those wells also in correlation with -- with both the Williamson Well and the injection well?

A Yes, they are.

Q In your opinion could injection of

fluids into the Mobil 22 No. 5 adversely affect Mr. Williamson's well from a geologic point of view?

A From a geologic point of view, prior to any effect on the Williamson well, an effect would be seen in both the Sun's Mobil 22 Federal No. 3 and the Mobil 22 Federal No. 1.

Q Do you know if water production is reported monthly on any of these wells?

A Yes, they all are.

Q And it would be reported if there was an increase in water on the two wells between the injection well and Mr. Williamson's property?

A Yes.

Q And based on your study, do you have any other general conclusions that you can (inaudible) in the proposed injection well cause waste and impair correlative rights of any other interest owner in the area?

A No.

Q Were Exhibits One through Four prepared by you or compiled under your direction?

A Yes, they were.

MR. CARR: At this time, Mr. Stogner, I would move the admission of Sun Exhibits One through Four.

MR. STOGNER: Are there any

objections?

MR. DICKERSON: None.

MR. STOGNER: Exhibits One through Four will be admitted into evidence at this time.

MR. CARR: That concludes my direct examination of this witness.

MR. STOGNER: Thank you, Mr. Carr.

Mr. Dickerson, your witness.

MR. DICKERSON: May I ask, Mr. Carr, is your next witness an engineer?

MR. CARR: Yes, he is.

MR. DICKERSON: Okay.

CROSS EXAMINATION

BY MR. DICKERSON:

Q Mr. Rojas, you testified, I believe, that you have picked an oil/water contact at -2200 feet --

A Yes.

Q -- subsea? Can you convert that to sub-surface for me?

A That would be dependent upon the well at which you picked the -2200 subsea. That has been defined by the lack of production beyond that point, beyond that subsea depth.

Q Well, at the proposed injection well, can you --

A Oh.

Q -- tell us where the gas/water contact or oil/water contact you picked is in that well subsurface?

A There would be no oil/water contact in the proposed injection well. We are above the subsea depth at the base of the Williamson Sand.

Q So the, as I understand it, the subsurface, your gas/water contact that you've picked is substantially below the proposed injection interval.

A Correct.

Q Would that be true as to all the wells that we're concerned with in this general area that penetrated this zone?

A That the -- I'm sorry, could you rephrase the question?

Q I'm just trying to establish that -- it appears that you're telling us that the gas/water contact that you have picked, or oil/water contact that you have picked, is in all cases as to the pertinent wells shown on your various maps, substantially below the proposed injection interval.

A Yes.

Q Okay. Do you know, Mr. Rojas, how the

Federal No. 5 Well was chosen for your proposed pilot waterflood?

A I believe it was chosen on a -- by the reservoir engineering group. Geologically all of the wells have got a very similar development of the Williamson Sand.

Q And is that correlation that you showed us on your cross section of the wells through which that cross section goes, is that all the wells basically that we're looking at on your various maps would correlate if we showed all of them on the cross section, would they not, as to that they're all productive from that Williamson Sand, as you've defined it.

A Yes, sir.

Q Okay. What can you tell us as a geologist, Mr. Rojas, concerning the -- any oil reserves under the spacing unit of your No. 5 Well, being the southeast quarter of the southwest quarter of Section 22?

A That they -- the -- we would be able to enhance the development of those reserves based on a waterflood project.

Q What is that well currently -- what's the status of that well?

A It is currently a producing well.

Q And do you know the current rate of production?

A Yes, I do, one moment. Currently that well is making an average of 8 barrels of oil a day, 41 barrels of water, and 20 MCF.

Q If -- if the job had fallen to you to pick an injection well for this pilot project, Mr. Rojas, would your recommendation have centered on any other well for geological reasons?

A Not for any geological reason would I pick any other well.

Q What about -- is there not a goal to get it centered or centered -- more closely centered in Sun's acreage?

A I believe that the location for the No. 5 Well, being the injection well, was chosen with the long term effects being considered as to what the pattern that could be developed, how it would be.

Q The engineering staff did that and not yourself?

A Yes. Yes, sir.

MR. DICKERSON: I have nothing further.

CROSS EXAMINATION

BY MR. STOGNER:

Q Mr. Rojas, so that I'm clear on the

lease, the Mobil 22 Federal lease, is it outlined by the yellow on these exhibits?

A Yes, it is.

Q Is that the only portion of the lease or is that the only -- there's no other portions not connected that is in this lease, is there?

A No, sir. The yellow, which is outlined in the northeast quarter of Section 22 is a conditional Sun lease. It is not the Mobil 22 lease.

Q Does Exxon operate the west half of the northwest quarter of Section 22 or --

A No.

Q Who has that?

A I believe that has reverted to Mobil.

Q Okay. So that would be the extension of your project for this lease, is that correct?

A Would be in the Mobil 23 Federal lease, correct.

Q Okay. Mr. Rojas, when we talk about the Williamson Sand, now, is that a known geological term or is it a terminology which is used locally in this area --

A It is --

Q -- or does this have another name?

A It is a local terminology which is used in many fields that produce from this interval, the Cherry

Canyon in this area.

Q Is it known by anything else?

A Not to my knowledge, other than a portion of the Cherry Canyon Sand.

Q What is the parameters of the Williamson Sand? I mean what are we finding right above the Williamson Sand and below it? Is that a sand interval or do we have a shale or what do we have bordering this?

A On either side of the Williamson Sand there is a high gamma ray reading which would indicate a more argillaceous or a shale interval, which would bound both the upper and lower limits of the Williamson Sand.

MR. STOGNER: Okay, I have no further questions of this witness at this time, Mr. Carr. You may continue.

MR. CARR: All right, at this time, if the witness at least is temporarily excused --

MR. STOGNER: Temporarily.

MR. CARR: -- I would call Richard Dillon.

RICHARD G. DILLON,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. CARR:

Q Would you state your full name for the record, please?

A My name is Richard G. Dillon.

Q Mr. Dillon, where do you reside?

A Midland, Texas.

Q By whom are you employed and in what capacity?

A Employed by Sun Exploration and Production Company as a reservoir engineer.

Q Have you previously testified before this Commission and had your credentials accepted and made a matter of record?

A Yes.

Q And you were qualified as a reservoir engineer at that time, is that correct?

A Correct.

Q Are you familiar with the application filed in this case on behalf of Sun?

A Yes.

Q Are you familiar with the general area and have you made a study of the Delaware formation in this area, particularly surrounding the proposed injection well?

A Yes, I have.

MR. CARR: Are the witness' qualifications acceptable?

MR. STOGNER: Are there any objections?

MR. DICKERSON: No.

MR. STOGNER: Mr. Dillon is so qualified.

Q Mr. Dillon, when did Sun originally file an application with the Division seeking authority to inject water in this well?

A The original application was completed in our office on January 23rd and the cover letter was written the first part of February and mailed to the Commission.

Q And --

A Of this year.

Q -- was this application filed on a Commission Form C-108?

A That's correct, it was.

Q And was a copy of this application at the time it was filed with the Division forwarded to Mr. J. C. Williamson as an offsetting leasehold operator?

A Yes.

Q And what happened at that time?

A At that time we were asking for administrative approval of our waterflood pilot. Due to the objection of Williamson, we were requested -- we were forced to come to a hearing in order to (unclear).

Q What is the current status of the Mobil 22 No. 5 Well?

A The status of that well is production, oil. As Mr. Rojas said, it's making about 8 barrels of oil a day.

Q All right. Is there attached to the C-108 that was filed in this matter a tabulation of data on all wells within one-half mile of the proposed injection well?

A Yes.

Q And did that include all the data that is required on From C-108?

A Yes, sir, it did.

Q Could you summarize for the Examiner exactly how Sun proposes to recomplete the subject well and convert it to water injection?

A The subject well is currently completed as a pumping oil well. The rods, pump, tubing would be pulled. New cement lined tubing would be run in the well. A Otis LocSet packer would be run in and set above the existing perforations. Some time during this process additional perforations would be added over the present interval in the density of one shot per foot, to give us a total of 89 holes over the perforated interval.

Q And what is that interval?

A The interval is 4938 to 5010.

Q Will the annular space be filled with fluid?

A Yes, it will.

Q And will Sun place a gauge on the well so that the -- to pressure test the fluid in the annular space as required by the Federal Underground Injection Control Program?

A Yes.

Q What is the source of the water that you propose to inject in this well?

A The source of the water injected into this well will be produced water from the Williamson Sand in surrounding wells.

Q Is this water from the same lease?

A Correct, from the same lease.

Q Is it limited to just the four offsetting wells or is it from the lease as a whole?

A It would be from the lease as a whole.

Q What is Sun presently doing with this water?

A Sun is presently in agreement with Mr.

Williamson to dispose of this water and for a fee we turn that water over to him to be disposed of.

Q And so you're paying Mr. Williamson to dispose of the water for you. What do you pay him, do you know?

A 35 cents per barrel.

Q Now, in your application, would you just review what volumes you propose to inject in this well?

A As we've asked for in the application, we would expect for purposes of this pilot to inject a maximum of 400 barrels of water per day with an average on the order of 300 barrels per day.

Q What is the ultimate volume you estimate would be injected?

A An estimated volume would be somewhere in the order of 1-million barrels.

Q How do these injection rates compare with the current withdrawals from the subject well and the four closest offsets to it?

A The 400 barrel a day injection rate would approximately offset the withdrawal production rate from the four offsetting wells.

Q And when you say would roughly offset that, are you talking about offsetting the water production or the total fluid withdrawals from those wells?

A It would offset the -- slightly offset the water production and compensate for some of the oil (unclear).

Q Would it be less than the total fluid withdrawal from those wells?

A Yes, it would to a certain extent.

Q Would this injection system be an open or closed system?

A It would be closed.

Q And does Sun propose to inject by gravity or under pressure?

A It would be under pressure.

Q What pressure do you propose to use?

A The application, we've asked for the maximum of 2000 pounds. The pressure we propose to use would be -- could be somewhat -- would likely be somewhat less than that. It would be what we decide would be required in order to effectively displace the oil in order to replace the voidage and essentially cause the waterflood to perform as we would expect it to.

Q Is it possible that a pressure limitation of .2 pound per foot of depth to the top of the injection interval could be satisfactory for your purpose?

A Yes.

Q Is it possible that you might need to go slightly above that?

A That's possible.

Q And how would you propose that that be handled?

A If there is any excess pressure that we would find that we would need, we would petition the Commission to perform step rate tests which would tell us where our parting pressure would be and avoiding any possible (unclear) injection.

Q And if it's possible, would you request that this order authorize those step rate tests witnessed by the Division to determine that you're not going to damage the confining strata?

A Yes.

Q Was a water analysis of injection fluid attached to the original C-108 in this case?

A No, it wasn't.

Q Would you refer to what has been marked as Sun Exhibit Number Five and identify that, please?

A Sun Exhibit Number Five is a laboratory water analysis of the water that's produced from the Williamson Sand. In particular it's from the No. 1 Mobil 22 Federal Well.

Q And what you're doing here is reinjecting into the Williamson Sand water from the Williamson

Sand, --

A That's correct.

Q is that correct? Are there fresh water zones in the area?

A Yes, there are.

Q And where are they located generally?

A They are located somewhat within and above the Rustler Formation.

Q And what is the approximate depth of the Rustler in this area?

A I believe the approximate depth of that is around 300 feet.

Q Is there any aquifer below the top of the Rustler that could be considered as a possible source of drinking water?

A I don't believe there's any possible drinking water sources below -- I believe there are intervals within the Rustler that are possible, but there's nothing below that interval.

Q Are there fresh water wells in the area?

A Yes, there is.

Q There is? How many?

A On the -- on our lease, to my knowledge, there is one.

Q And whereabouts is that well?

A That well is located slightly north of our No. 6, Mobil 22 Federal.

Q Was a water analysis of the water from this well attached to the C-108 that was filed with the Division?

A Yes, it was.

Q Mr. Dillon, have you examined the available geologic and engineering data on this area?

A Yes.

Q And as a result of that examination have you found any evidence of faults or other hydrologic connections between the injection well and zone and any underground source of drinking water?

A No.

Q Would you refer to what has been marked for identification as Sun Exhibit Number Six, first identify what this is and then if you will go through it, it's a multi-page exhibit, and review the information on each of those pages?

A Okay. Sun Exhibit Six is a set of production curves for the subject No. 5 Well on the Mobil 22 Federal lease, along with the offsetting four wells, which includes the No. 3, the No. 6, the No. 9 and the Amoco Federal No. 7, which is operated by Mallon.

Q Okay, let's go to the first page and

this in on the injection well?

A That is correct. This is the No. --

Q All right.

A -- 5, which is the proposed injection well.

Q Would you explain what each of those lines indicates and then what the exhibit as a whole shows?

A Okay. In particular on this exhibit we have a standard production plot. We have time along the X axis along the bottom. Oil production is shown by the solid line. The left axis shows the scale of the oil production, also the GOR and water production. That scale goes -- is logarithmic. It goes from 1 to 10,000. Again the oil production shown by the solid line, the GOR is shown by a solid line with intermittent dashes and dashed line depicts the water production from the well.

The -- in addition to the lines which include data which the public records obtained from Dwight's, which ends in November of '88, I have predicted a decline rate for the well, which is shown by a dashed line with single dots in between the dashes, and have annotated that with my interpretation of what the decline rate of that well would be out to its economic limit.

For the No. 5 Well that would be a 64 percent decline.

The economic limit used here is 3 barrels a day, which is a somewhat arbitrary number. Of course the economic limit would depend on the current oil price and operating expenses and other factors. The 3 was taken to be a conservative number that would represent under most cases an ultimate recovery from this well.

Q All right, let's go to the next page. This is the Mobil 22 Federal No. 3. This is the east offset to the proposed injection well, is it not?

A That's correct.

Q All right, let's just review this exhibit as to what it is designed to show.

A Again we have the same three curves plotted on this and again a prediction of the oil rate from the end of 1988 on. This well historically has shown a 41 percent decline. Due to well work and other circumstances there was an increase in the well in about the middle of 1988; some work that Sun performed on the well. Again that trend is somewhat established on that higher rate and that decline was used to predict into the future.

Q All right, let's go to the Mobil 22 Federal No. 6, the north offset.

A Again the same curves. Again a historical decline rate of around 41 percent. Again we've taken the last known rate and extrapolated from that point.

Q All right, and finally -- well, next to the last, the Mobil 22 No. 9, the west offset?

A The No. 9 again was off production for a period of time due to some operating problems; was brought back on, and that rate that we brought it back on was used as the starting point for the decline.

Q And the final one, the south offset, the Amoco Federal No. 7?

A Again the same set of curves, again an established decline rate approximately of around 40 percent. This one in particular is 39 percent, and again a forecast of what we would expect that well to produce on the (unclear) decline.

Q In looking at these decline rates, in your opinion is appropriate at this time to start evaluating the possibility of a secondary recovery project in this area?

A Yes, it is.

Q Would you refer to what has been marked as Exhibit Number Seven, identify that, and review the figures on this exhibit?

A Exhibit Number Seven is a summary of the analysis of the anticipated future production from the five wells that we are looking at. Included in that is the cumulative oil production to date, which is shown in the far left column there next to the well identification. It's shown that from these 5 wells we've produced 180,000 barrels of oil, which represents an average of 39 -- 35.9-thousand barrels per well.

The next column over we show the cumulative gas production from each of the wells. We made on the order of 300-million cubic feet from these wells.

Next is shown a decline rate that was previously annotated on each of the curves. It shows a trend in the area of around 40 percent with the exception of the No. 5 Well that we propose to convert.

The remaining oil reserves based on the decline rate and economic limit I previously mentioned, is shown in the next column. It shows that on the average we have a total of 43,000 barrels remaining to be produced from these wells under primary recovery for an average of 868,000 per well.

And in the last column we show the ultimate recovery under primary conditions, which is simply the summation of the first column with the next to the last column. It shows an average of 44.6-thousand barrels per well.

Q Now this exhibit shows what would happen if waterflood is not -- waterflooding or some other secondary recovery method is not introduced into the reservoir.

A That is correct.

Q Could you advise the examiner what percent of the original oil in place is being recovered through primary production?

A Primary production will result on the average, depending on the well and differences in operating conditions, et cetera, but the average would be on the order of 8 to 9 percent optimum from the original oil in place.

Q Would you now refer to Sun Exhibit Number Eight, which is again a multi-page exhibit and identify, first of all, what this exhibit is?

A Exhibit Number Eight is a set of three production curves. In this case we have the same axes as we had before; however, these three pages represent three analogy waterfloods that have been performed in Delaware sands in the general area that we're talking about here.

Q Now this are not Williamson Sand, is that correct?

A That is correct.

Q And from what interval are they producing?

A These units are producing from the Bell Canyon, which is a unit that is above the Cherry Canyon in the Delaware.

Q Would you expect these wells, or these units, when waterflooded, to perform in a similar fashion to what you'd expect with the Cherry Canyon and the Williamson Sand?

A Yes, we would expect the performance of these wells to give us an indication of what kind of results we could expect in a general (unclear).

Q All right, would you first go to the first page of this exhibit, the Ford Geraldine Unit and review that for Mr. Stogner?

A The first page, which is the, again, the Ford Geraldine Unit, which is in Reeves County, Texas, operated by Conoco, shows the initial production from the unit in the late sixties. The wells produced an approximate -- the unit was producing in primary conditions for, you can see, up until about 1972, in that order. The unit was converted to a waterflood project. Again the solid line shown on the graph shows the oil production. You can see the corresponding increase in oil production peaking about a year and a half later. A subsequent decline from that and as we can see in about 1982, we were reaching a fairly low value in the oil production. At that point a CO_2 tertiary recovery project was initiated in this -- this field and hence it's -- any more analogies with what we're looking at are not appropriate. However, looking at what we predict would happen had we continued primary production, as you can see there's a dashed line, dashed and dotted line, starting slightly to the right of the start of injection annotation that again is about 1973. It shows what we would anticipate that project to produce under continued primary conditions going out to the economic limit which would have been reached in about 1986.

Q All right, the dashed line which says 12 percent decline on it --

A That's correct.

Q -- that's production's decline under primary conditions.

A That's correct.

Q And then the dark line that goes about in 1972 or 3 that goes up above that line shows the oil response to waterflooding, is that correct?

A That is correct.

Q And it's the difference between those lines that reflects the kind of response you would hope to achieve in the Williamson Sand in a similar effort.

A That's right.

Q All right, let's go to the next page. That's the El Mar Delaware Unit and I'd ask you to review the information on that unit.

A This unit is in Loving County, Texas.

Again it was a Bell Canyon Delaware Unit. It's operated by Texaco. Again we have the same annotations. This unit was converted in about 1976 to water injection. We see again about a 12 percent decline would be expected if primary operations had been continued; however we see an initial dip due to conversion of wells and then an increase in oil production, again peaking about two years later at about 1000 barrels per day. That subsequently declines and goes on an established rate of about 20 percent decline. Again both of these were extrapolated out to an economic limit.

Q And let's go now to the Agnes Beckham Unit.

A This unit, which is in Reeves County, Texas, is operated by ARCO. Again the same annotation as before. We have an established 8 percent decline from the primary. In 1979 injection was started, as you can see again, the small dip in production due to conversion of producing wells and subsequent increase in oil rate, again in this case peaking around 190 barrels per day, that being sustained for a number of years and then going on a -- based on the last year's data that was obtained, 40 percent decline. Again both of those were extrapolated to the economic limit.

Q What does this exhibit tell you about the potential for waterflooding of the Delaware formation?

A It shows that in each of these cases a substantial amount of additional recovery was attained by waterflooding and that that recovery was attained in a fairly accelerated manner and that all the flood responded well to the injection of water.

Q Will you now go to Exhibit Number Nine and review that, please?

A Exhibit Nine is a summary of the three previous pages that we were just looking at. Shown across the top are the various units, each of the properties, the Ford Geraldine, the El Mar, and the Agnes Beckham. The operator and county are shown.

The next line down shows the cumulative production at the start of the waterflood; that is the primary production as it's been obtained from each of the units at the time that the flood were initiated.

For example, for the Ford Geraldine, about 1.9-million barrels had been produced. The next line down shows the estimated remaining recovery based on the projection that was shown on the previous graph. It shows that we would expect another 3.4-million barrels be produced from that unit. Estimated the ultimate primary recoveries, but the sum of those numbers show we would expect about 5.3-million barrels under primary recovery. The next line down shows the estimated total recovery after the start of the waterflood. This number would be compared t the second line, which is the estimated remaining primary recovery. Here we show about 5.8-million barrels as compared to the 3.4-million barrels we'd expect under primary. The bottom line is the difference between these two numbers. It shows the incremental secondary reserves, in this case about 2.3-million barrels of additional recover was obtained because of the waterflood.

That carries across the El Mar Unit, which we expected to have about 5.4-million barrels of primary recovery. That was increased by 1.4- million barrels because of the initiation of the waterflood.

Agnes Beckham, the same analogy, again additional recovery of 186,000 barrels from that property.

Q Now, Mr. Dillon, you've been talking about what you have characterized as analogous fields. I'd like you now to go to the particular injection well that is the subject of this hearing. Have you modeled this area?

A Yes, I have.

Q Would you refer to what is marked as Exhibit Number Ten and explain what this is and what it shows?

A Exhibit Ten is a plat with the wells of this area, the Brushy Draw Field. Shown in green upon the old 22 Federal lease outlined in green and hachured, is what is depicted as the area that will be affected by this waterflood pilot. This area was modeled using reservoir simulation techniques in order to predict what this particular flood would do in terms of additional recovery. The model that was created was designed to be a process model to give us an indication of -- of the -- whether or not if we would achieve any additional recovery and how much that additional recovery would be. It's basically a decision tool in order to proceed with our plans to convert this well.

Q And the model area was bounded by the four immediate offsetting wells that produce from this Williamson Sand.

A That's correct.

Q All right, let's go to Exhibit Number Eleven and I'd ask you to explain what this -- what this shows.

A Exhibit Eleven shows what we've used in the way of software in order to model this particular pilot. This is simply to document the software that was used to satisfy any questions in terms of validating this. The specific program is known as VIP. It'd developed by J. S. Nolen and Associates from Houston, Texas.

In particular in importance is the fact it's a three dimensional model that handles three phases of oil, water and gas. It uses black oil PVT properties, formation volume factor, viscosity, solution gas/oil ratio.

It accounts for gravity forces, viscous forces within the fluids, capillary forces within the pores of the model reservoir. Uses mathematical equations for fluid flow common to all modern simulators.

It is -- has been compared against other models against industry standards. It's been delegated by other companies, Conoco, Phillips, Standard Oil, Unocal, and many others have used this for results. It's used extensively for Prudhoe Bay, North Slope type of projects.

Q Has Sun relied on this model in the past? A Yes, we have. We've used it essentially exclusively since 1983 for simulation work in terms of black oil models. We benchmarked against other companies, against hand calculated analogies and there's no doubt as to its validity.

Q And this is an approach that your company commonly uses in determining whether or not a waterflood project should be implemented in a field.

A That's correct.

Q All right, let's go to Exhibit Number Twelve. This sets out basic assumptions that were utilized in the model and I think it would be helpful for you, Mr. Dillon, to go through this item by item and state what these assumptions are and if you can, you might notice which -- identify which of these assumptions are specific to this reservoir and which assumptions are general numbers utilized in those.

A Okay. The parameters that were used in the -- again on the model, are contained here in general.

The initial pressure, which corresponds to the initial pressure in the field, was 1800 pounds absolute.

The initial saturation pressure was also -- that was used was also 1800 pounds.

There is no PVT data that we have obtained within our lease that gives us 100 percent certainty that that's what the flow point was. This is a conservative number that's taken from correlation and the PVT data we're using here is from industry standard corrlations. If anything, we believe the (not clearly understood) probably somewhat higher but in order to not be over-optimistic to, you know, inaccurately predict what might happen, the conservative number of 1800 pounds was also used, thus there was no initial gas cap in the area. The oil was under-saturated but when the first barrel of oil was produced there was a molecules of gas began coming out of the solution.

The reservoir temperature is 105 degrees

Fahrenheit. That's been measured by logs.

The porosity on the average in this area is 17-1/2 percent. Again that's log measurement specific to this area.

Net pay, 48 feet. Again that's taken from log calculations.

The irreducible water saturation that was used in the model was 17 percent. This, along with the residual oil saturation and other rock properties, to a certain extent was taken from extensive core analysis that we've done in similar Cherry Canyon sands from a field that we operate in Loving County.

Q Have there been any logs in this particular area of the Williamson Sand?

A Have there been any cores in this particular area?

Q I'm sorry, yes.

A No, there have not been any cores in this particular area.

Q All right. Those numbers were used based on our knowledge of performance of the two fields. The wheat (sic) field is a somewhat poorer sand, thus the results that we'd expect would be somewhat pessimistic. By using these input parameters we felt that our standards would be met by the results of this model, then we have a fair confidence level, but what we'd actually see from the Brushy Draw Field would -- would exceed this.

The original oil in place that was calculated under a 40-acre tract by the model was 746,000 barrels.

The rock compressibility we used was 10 x 10^{-6} inverse psi.

The permeability that was used again was taken from core data from a -- was taken from core data from wells in the Cherry Canyon in Loving County, from the Wheat (sic) Field. This has been validated by numerous build-up tests that shows that we have an average of 5 millidarcies in that area.

Log derived permeabilities from the Brushy Draw Field show that we are more on the order of probably 35 to 40 millidarcies, thus we have higher permeability in this area, thus we would expect a quicker and hopefully somewhat more efficient response to the flood.

So again we've got a pessimistic number that we've input to the model. Again, knowing that if the results are satisfactory, that this would again give us a go ahead decision on our project.

Again the fluid properties initial pressure again was 1800 pounds with the (unclear) point.

Initial formation volume factor, 1.3

reservoir barrels per stock tank barrel. Solution gas/oil ratio of 800 cubic feet per barrel. That is also taken from production to a certain extent. The initial established GOR seems to be on the order of about 800 standard cubic feet, so that validates that number (unclear) in the Morrow.

And the water that was used was -- the properties were taken from correlations used industry-wide based on the knowledge of the water sample that we have of produced water from this formation.

Q Now using these assumptions, how accurate would you expect the modeling results to be?

A Using these formations it makes this model very specific to this area and to the, obviously, to the Wiliamson Sand in particular. It would give us, this amount of (unclear) gives a great deal of confidence in the numbers that we predicted from the model. Again, if anything, we would be looking for somewhat pessimistic results.

Q Now let's go to Exhibit Number Thirteen, again a multi-page exhibit. First, identify what these graphs are designed to show and then if you would go through them, please.

A Okay. The next set of graphs are simply the actual input data that was used in the modeling for --

on a graphical depiction so that you can see what actually went into the calculations that were made.

Again the oil PVT properties were taken by correlation. First we have the oil viscosity. We show that as we would expect decreasing as we go to a higher pressure. We've got pressure plotted along the bottom to the high of 1800 pounds. Oil viscosity went from zero to 2 centipoise on the lefthand scale.

Second, we have the oil formation volume factor again rising with increased pressure. Again we have the scale from zero to 1800 pounds on the bottom and the formation volume factor going from 1 to 1.4 on the left-hand side.

The next curve shows a solution GOR going from, well, essentially zero at atmospheric pressure up to a high, in this case, of about 530 pounds at 1800 pounds, or excuse me, 530 feet per barrel at 1800 pounds.

This is the differential liberation GOR that's used in the model. The slashed GOR, which I mentioned earlier, was 800-to-1, is shown by production. We have roughly paralleled this trend (unclear) not shown on this graph. This is what we think we'd expect in the reservoir itself.

Lastly we have a gas deviation factor, again starting with 1 at atmospheric pressure and decreasing.

These last two graphs show the relative permeability that was used in the model. First we have the oil/water -- excuse me, the oil/gas relative permeability. This was taken from the core data from the Cherry Canyon. The lefthand scale is the relative permeability to each of the phases going from zero to one. The bottom axis shows the gas saturation again going from zero to one. You can see the corresponding as we would expect dropping oil relative permeability as we increase gas saturation. corresponding increase in gas relative permeability.

Again this was directly from core data.

The next graph shows the oil/water relative permeability; same scale as before, zero to one on both axes, bottom this time being water saturation. This data is -- was initially taken from correlations for relative permeability for a sand with the properties that we have based on the fact that all the core data, or all the core tests that we've tried to perform on Cherry Canyon sand shows that such a uniform distribution in the core size and the grain size, that you get a piston-like displacement when you try to perform the laboratory test and that once you get water breakthrough you go immediately to 100 percent water saturation when you perform this test on a small, 1-inch diameter plug, which essentially shows you have piston-like displacement. You have essentially 100 percent sweep of the oil by the water, thus you have a very, very, very efficient process. That, we know, does not happen, you know, in the reservoir. We'd like that to happen but unfortunately it doesn't. We have some heterogeneity in the reservoir. In this case it's fortunate that we do not. These numbers were obtained, that we see on this graph, were obtained by the process of history matching or fine tuning the model such that it performed in an analogous manner to known production in terms of the water cuts and the oil rates that we see from the wells. Thus this curve in particular is unique to this area, to this model, and will help us in our prediction of what a waterflood pilot would be in terms of additional recovery.

Q Now, these graphs indicate how efficient waterflooding would be in the area, is that correct?

A That's correct. That would be --

Q And the last graph is the one that you have history matched to this particular reservoir that probably best shows that.

A That's correct.

Q And how would you characterize the efficiency of waterflooding in this area based on this exhibit?

A Base on these exhibits we would expect waterflooding to be a very efficient process here, a good tool to obtain additional recovery.

Q Now, let's go to Sun's Exhibit Number Fourteen. Would you identify this, please?

A Exhibit Fourteen, which consists of two pages, is a plot, graphical description of what the actual reservoir model looks like. The model consists of grid cells, each of which has a -- within the model period has a distinct water saturation, oil saturation, gas saturation, pressure, GOR within each of the cells. It's essentially a very, very rigorous calculation of the fluid flow through the reservoir.

The first graph shows an aerial view of the model. What we have done is selected a symmetry element of a 5-spot, which is essentially what we have with conversion of the No. 5 Well. We have reduced the well, excuse me, the model to two wells and in the forecast mode for secondary we have a producer, which in this case is depicted in the upper lefthand corner, being that corner cell. We have an injector in the opposite corner cell. In order to obtain a full pattern you take the mirror image of this grid, lay it over to the right and again take a mirror image of those two graphs, put them down, and you have your 5-spot element.

For modeling purposes it's common to use the smallest element possible in order to save computer time, to simplify the problem as much as possible. You obtain the exact same results that you would have with a larger model; however, it's scaled down, facilitates running, saves computer expense. It's an industry-wide practice for simulation work.

Q All right, Mr. Dillon, if you'd now go to the second page of Exhibit Number Fourteen and identify that.

A The second page is a cross section of the model grid that is if you're looking from the side. Five layers were used in the model. Each of these layers were assigned different permeability and porosity values based on the known log calculations. The averages of those, as we stated before, was 17-1/2 percent porosity; 5.1 millidarcies permeability. Those were distributed across for each of the layers as they're shown actually in the reservoir.

This layering gives us a more realistic prediction from the model in terms of what a flood would do in this reservoir.

Q All right. Let's go to Exhibit Number Fifteen. This is a grid production forecast, and I'd like you to review what the lines on this exhibit, focusing first on page one, indicate and also what the arrow on the axis across the bottom indicates.

A Okay. Let's see, I'm going to refer to the page that is labeled production forecast, which may be the second page in the way that these were stapled together. That is a graphical depiction of the results from the output of the model. The axes along the bottom, we have time in days. Each of the hachured marks -- each of the hachures across the bottom are 4 years, 1460 days, being 4 years, gives us a time frame along the bottom.

Oil production is plotted against the lefthand scale, which is logarithmic, goes from 1 to 100. Gas production rate goes from 1 to 100 and is shown on the righthand scale. These are 1/4 scale rates as obtained directly from the model we showed it in order to obtain numbers that would be applicable for a full well; for a full 5-spot we've multiplied these numbers by 5; however, -- or 4, excuse me; however, they give us the relative magnitude of the results that we would expect and we can, just by looking at the trends that we see, you know, basically get the gist of the results of the study.

First of all, you might like to look at the oil production from the two cases that were -- were run in order to compare the primary versus the secondary.

The primary case was run, which charted initial production modeled, you know, on the order of starting in 1985 when the wells were completed. It was produced until a time which approximates the present time, which is shown by the arrow, a little over 3 years. They're pointing to the bottom scale.

At that point the primary oil, which you can see is shown by a dashed line, and is annotated there at the very end of the curve, continued on its decline that we'd seen previously. It seemed like a very severe decline; however, we have a very compressed time scale. The decline obtained from that is on the order of 30 to 40 percent that was, you know, like that shown by the previous production from actual history.

It shows that, obviously, with no other operations going on that we would expect the oil rate to continue to decline through time and that we might expect it, perhaps, three or four more years down the road that we would -- at best we would be shutting most of these wells in due to lack of energy to produce under primary.

The primary gas is shown by the -- also by a dashed line. It's a little harder to read. It essentially parallels to a certain extent the oil line and then it turns around in -- 19 -- well, in about the second year of the project, about 1/2 inch over, turned around and goes up as more and more solution gas comes out of -- gas comes out of solution from the oil; we have what is essentially a solution gas drive reservoir here, thus the GOR's go up, gas production goes up, however, this is essentially just a venting of the natural energy that's producing the oil from the reservoir and essentially is a waste to a certain extent.

In order to compare that with the secondary, what we'd expect the secondary waterflood reserves, at the point in time where the arrow is at that is in present time in the model, one of the wells again was converted to an injector; hence we have our 5-spot. You can see by the solid line which represents secondary oil, that at that point in time where the arrow is at, that we lose production due to the fact that we convert one of the wells to injection. That well immediately begins injecting water. We see a somewhat, for a period of time, somewhat the same decline from the existing well. Then within about a year we see a turning around of that decline in oil rate and within two years a steep increase in the amount of oil we'd expect on a per day basis, and as you can see by the secondary oil curve, which is solid, it would peak, according to the model, results about 4 to 5 years further out, and would continue for an extended period of time that we anticipate quite a bit of recovery based on the parameters that we have here. The secondary gas follows that and is of less importance than the oil.

Q All right. Now go to what I guess in your copy is the first page of this exhibit and review that.

A That's right, this is the cumulative production forecast, which again is scaled with time along the bottom and oil production in thousands of barrels along the lefthand axis, gas production on the right, and again if we just focus on the oil, you can see that the solid line which ends up at the upper righthand side, labeled secondary oil, shows that from the model we would expect somewhere in the order of 73,000 barrels scaled down, of course. Again we would multiply this by 4 to get a typical 5-spot would be attained.

If you look back down on the lower left-hand side, where the labeled primary oil was contained, you'll see that the dashed line ends just above the R there and that we get somewhere in the order of about 17,000 barrels, which you can see the difference that we'd expect under continued primary oil operating conditions, which is the secondary flooding conditions.

Q How much of an increase do you anticipate you could get by the institution of waterflooding?

A The model indicates that we could overall obtain perhaps as much as a two-to-threefold increase in oil production over primary.

Q All right. Let's go to Exhibit Number Sixteen. Would you review the figures on that exhibit, please?

A Okay. Figure Sixteen is a summary of the reservoir simulation results. It's given for both the quarter scale, that is the direct model result, and that would correspond to the numbers that we see on the previous two plots, and also to a full scale, that is numbers that we can more easily relate to actual field production figures.

I'll go ahead and go down through the full scale column. You'll see the first line it shows primary forecast case. We have at present day time in the model the remaining primary production along the order of 12.8-thousand barrels from the well that -- the wells that would be producing at that point.

That agrees, you know, generally to the 8-to-9000 barrels that we'd expect from the decline curve analysis that we showed on Exhibit Six, I believe it was.

Ultimate primary recovery would be on the order of about 72,000 barrels.

Then we drop down under numbers that we obtained from the secondary forecast. First of all, once the well that is -- represents the No. 5 in the pilot is converted, within the first year it injects on the order of an average of 191 barrels of water per day. The rate that was selected in the model was based on two things. One is shown in the next line. We have a maximum bottom hole injection pressure of 1900 pounds, which is only 100 pounds above what we think the original pressure was in the reservoir. This is well below what we'd expect any kind of parting pressure to be. Again it's a fairly conservative number that we, in order to not -- engineers being conservative people not wanting to overstate what we think might be obtained from this, we would expect, as we've applied for, that we might go on the order of perhaps 100 barrels more than that, see a maximum of perhaps 400 barrels of water going into one well per day.

If that were the case, we'd expect to see a much faster response, perhaps a more, you know, accelerated production from the reservoir. The model again, which is somewhat on the conservative side, shows even with this lower injection rate that we would see response within the satisfactory time, within one to two years, and that we would have a successful project.

The next line down under pressure is cumulative injection after 20 years, which shows that in this well after 20 years of injection, we would be -- have injected almost a million barrels of water.

Next down we show that the oil production for the full pattern after start of waterflood would be on the order of 233,000 barrels. That, added to the production that we've already had, shows that we would get ultimate recovery of 293,000 barrels; thus we get an additional 220,000 barrels according to the model results from a full scale 5-spot pilot.

Q What conclusions have you reached from your study of this reservoir?

A The conclusions I've reached are that we have constructed a valid process model that shows reservoir simulation calculations that a secondary process would be very advantageous in obtaining additional oil recovery from the reservoir and that that recovery would be over, way over and above any anticipated primary recovery that would be remaining. We would extend the life of the field. We would certainly enhance our economic position by doing this and that it would be in general a very efficient and very economic project.

Q Without some effective secondary recovery technique, this additional oil would not be recovered, is that correct?

A That's correct.

Q Is there an optimum time for starting a waterflooding in a reservoir?

A In Delaware sands it's been our conclusion that the results you see will be pressure dependent and that as early in the life of a reservoir as you can we need to start water injection; thus we need to do this just as quickly as we can.

Q Now, Mr. Dillon, this is just a pilot project, is that correct?

A That's correct.

Q And expansion of this project to other portions of the field would, of course, be dependent on the results you obtain, is that correct?

A That's correct.

Q In your opinion will granting this application and recovering this additional oil thereby prevent waste?

A Yes.

Q Will the granting of the application impair the correlative rights of any other interest in the owner -- any other interest owner in the area?

A No.

Q Would the other owners in this subject lease share in the benefits that are derived from the waterflooding?

A Yes, they would.

Q Why do you feel that correlative rights of offsetting owners would not be impaired by injecting water into this formation?

A First of all, any water that's injected into this pilot well in this formation would be essentially contained within the 5-spot pattern around it within the 4 surrounding wells.

Q And why is that?

A That is simply the nature of the fluid flow in the reservoir, if you inject at a certain point that water will flow out in an essentially radial pattern toward any lesser pressure difference in the reservoir; thus we're injecting pressure -- or injecting water to increase the pressure around the one well. It flows to the surrounding wells which have a lesser pressure. There's no reason for that water to go any farther than that in that the pressure would be increasing as we got past those wells, thus the -- any effects that we would expect would be contained again within this area.

Q In terms of the amount of water you're injecting, how does that relate to the reservoir voidage?

A The amount of water we expect to inject would roughly equal the reservoir voidage from the surrounding 4 wells.

Q In a reservoir of this nature would you expect any preferential direction for this water to take other than the basically radial pattern?

A There's nothing that would give us any indication that there would be any other strong orientation, no.

Q Injecting these volumes at this location would you expect any sort of water bank to develop that would move across the reservoir?

A An area of higher water saturation would be developed but again would be contained within the 5-spot area. We do not expect any reservoir-wide effects to be shown from injecting in this one well.

Q If in fact something happened and such a water bank did develop and started moving off toward Mr. Williamson's leases, do you think that it would pose any immediate harm to him?

A No, I do not.

Q Would you be able to monitor the effect of this and the existence of any sort of water bank in the two wells that are Sun operated that stand between Williamson and the injection well?

A Yes, we would.

Q How close to the proposed injection well is, in fact, Mr. Williamson's closest well?

A I believe his closest well is on the order of 4,100 feet away.

Q Now, how close is the Mallon operated

Amoco well south of the injection well, do you know?

A That well is 1320 feet away.

Q Would you identify what has been marked as Sun Exhibit Number Seventeen?

A Sun Exhibit Seventeen is a letter that we received from Mallon Oil Company, specifically from Joe Cox, who's the Manager of Production Engineering. This letter is in response to our application and we've discussed to a limited degree what we would anticipate as a result from this. Basically, in a nutshell, the letter summarizes their support for our position and their hopes that we will carry this out in order to enhance the reserves in this area.

Q Were Exhibits Five through Seventeen prepared by you or compiled under your direction and supervision?

A Yes.

Q Can you testify as to their accuracy?

A Yes.

MR. CARR: At this time we move the admission of Exhibits Five through Seventeen.

MR. STOGNER: Are there any objections?

MR. DICKERSON: No, sir.

MR. STOGNER: Exhibits Five

through Seventeen will be admitted into evidence at this time.

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

MR. STOGNER: Thank you, Mr. Carr. Mr. Dickerson, your witness.

MR. DICKERSON: Mr. Stogner, if you would allow us just a few minutes to discuss this --

MR. STOGNER: About five minutes?

MR. DICKERSON: -- we'll try to keep it short and limit our time as much as possible.

MR. STOGNER: Okay. Before we go on that little five minute recess, I just have one clarifying question.

CROSS EXAMINATION

BY MR. STOGNER:

Q On Exhibit Number Sixteen, Mr. Dillon, you put maximum -- maximum bottom hole injection pressure. Is that what you're proposing at this time, 1900 psi?

A No, that is simply what was used in the model. Until we actually have an opportunity to go out and inject in this particular well in this formation, we won't know what happens. This is a conservative number that was picked in order to essentially, you know, see what the results would be if this were the case. It's not, you know, we'd -- I cannot predict what that number is going to be.

Q Why do you call this number a conservative number?

A We would, in order to obtain maximum benefit, probably pump water at whatever, you know, maximum rate we could without causing, you know, any possible harm to the reservoir, which, initially that limit would be based on parting pressure of the formation. This number is well below that as we would expect it. You know, this would be a safe number to use; we might be on the order of perhaps 2000 and 500, 2500 pounds might be, perhaps, a maximum of what we might see. Again that's without having run step rates tests or actually injecting into a well, we can't predict that.

Q All right.

MR. STOGNER: Mr. Carr, the C-102 was made an exhibit at this time; however, it was --

MR. CARR: C-108?

MR. STOGNER: Yes, I'm sorry.

MR. CARR: If you'd like me to move that, since it was the application I assumed it was part of the record. If you'd like it to be moved as Exhibit

Eighteen, we'll do that right now, Mr. Stogner.

MR. STOGNER: I don't think that will be necessary but however, I will have some questions on it.

MR. CARR: That's fine.

MR. STOGNER: I assume that Mr. Dillon is the one to ask those questions of.

MR. CARR: I think so.

MR. STOGNER: Okay, at this time we'll take a five minute recess.

(Thereupon a recess was taken.)

MR. STOGNER: The hearing will come to order.

Mr. Dickerson, I believe he was your witness.

CROSS EXAMINATION

BY MR. DICKERSON:

Q Mr. Dillon, how long have you been involved in your study of this area for injection purposes?

A The study of this particular area in terms of injection I've looked at on and off in my duties for the last couple of months.

Q Basically from the time the application in this case was filed?

A Yes. Yes.

Q Was there someone other than yourself involved in the study related to this proposed waterflood prior to that time?

A There have been previous studies that have been initiated that -- well, other people have looked at it, in those kind of terms, to the point where we were ready to, you know, initiate the -- the application. In terms of putting together the study to make a go-ahead decision and to -- to get a further definition on what kind of recovery we could expect, was left up to me approximately about that point.

Q Sun, as I understand it, more or less recently acquired this --

A That's correct.

Q When, approximately, was that?

A We acquired it and again (not understood) I believe it was in June of last year.

Q In June of 1988.

A Correct.

Q At the time Sun acquired this property had any reserves calculations been made prior to its acquisition from the previous owner?

A Yes, I'm sure there were.

Q Were you involved in those calculations?

A No, I wasn't.

Q Are you aware of them?

A I'm sure there have been some that were made. No, I'm not aware of any. When I began looking at it, it was close to that point. It was assigned to me in -- around September of last year and, you know, what -- and acquisition studies had gone through in terms of obtaining a price, you know, wasn't relevant. I needed to (unclear) the tract and see what my impressions of that reservoir were.

Q But you did not even ascertain whether such a study exists and compare it to the figures that you have testified to today?

A No. I'm aware that one exists and I am aware of the magnitude of the numbers that, you know, were obtained from that study.

Q Are they within the magnitude of the numbers you've testified here today?

A In general, yes, they are.

Q Correct me if I'm wrong, are not all the wells on the Mobil 22 lease into a common tank battery?

A At this point in time, the common tank battery? I can't answer it, sir, going into a common tank battery, no. I don't know.

Q Well, I'm curious. I noticed on some of your exhibits that you calculated on a well by well basis and I'm inquiring as to the sources of data that you used to make those calculations.

A Are you talking about specific test equipment?

Since the time that we've acquired the lease, the wells have been tested on an individual basis. Prior to that time it is my knowledge, I'm not aware specifically of what went on, but my knowledge that there was a period during which there was a common test facility for all of the wells and there was an allocation procedure in order to obtain individual well production.

Again I'm not -- I'm really not familiar with what -- other than, you know, what we've done since the time we obtained it and I know that from that time we have individual well tests, which, looking at the plots and looking at the time that we obtained the -- the property, whatever had been done in the past was more or less -- seems to be in line with what we were showing for individual wells.

Q Were you involved in the process of selecting the No. 5 Well as the proposed injector?

A No, I was not specifically. That was done just prior to the time that I started my study. I'm aware of the reasoning behind it and would have no reason to have picked any well other than 5.

Q Do you know why it was picked?

A Several reasons. One, primarily the fact that, as we can see from the production plot, it is a -- one of the lower rate wells. At this point we'd not want to convert one of the better wells.

Looking at the pattern around it, and assuming that we eventually do go to a 5-spot, that would mean converting other wells that had better production. If we moved elsewhere on the lease, we'd be getting into a situation where we were not, perhaps, even backed up, you know, with production. We would like a well that was in the center of four producers. You know, we could be getting to some other lease lines. You know. there were some other things that went into it.

Basically it was overall consideration of what an ultimate 5-spot would look like over at least our portion of the reservoir, combined with the fact that the well was at a fairly low rate at this point.

Q What is this reservoir, the geographical boundaries, just roughly, from you viewpoint and based on the current knowledge? I suppose you're anticipating a more widespread waterflood project at some point in time if the pilot is successful?

A That's correct. If the pilot was successful we would ultimately hope to unitize with offset operators, at least, obviously, the leases that we have, obviously if we would show this was positive, we would hope to have everyone's support in -- in taking it to whatever extent the cooperation would allow.

At this point, you know, there are -- the bounds of the reservoir are not definite and have not been, you know, defined by drilling to date.

Q Let me get some time frames in mind. How long, under the pilot project as you've described it, do you anticipate it requiring before a response one way or another is first observed?

A The -- based on the data that we have, we would hope and perhaps even see responses as quick as six months to a year. We would expect at the very least to see something definite before two years had lapsed.

Q Are you aware of the total volume of fluids produced from the No. 5 Well as of now?

A Yes, I am. I don't know that I have that specifically written down in terms of -- I have oil and gas cumulative from that well, production.

Q Well, it is over 200,000 barrels, is it not, total?

A Total, counting water?

Q Correct.

A Right offhand I can't, you know, that would not be a -- any adequate figure. My recollection, I don't, off the top of my head know what the water is.

Q Let's assume it is. We'll have some figures later, but --

A Sure.

Q -- in excess of 200,000 barrels has already been removed from the reservoir in which the No. 5 Well is producing. Now as I understand your pilot, you propose to inject at approximately 200 barrels per day?

A According to the model it showed that we would receive response with 200 barrels a day. Again going back, what I said, we would plan to on an (unclear) project you would want to inject at the highest rate you could that would not harm the reservoir.

For an earlier, you know, the primary, the first estimate was that we might expect a maximum of 400 into this particular well.

Q If harm to the reservoir did occur, how would you as an engineer observe it?

A That would be something that we would have to document through -- we would know what pressure would be our maximum pressure to do the step rate test. We would monitor the well, you know, we would stay below what -- what we would expect to be the reservoir pressure that -- or injection pressure that would cause us to go out of zone or whatever.

Q Either vertically or through channeling --

A Correct.

Q -- within the injection interval.

A Yes.

Q At any rate, the volume of water injected is going to have to replace that fluid volume previously removed prior to any response taking place in the reservoir at all, isn't it?

A No, that's incorrect.

Q Describe that for me.

A If at any point we stop the arrest of the decline pressure in the reservoir we will obtain additional recovery. If we do nothing, the reservoir pressure will continue to go down. If at any point we start injecting it would be beneficial to raise the pressure back up on the reservoir, which will be accomplished by over-injection above the voidage from the surrounding wells, which would be accomplished with a 400 barrel a day rate; however, if we simply match that, we would obtain additional recovery in that we would have more energy going into the reservoir; if we had any amount of energy into the reservoir we should expect additional recovery from it.

Q The energy going into the reservoir being the water under pressure.

A Correct.

Q And replacing what energy having been removed?

A The energy that's going to be removed is going to be due to production of the oil itself, water from surrounding wells, as well as the gas that's produced.

Q Well, over what period of time do you anticipate the success or failure of the pilot project to take to ascertain?

A Again, as I answered before, we would hope to see, enthusiastic to see results within six months, but we would not be disappointed to see something that occurred, you know, within the time frame of perhaps two years.

Q And by "results" you're by implication talking about successful results, hopefully, reflecting in what, increased volume of oil production in the offsetting wells?

A That would be correct, yes.

Q And if it is unsuccessful how would it be reflected?

A An unsuccessful project would simply be shown by a lack of change in the production rate in the surrounding wells. They would continue on their present decline and we would see, you know, that there was no additional response. There would be no additional oil that would be, you know, measured from those wells, and that would constitute a failure of this project.

Q Maximum of how long?

A You know, I can't specifically say what my decision would be in terms of whether or not we'd get out to the end of two years and -- and, you know, the results would depend on one, whether or not we see results from the injection well, whether or not we'd think we're pressuring our reservoir back up, whether or not, you know, again we see a definite response from the offsetting wells, you know, that's a decision that we have to make concerning all the circumstances at that point.

My results indicate that we would expect something on the order of two years, but I cannot definitely say that Sun would abandon the project at the end of two years if we didn't see a response.

Q If after that period of time instead of increased oil production you saw no substantial increase in oil production but a substantial increase in water production from your other four wells, what conclusion would you draw from that? Or in any one of them?

A It would be -- the scenario you're de- picting would be that we would have change in the -- in the water cut. We'd be expecting the wells that would be going up, if that were to occur, and I don't think that would be the scenario but if it were to occur, that would indicate that we were sweeping the water through the reservoir without sweeping any additional oil, which would be against what our intuition would say, but that would indicate it to be a failure of the project.

Q In your experience, Mr. Dillon, have you engineered for waterflood purposes other projects of Sun or --

A Yes, I have.

Q Other Delaware Sand projects?

A This is my first Delaware Sand. Well, I take it back. We have the Loving County project, the Wheat (sic) Field, both of which are in Cherry Canyon, so, yes, that's my --

Q It's currently under waterflood?

A Yeah, we are presently at this point in the process of converting wells to a pilot project as we have here. We've got approval and we are doing it at this point.

Q You have made some estimates, calculations of future remaining recoverable reserves.

A Yes.

Q During what -- over what period of time are those primary reserves recoverable under your calculations?

A It appears from the decline rates that, you know, a well such as the No. 5, which is nearing its economic limit, will become marginal, maybe on the order of a few years, where we're forced to shut that well in.

Some of the other wells are better. We're talking about three or four years. The maximum case I would anticipate, you know, from this area, again we have some wells that are better than others, just glancing at the curves shows that, you know, we're -- we're looking at five years maximum, probably.

Q But -- and you're estimating 8 to 9 percent, as I recall, recovery by primary means of original oil in place.

A Correct.

Q Is that consistent with your knowledge of other Delaware reservoirs that you're familiar with?

A Yes, from what I've looked at, the -- due to the, you know, the nature of the deposition, at least the core sizes we have and the sorting of the sands, and the fact that they're in all cases I've looked at, have been solution gas drive, we get, you know, whether or not outstanding terms in terms of recovery performance, and that you will have good wells that will obtain 10 to 12 percent of estimated original oil in place that a typical well will often be somewhat less than that.

Q Mr. Dillon, you compared three other, I believe, Delaware Bell Canyon floods, I believe --

A Correct.

Q -- for certain purposes to this proposed flood. Were those instituted through a pilot project consisting of one well on the edge of a lease?

A I can't speak specifically as to how those floods were initiated, no.

Q You don't know whether they involved a pilot study of any nature or whether --

A No, I don't.

Q -- they didn't?

A No, I do not. Those were, you know, maintained by other operators and I, you know, have not had the opportunity to obtain that data, no.

Q As I understand your computer modeling which you have done, you predict success for a field-wide flood based on the information that you know about this field now, don't you?

A Yes. The model specifically addressed the area that we're looking at. There's no reason at this point, you know, that we would anticipate that we obtain a different result from, you know, the carrying of this analogy, you know, to a field-wide project, no.

Q Is it your opinion that each of these Delaware wells on 40-acre spacing adequately and efficiently recovers all the reserves in place that can be recovered by primary means in this area?

A I believe that -- yes, that in this case 40 acres is a -- in terms of primary production is a -- the appropriate spacing and that if you were to go to a denser spacing I don't believe you would have economic, additional economic reserves recovered, and you can't go to a larger spacing, I don't believe you'd have the recovery there.

I think you would see interference between the wells on 20 acres. That's not to say that you might not want at some point to perhaps in fill and flood, something like that, in terms of primary production. At this point and stage of depletion of the reservoir, it would not be economic.

Q In the testing that Sun has done of the individual wells on the Mobil 22 lease, have you been able to see any communication between any of the wells on that lease currently?

A My knowledge in terms of testing Sun has done, we have drilled the No. 10 Well since the time that we acquired the lease based on the initial pressure, and I do not have that data here and I can't tell you specifically what it is.

We saw a, you know, some amount of interpretive drainage, you know, loss of pressure in that well when it was drilled, thus we, you know, interpret that that would be interference from the surrounding wells. We have reports of drill stem tests and from other operators that shows that, yes, that, you know, there is some amount of interference between the wells on 40's.

Q Okay. Back to the time that these various things, we've got a pilot project that you propose to institute, while primary production is declining.

A Yes.

Q And I presume that Sun would allow that primary production to decline to close, at least, to the economic limit? Or would you?

A I'm not sure I understand what -- what your question is.

Q Would it -- would it be Sun's -- you -- you testified that there, as I understand it, conflicting interests and you want to institute a waterflood project as early in the life of the depleted field as possible.

A Correct.

Q To gain certain advantages and yet you also, or an operator also desires to obtain the great majority of that production that can be efficiently obtained by primary production prior to instituting a waterflood, correct?

A If I understand your question, yes, a waterflood would be initiated as quickly as possible and as far as primary, yes, we'll produce -- continue to produce the wells in the primary until we -- such time we make the decision to convert to secondary. Yes, we have no reason to do otherwise.

Q Yeah, that's all I'm asking --

A Okay.

Q -- you to compare is the time frame of your pilot project as compared to the time frame of depleting the primary reserves on Mobils' lease -- or on Sun's lease.

A I believe what I've stated is that we should see results in that, you know, and be satisfied with the project within, you know, the time frame of six months to two years, which again surrounding wells would still be on production, although granted, as you say, yes, we would be farther down the depletion curve.

We have several reasons for wanting to

initiate the pilot. Obviously, one is to obtain a success. Success could be defined by simply being able to inject the amount of volumes that we think it's going to take to obtain the flood based on the confidence we have in the model.

That's something that, you know, we've -- you know, is a management decision to a certain extent, as long as the reservoir engineers can satisfy them.

If we go in, I would anticipate that -- and obtain the injection rates that we expect to see, that we'd obtain satisfactory results, Sun may elect, we cannot rule out the fact that within six months we would initiate the process to expand this lease-wide. There's enough confidence, I believe, in the calculations that have been done to show that if we can get the water in the ground we can get the oil out of the offsetting wells. I guess I'm -- what I'm saying is a positive last result, you know, last chance, yes, if for some reason we decide to wait and see until we, you know, have doubled our oil rate from the producing wells, perhaps, yes, we'll -- we'll have missed an opportunity in order to attain additional reserves because of the decline rate that has gone on due to primary, but I guess I can't specifically say what Sun is going to do. I can say what my recommendation would be.

Q You said, I think, that among other

reasons you picked the No. -- or Sun picked the No. 5 Well as the proposed injector here, because it was one of the lesser quality wells in the reservoir on your lease?

A At this point in time it has one of the lowest oil rates, that's correct, yes.

Q As an engineer do you have any explanation for the wide variation in the figures that you've calculated on your Exhibit Number Seven for the various wells?

A That's -- that would be due to a couple of things. One is timing of when the wells were drilled due to the fact that we know that there is some kind of drainage from offsetting wells, so the later a well was drilled, probably the fewer reserves we expect from it. There is a heterogeneity in the reservoir in terms of net footage of pay and porosity to a certain extent, so not all the wells are going to behave exactly the same. You know, it's these type things that would cause that to happen.

Q Have you checked for any mechanical explanation for the variation among the wells?

A Mechanical, no, no, I have not. To my knowledge the impression that, you know, at least under Sun's supervision that the well's been operated, you know, in a prudent manner, that, you know, we have not done anything that would not be shown to be, you know, efficient in terms of our operations.

Q Now with the exception of that last well, the No. 10 Well, Sun did not -- Sun bought this acreage with the remaining wells already located on it.

A That's correct.

Q Do you have any knowledge on the No. 5 Well of any data available which would call into question whether or not the frac that was instituted on that well was confined to the injection interval, the perforated interval?

A It is my understanding that the interpretation of the -- there's a temperature log that was run on that well, showed that the fracture was contained within the matter of, I believe it was a maximum of 15 feet above the uppermost perforation and 30 feet below the bottom perforation, thus it was shown that it was contained totally within the formation.

Q Sun ran that temperature log?

A No, that was run after the frac. Thus it was run by --

Q A prior test.

A -- a prior test, correct.

Q You testified that you believe the water injected into you proposed injection well will progress away from the wellbore in a radial and uniform fashion.

A To the extent, again as we just mentioned, of not having a perfectly homogeneous reservoir, there will be some sort of bias in that, but essentially we would expect a -- essentially a radial pattern. Obviously the wells have been fraced. There's some orientation that might be caused due to the hydraulic fracturing. There's also geologic factors involved. It would be difficult to say where, if any, there would be any bias at this point. The assumption is that there -- it would be (not clearly understood.

Q As a general rule, you're talking about the offsetting wells that have been fraced, how far out from those wells radius do you consider that the fracturing would occur from the treatment that you've given these wells?

A I have not studied that and was not involved in the design of the fractures. It is my knowledge and understanding that frac lengths on the order of 400 feet or less were probably used in terms of design.

Knowing what experience I have with design lengths versus actual lengths, we're talking about lengths that are -- are, you know, at best 400 feet away from the well.

Q If the injection water does encounter fractures created by the completion of those wells, how would you as an engineer observe this (unclear)?

A That would be indicated by an increased response from wells that were aligned with any bias that might exist.

Q Do you know whether or not your less than 10 percent recovery factor of original oil in place is consistent with the experience of operators over a longer term of Delaware wells in this area?

A I have not compared calculations with other operators.

Q Now the projections you made, as I understood your exhibits dealing with your extrapolated future production, and it was not -- that extrapolation was not based on the separately estimated production from each of the wells, was it?

A Could you explain what you mean by separately estimated?

Q Well, let's look at your Exhibit Number Six by which you established your decline rate for the No. 5 Well, for instance, the first page of that exhibit, as I understood your testimony, the dashed dot line, bold, black line, which appears to have commenced late in 1988?

A Yes.

Q Is an extrapolation.

A Correct.

Q And the solid line, representing the oil production, is based on actual production for periods previous to that. Why is it that you did not use the figures for that actual production for those for that substantially longer period of time in making that extrapolation for the future decline rate?

A I'm not sure I understand. All the data that is shown on this graph was used for making this extrapolation.

Q Maybe I'm simply asking why does the extrapolation start in November or December of 1988?

A Because it's just that is an extrapolation. It's not a -- I chose this for just illustrative purposes, not to continue -- I could draw the line on up and compare it to the previous -- I perhaps think that's what you're asking for here, and you could take, you know, a straight edge and do that. What it shows is that, you know, the weighting, knowing that there was some question about some of the previous production data, shows that, you know, basically the trend essentially since the time that Sun took the well over in particular, has been on a 64 percent decline. We've got several months of data which shows very good trend. That aligns well with approximately the last year of data which we have, again having some question as to that.

If you were to take it back to the original IP which would be an indication of what the well would make, which is somewhat higher than the sustained rate that we saw, you would be -- you might be somewhat, you know, have a somewhat lesser decline, however, knowing that, you know, the reservoir performances we see today is more important in predicting the future than what we saw three years ago, the weighting is obviously on the latest data that we have.

Q You know, what I'm really getting at, is look at your Exhibit Number Seven, Mr. Dillon, and your Federal 22 No. Well or Federal No. 3 Well as shown on there, 41 percent decline rate.

A Yes.

Q It's the second well shown on your Exhibit Number Six and --

A That's correct.

Q -- I'm just looking from what I can see through the exhibit and that decline rate for the actual production on the No. 5 Well appears to me to be basically tracking the decline rate for the No. 3 Well for the periods of actual production that we see. If you correlate the lines there, they're almost right on each other.

A Yes, which leads us to believe that perhaps the data is not particularly accurate.

Q But yet you --

A I don't know that.

Q I mean are they not? Hold it to the light and the lines track each other almost perfect for No. 3 and the No. 4 and yet look at the difference on your decline rates between the No. 3 and the No. 5. The No. 5 is the only well shown of those you studied that has such a precipitous rate of decline.

A Yes, and which is further evidenced by the last six months of data, eight months data that we know is very valid data. If we'd ignore the rest of the previous data, which we have some question about, that would be the result that we'd --

Q But do you as an engineer have an explanation for the gross, steep, more steep decline rate that you've calculated for the No. 5 Well as compared to any of those other wells?

A I have an explanation of the well. It is in a portion of the reservoir such that the parameters, such that that is simply the way the well is going to perform as we've seen by known production data.

The fact that other wells in the area have produced similarly is shown by the fact that the Amoco Federal Well again shows a roughly, approximately 40 percent decline, which we've seen over a period of years, which we assume has been tested on an individual basis and is validated.

Q Now, let's, though, compare the Federal No. 5 Well with the Federal No. 6 Well immediately below in your Exhibit Number Seven. Those are the two wells closest in ultimate recovery as you have projected them.

A Correct.

Q And those wells were drilled very close to the same time, were they not?

A That's correct. I would anticipate, I don't know the exact dates but judging from the time when production started for those wells, it appears that they would be perhaps within six months of each other, yes.

Q And yet according to your calculations we have a five-fold variation between those two wells in the amount of recoverable oil left in place.

A That -- that's correct.

Q Why is that?

A Due to the performance of the reservoir.

Q Is it your opinion that this well -- the difference could conceivably be accounted for by reason of a mechanical problem with the cement job, or something of that nature, on the No. 5 Well?

A No, I don't believe so. The data that I have the most confidence in shows it to be on a steady decline. I know of nothing operationally that would cause me to have a different conclusion than that, no.

MR. DICKERSON: No further questions.

RECROSS EXAMINATION

BY MR. STOGNER:

Q Mr. Dillon, I want to refer to the C-108.

A Okay.

Q I want to look at the tabulation of the wells within a half mile radius of the Mobil Federal No. 5 Well, about the seventh page, where you show the amount of cement.

A Oh, okay. Yes.

Q Have the top of cements been calculated on -- utilizing these figures?

A What page -- I'm sorry, I'm not sure what --

Q C-108, page 7, tabulation of all the wells within the half mile radius.

A Oh.

MR. CARR: Attachment One as an exhibit, up in the upper right.

A Okay, yeah.

Q You have shown the amount of cement that was put in the production casing but have the top of cements been calculated on these?

A Let me first of all state that, you know, I was not the person that put this exhibit or this together.

Q Oh, I'm sorry. Well, Mr. Carr, who should I be addressing this question to?

A However, if there any questions, you know, I'd be the closest one to answer.

Q Oh, okay, then I'm asking you that.

A Now, okay, could you rephrase the question? You're talking about cement and you're talking about -- is that what you just said, cement?

Q Yeah, have the top of cements been calculated with these figures?

A With -- I'm not sure which figures you're talking about.

Q With these figures on the page. It's clear right here.

A I don't see figures on that page that would lead me to calculate top of cement for those wells.

Q Okay.

MR. STOGNER: Mr. Carr, I suggest you get those and evidently these sacks of cement shown on these is not prevalent in this particular piece of paper. If you will supply me that information showing the sacks of cement that was actually run and the tops of cement.

MR. CARR: Okay. We misunderstood your question. You thought there was a cement figure there. There isn't one and what you want is the sacks and the tops, right?

MR. STOGNER: Yeah.

MR. CARR: Okay.

MR. STOGNER: It's there, cemented with so many sacks of cement, it's clear right here.

MR. CARR: All right.

MR. DICKERSON; It's not on mine.

MR. CARR: You know, we have a different exhibit; that's the problem with the question.

MR. DICKERSON: It's different from mine, too.

A I was --

MR. STOGNER: I wonder what happened --

MR. CARR: Let me see what you have.

MR. STOGNER: I have the C-108 that we got with the application.

MR. CARR: And this is the one I took out of the file and it has that number on it and it has a different attachment. That's why I said attachment.

MR. STOGNER: I'm not talking about Attachment One.

MR. CARR: Okay, let's see what we're looking at.

MR. STOGNER: I'm talking about that page 7.

MR. CARR: Go back to page 7.

A Page 7.

MR. CARR: I'm sorry, we have the wrong page.

MR. STOGNER: All right.

A Is that it, is that what we're looking for?

MR. CARR: This is the page that Mike has. Do you now have that one?

A No.

MR. STOGNER: Anyway we're going to need a copy of the cement calculated out on that.

MR. CARR: All right.

A I see there only shows to be one plugged and abandoned well in the model radius, is that correct?

A Yes.

Q And which one is that one?

A That, I think we're on the same list here, that is the -- it looks to be the Graham Bennett No. 1 --

Q Yeah.

A -- the first on the list. It was a shallower well, TD at 3000 feet.

Q Where does that show up on the map?

A I'm not -- do we have an exhibit -- I'm not sure we have an exhibit that shows --

Q (Not clearly understood) you need one.

A I take that back. That is shown on the plat that's with the application.

Q Are you talking about the (unclear)?

A Yeah, it should be on that plat.

Q Okay.

MR. DICKERSON: This didn't penetrate the zone, Mr. Stogner.

MR. STOGNER: Okay, that's what I was leading up to.

A No. Again it's got a TD of 3,050 feet.

Q Okay. Well, when I refer to this map that was put out with the application, what is the lease boundary of this lease?

A The lease boundary of this lease has changed since that map was drawn.

Q Okay.

A It includes all of the section with the exception of the northwest -- northeast quarter, in general terms. and except for the west half of the northwest quarter, and the correct boundary is shown on the exhibits produced by Mr. Rojas.

Q Okay. And the perforations for your proposed injection well are shown here, 4938 to 40 -- I'm sorry, to 50 --

A 5010, correct.

Q Okay. Okay, who owns that little west half of the northwest quarter, I'm sorry, the west half of the northwest quarter?

A Mobil. You have the original lease. This was obtained, I believe, originally as a farmout and that acreage in that quarter has reverted back to Mobil.

Q Okay. I don't show that they were notified.

A At the time the application was made they were not the operator of that. I do not -- I cannot answer whether or not they've been subsequently notified.

MR. STOGNER: Mr. Carr, do you

know?

MR. CARR: I don't know, Mr. Stogner. I will confirm.

Q Also Chevron has an offset to the lease. Were they notified?

A I cannot answer that. I believe that they were outside the 1/2 mile radius but I cannot -- I cannot speak to --

Q Well, you're putting a waterflood together on this lease. Everybody offsetting the lease needs to be notified.

In that case Mr. Williamson didn't need to be notified since he's without -- since he's further than a half mile. Why would you neglect Chevron and -- and not Mr. Williamson? Or does Mr. Williamson own something that I don't see here?

A That apparently was done as a courtesy. According to the regulation I believe that the half mile radius on the application --

Q You were putting a lease waterflood together on a lease. This would be like putting a waterflood together on a unit. You need to notify all the offsets to the lease.

So Chevron was not notified nor Mobil wasn't either, is that correct? Okay.

What is the maximum injection pressure which you're proposing on this well?

A The maximum pressure that we're proposing would be the initially a number on the order of perhaps a .2 psi per foot gradient as -- as is commonly allowed. We would, you know, should that not be sufficient, we would make application for a witnessed step rate test so that we could determine exactly what that pressure would be.

MR. STOGNER: And these 108's are covered at the hearing by the -- by the applicant. I apologize because I had to go through it myself because you didn't, to see if I had any other questions on it, and I apologize that it took that much time.

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

Mr. Carr, do you?

MR. CARR: No, Mr. Stogner. We will provide you with a summary on the notification and also the cementing sacks that we used in the top of the cementing each of those wells and we'll have that to you within a week.

MR. STOGNER: Okay, and if he's going to calculate them out, --

MR. CARR: Yeah.

MR. STOGNER: -- show me the calculations and what fill factor you used.

MR. CARR: Okay.

MR. STOGNER: What fill factor does Sun usually use, Mr. Dillon?

A I cannot speak for that being a reservoir engineer, we don't make that calculation.

MR. CARR: But we'll provide you with that, including the fill factor on each of those wells.

MR. STOGNER: Who usually does that?

A That would normally be done, probably by a production engineer.

Q And which there is not one here today, is that correct?

MR. CARR: That's right. Mr. Stogner, I think in view of your questions about the C-108 I would like to -- to move its admission. I think it might be important to have it, you know, as part of the case as it is so that we can supplement it.

MR. STOGNER: It is a part of the record already.

MR. CARR: Okay, and if it's all right with you, I'll just move its admission as an

Exhibit, I think it's Eighteen.

MR. STOGNER: Do you (unclear) the exhibit, Mr. Dickerson?

MR. DICKERSON: Substantially, (unclear) enough to suit me, Mr. Examiner. I have no objection.

MR. CARR: I will send Mr. Dickerson, of course, everything that we will submit to you.

MR. STOGNER: Well, I -- according to what Mr. Dillon tells me, we can't accept it because he is production -- I mean he's a reservoir engineer and he did not prepare it nor is that under his --

MR. CARR: All right, well, we will just leave it as just part of the Commission record, then.

MR. STOGNER: It's part of the record.

MR. CARR: All right. It won't be marked as an exhibit. It is simply the application.

MR. STOGNER: Based on what Mr. Dillon has told me. Okay, Mr. Dickerson, I believe it's your turn now.

MR. DICKERSON: We'll call Mr. Ralph Williamson.

RALPH WILLIAMSON,

being called as witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. DICKERSON:

Q Mr. Williamson, will you state your name, your occupation?

A I'm Ralph Williamson. I'm a petroleum reservoir engineer by professional training and my job generally is the drilling and production but I have done quite a bit of reservoir analysis.

Q And in what capacity are you appearing here on behalf of J. C. Williamson?

A I'm appearing here as a partner in the Williamson leases and also representing my father, J. C. Williamson.

Q You have previously testified, have you not, Mr. Williamson --

A Yes, I have.

Q -- as a petroleum engineer and your credentials are a matter of record?

A Yes, that's correct.

MR. DICKERSON; We tender Mr. Williamson as an expert petroleum engineer.

MR. STOGNER: Are there any objections?

MR. CARR: No objection.

MR. STOGNER: Mr. Williamson is so qualified.

Q Mr. Williamson, in the interest of brevity, can you briefly summarize for us the nature of your objections on behalf of J. C. Williamson to the proposed application of Sun?

A Well, I would first like to say that I -- we are very interested in getting a bona fide waterflood initiated in this area. This field is an obvious candidate for a waterflood. It's a simple reservoir compared to a lot of reservoirs that have been successfully flooded, and we feel that, like Mr. -- as -- according to what Mr. Dillon said, that as soon in the life of the reservoir, that you can initiate a waterflood, the better off that you are.

My objection is the manner in which this pilot flood is proposed, we're going to be presenting evidence that we do not think the cement job is adequate in the well. I don't think that the putting 400 barrels a day in the well on the edge of a lease when there's 100 wells in the -- in the reservoir, is going to do anything but flush out some remaining primary reserves that could have been recovered. Although they're not our reserves I hate to see oil go to waste. The country needs the oil. But it's just that I have never seen a waterflood that the fluids that are injected were not injected in such a manner that the desired hydrocarbon fluids were not forced to the desired location. I think it's presumptuous that this water will be put in the ground and magically the oil is going to end up in the offset producing wells. I just don't think that's going to happen.

I calculated, my reservoir numbers were very similar to the ones that Sun presented. I think those are very reasonable reservoir numbers. They had a factor of a flushable reservoir volume of 59 percent; I thought -- think it's around 50. These are within the range of differences of engineering opinion.

They have done more computer modeling than I have and have, you know, access to superior resources as a major oil producer, but if you make a simple volumetric calculation reservoir volumes at 400 barrels a day, it would reach the -- not the other well but just the 40-acre boundary, you're talking about a million barrels of flushable volumetric pore space and at 400 barrels a day we've talking about eight years before any injected fluids get anywhere.

Q You're talking to the boundary of the spacing unit where the proposed injection well --

A And not even into the adjacent 40 acres that the proposed production wells, or the production wells to receive response.

Mr. Dillon stated that he thought that there was only three or four years of primary production left, and at 400 barrels a day, this, if he is correct, this field will be long dead and buried by the time they see a response on this injection.

Q Mr. Williamson, have you been, or J. C. Williamson either, been contacted in any way by Sun discussing what they're planning here?

A We were notified of the proposed pilot injection. We have not been contacted about starting an engineering committee to discuss how we want to waterflood this reservoir. We have not really had any contact with Sun as an offset operator. I'm down there in a position to observe their -- their manner of operations and I have no particular -- they have been a very -- very good about keeping their wells going and looks like that they're doing a fine job in the field. But this particular thing, I just -- I just think it's a complete waste of time to do a small thing like this. It will take too long, you won't see response, and I personally think, based on the nature of the reservoir, which I've studied very carefully on our wells, and the type of frac that was put on the offset wells, all this pilot is going to do is flood out part of the reservoir and as soon as they get in the proximity of these other wells, especially if they get into the -- contact the frac radius around the wells, that the water will channel into the production wells and all you will have done is bypassed a lot of oil that will never be recovered.

Q With what, an ultimate damage to the reservoir that could --

A Oh, I think so. If you're going to flood a field, you have to force the fluids to go where you want them to; they're not magically going to go; the pressure is going to take them where it's going to take them. That water and that oil and gas do not know that they're magically supposed to go to these production wells. They're going, the fluids are going to migrate towards the production -- the areas of low pressure and it will be areas where they've been drained out and in this type of well the area that has been drained out is around the wellbore and in the immediate proximity of the frac radius. The frac radius is drained first and then it rays out, it's more like a -- instead of a radial thing, it's more like a big sausage. This was been very well established in the computer modeling. You frac wells but this is how the drainage patterns area established and it's not a radial manner.

These wells needed to be fraced but to properly flush the fluids I feel, and I think that Sun will feel when they put a full blown waterflood together, that this field will need to be infilled on 20 acre spacing with the new wells functioning as injection wells. They may be fraced, they may be lightly fraced, and the old wells, including this Mobil Federal No. 5, will be one of the production wells that will receive any fluids coming by and they will have the opportunity when they drill the new wells to very carefully do their cement jobs and test them so that they will know that the formations are -- the formation fluids are in fact staying in the formation and that they're not migrating up and down the hole in some way in a manner that won't accomplish anything but make a mess.

Q So do I understand that part of your objections to be the lack of input allowed yourself and your father in -- in the study that Sun wants to undertake?

A No, they have a right to do anything they want to on their own property. But to me, if you have a reservoir like this and there is no -- the legal boundaries have nothing to do with the reservior boundaries, that they can do their studies, but if you're going to put together a waterflood, you need to get all of the people that own a part of the reservoir involved so that you don't have a mistake and think when Sun injects this water, if they got permission to do this, they would not see any response except with time increased water production in the offset wells, become discouraged, not pursue the waterflood initiative, and in the main, millions of barrels of oil could be left in the ground that could easily be produced by a coordinated effort of all the owners in the field.

Q Barrels not necessarily under your leases, under Sun's lease, conceivably.

A Well, the future of this field is a waterflood. I don't think there's any question about it, and it needs to be initiated as soon as possible, but a small pilot flood which will contact a small area, and we're going to be presenting testimony that we don't think that the water will stay in the Williamson Sand in the Mobil Federal No. 5, that this would just be a complete waste of time and that this is time we don't have -- have to waste.

Q Now I understand that in your review of Sun's cross section they submitted --

A Uh-huh.

Q -- it was substantially the same cross section as you had intended --

A Yes, --

Q -- to submit, Mr. Williamson.

A -- that's correct.

Q And you heard the Sun geologist and engineer testify as to the nature of the Williamson Sand reservoir and the wells in the area?

A Yes, I did.

Q And you had no --

A I had no objection to anything that the geologist -- any part of the geological presentation.

Q Let me ask you to refer, Mr. Williamson, to what we have marked as Exhibits Two and Three, and there will not be any Exhibit One since we abandoned the cross section.

First, look at Exhibit Number Two. Tell us what it is, how it was prepared, and what it shows.

A Well, Exhibit Two is a columnar tabulation of the reported production from the proposed injection well and it shows to me, we had a couple months last year, this was about the time a sale was made when no reports seemed to have been made or we don't know that, we may not have just found them, but it tells me that this is -- is not a particularly good well but it is certainly not a dead producer, it will continue to produce hydrocarbons in paying quantities and that if this is converted to injection all the remaining primary reserves that this well is capable of producing will be lost.

Q Let me ask you to compare -- first state the total cumulative production from your Exhibit Two for that No. 5 Well.

A Well, the tabulation, and it's approximately two months short, I don't think much oil was produced, or actually three months short in that period of time, but I show a cumulative oil production, based on what's reported, of 38,636 barrels.

Q As compared to what from Mr. Dillon's projection under his Exhibit Number Seven for total ultimate recovery from that well?

A Well, it shows and if you had the last month's and current month's production, it will -- it's shown that it's already produced more than he shows to be -- to have -- it's already produced more than what is shown to be the total cumulative ultimate recovery.

Q Then do you disagree with the opinion that he expressed and is shown in that Exhibit Number Seven, that that well is for all intents and purposes substantially depleted for primary production?

A This, the Delaware does not do that. The Delaware does not respond in the manner in which they drew the decline. The Delaware decline gets flatter and flatter with time until ultimately it will keep milking along at 6 or 7 or 8 barrels a day till your equipment wears out. I feel, and I did some rough calculations, that there is between 30 and 40,000 barrels of remaining primary reserves in this well, as much as has been produced already. We think there's a mechanical problem with the well but -- and that will certainly slow the rate of recovery, but the reserves are feeding into the wellbore and if you do a reservoir calculation based on the log and you put a 10 percent primary recovery factor, that gives the well just short of 85,000 barrels for a cumulative of ultimate primary recovery, and it's made 38, so that leaves 47,000 barrels that this well could produce in the future, admittedly at a low rate. I feel like if they fixed their cement problems that the water rate would go down and their oil rate could easily go up and they make it into a commercial well.

Q Is it your opinion that those additional reserves that you foresee as being in that spacing unit in the wellbore of that well will not be recovered if the proposed pilot --

A I have no confidence in the 400 barrels to be put in there at that rate over the time period that they propose to do it, and I believe that all remaining primary reserves will be lost and that it will damage the overall prospect of a waterflood for a field that's going to have a hundred wells now and be infilled probably with as many more, and the ultimate cost could be in the tens of millions of dollars of products lost and all of the things that come along with a project being cancelled.

Q Do you feel, Mr. Williamson, that at the present time with current production rates and the status of the existing wells in this fairly large reservoir, that the full fledged waterflood is appropriate for this time?

A I feel very, very confident that that needs to be done. From what I've seen of Sun they have a lot of good experienced people that could do -- I would like to see Sun do the waterflood. They already own a position in the field and my dealings with Sun have been very favorable and I feel like they'll do an excellent job once they get on the right track and propose a waterflood that will work, and, as I've said several times, I don't think what they're doing is going to do anything besides make a mess.

Q So it's the lack of a cohesive field-wide plan to recover this obtainable oil that gives you the principal problem?

A Yes, that's -- that's correct.

Q Identify Exhibit Number Three for us and briefly tell us what that document shows.

A Well, this is a document obtained with permission of one of the principals of Challenger Energy, Incorporated, which was the company which sold the property to Sun, and this is a reservoir study that was initiated in '85 early in the life of the field, but it -- it covered the first six wells that were drilled and included the No. 5, which is proposed to be changed to an injection well, and it shows on the average that these wells have -- had at that time six wells, close to 100,000 barrels each remaining primary reserves, and that contrary to what was reported, instead of having three or four or five more years of primary production, that the -- that the life goes at least to the year 2000 and that the way this is calculated some indefinite time beyond that, but 2000 is 11 years from now and it still had some life according to this study that was done by Williamson Petroleum Consultants in Midland, a very reputable --

Q Not related to you.

A Not related to me, no.

Q All right. Mr. Williamson, as I understand it, this reserves analysis covered the lease that we're talking about here, the 6 wells on the Federal 22 Lease --

A Yes.

Q -- that Sun now operates, and the projected total recovery primary production methods of oil from those wells under this analysis, at least, was 607 -- 671,845 barrels?

A Yes. Some of that has been produced now that the early years are gone, but that will show a remaining of like a half a million barrels or so, and if you look at the geology of these wells, there seems to be very little difference between the individual wells. They have performed differently but that -- things happen to wells and some wells do better than others, but from a geological point of view they ought to be like a litter of pups, they ought to be just alike.

Q As I understand it, the No. 5 Well was included in this analysis. It is merely not broken out separately as Mr. Dillon --

A Yes, that's correct.

Q -- calculated, and the difference between the projected total reserves to be recovered under primary means for these wells is substantially different under the two interpretations, isn't it?

A That's correct.

Q Which would lend credence to your opinion that there is additional primary oil to be recovered under that spacing unit?

A Yes, as I calculated, I felt like there was 47,000 barrels left primary recovery in the No. 5, albeit at small rates, but I just felt like that they could do a little work on the well and get that oil coming and get this back up in the range where -- they're making money now -- but get it up where they could make substantial sums by continuing to produce the well.

Q Mr. Williamson, is there anything further you'd like to add with respect to your position to this application?

A No, I cannot think of anything else.

MR. DICKERSON: Okay. Mr. Examiner, I move the admission of Applicant's Two and Three. There is no No. One.

MR. CARR: I'd like to ask a couple of questions on Three.

MR. STOGNER: Mr. Carr.

CROSS EXAMINATION

BY MR. CARR:

Q Mr. Williamson, the Williamson that prepared the report is not related to you.

A No.

Q Do you know who prepared this report?

A The actual engineer, it says Michael E.

Black, I do not know him.

Q Did -- was this prepared for you?

A No, this was prepared for Challenger Energy.

Q And do you know what methods were used to make these projections or estimate these volumes?

A Williamson Petroleum Consultants have their own very acceptable reservoir programs that they -- they have sold it to a lot of people. There would be not a question in my mind that this was competently done. These are one of the leading petroleum reservoir consultants in Midland.

Q Were you involved in the preparation of this in any way?

A Not at all.

Q And do you know what methods exactly were used by Mr. Black in preparing it?

A There -- there is really one method. You examine the available data and you get a data sheet and you put it into the computer program and out comes the --

Q Do you know how that computer program (unclear) was constructed?

A I have worked with the program on several occasions and have been satisfied with the results. They just -- you have a sheet and you analyze your decline curves and put the pricing and input data and you come out with a net present value. I say this program may vary slightly from other versions but they would depend, their manner of calculations (unclear) all comers, I feel sure.

Q You didn't prepare this, though.

A No.

Q And you didn't confer with Mr. Black?

A No.

Q And you don't know what variations they might have in their program as opposed --

A No.

Q -- to some other companies.

MR. CARR: I object to the admission of Exhibit Number Three inasmuch as it was not prepared by Mr. Williamson, by anyone for Mr. Williamson. He cannot confirm what variations might exist in it and he was not involved in any way in its preparation and I think it's not -- they've laid an improper foundation and it cannot be admitted.

We have no objection to the admission of Two.

MR. STOGNER: Mr. Dickerson?

MR. DICKERSON: We merely offer it for such a way as you deem it deserving and if you don't deem it deserving of any, trash it.

MR. STOGNER: We will accept Exhibit Number Two as evidence at this time.

Exhibit Number Three, based on Mr. Carr's objection, we will not allow this into evidence.

MR. DICKERSON: I have no further questions, Mr. Stogner.

MR. STOGNER: Okay. Do you have another witness, Mr. Dickerson?

MR. DICKERSON: Yes, sir, very brief.

MR. STOGNER: All right.

MR. CARR: I have a few questions.

MR. STOGNER: Oh, I'm sorry, go ahead. I thought you'd already done that.

MR. CARR: Maybe I did, even I don't know.

Q Mr. Williamson, we're here because of an objection that was filed to the application of Sun signed by J. C. Williamson. That's your father.

A Yes.

Q In that letter of opposition it's stated, "The proposed injection zones are actively producing in the immediate area and are considered to have major oil and gas reserves that would suffer irrevocable damage of water if water was injected in the manner proposed by Sun Exploration and Production Company." Okay, my question is this. Is the basis of your concern not that the wells on your lease, 400 -- 4,100 feet away --

A Uh-huh.

Q -- are in danger of immediate water damage from the injection?

A The immediate water damage from this injection well will be felt in the closer offset wells, I don't think there's any question of that.

Q Well, we understood that to be you were concerned about your lease and that was the focus of our case and I'm just trying to establish what you're not objecting to.

Would you agree with us that if there was a bank of water that moved through the reservoir that you would certainly see it in the wells between your lease --

A Oh, certainly.

Q -- and the injection well.

A Certainly.

Q All right. Now, you're not the operator of the lease on which this well is located, is that correct?

A Of which?

Q Of the proposed injection well, the Mobil 22 --

A No.

Q -- No. 5. Do you have any ownership interest in that lease at all?

A No.

Q And what you're, if I understand your objection, it is to the -- to Sun approaching this with a pilot waterflood project instead of coming forward with a field-wide program or plan to waterflood.

A That's correct.

Q And if such a plan was developed, I'm not asking you to commit yourself, but you would be interested in it and supportive of some effort to institute a secondary recovery.

A Oh, yes, very definitely.

Q Okay. In this regard to you agree that time is really of the essence and the sooner an effective secondary recovery effort was implemented, the better it would be?

A I would say the sooner a field-wide secondary recovery method could be implemented it would result in a lot of oil being produced that in all likelihood could be lost.

Q And again time is important in that regard. You're one of the major operators in the field, isn't that correct?

A Yes, I have an interest in all of my father's leases and in the southern part of the field I operate wells in my own name. My actual ownership position calculated out is actually greater than my father's in this, in this field.

Q Have either you or your father made any plans or undertaken any initiatives to institute a secondary recovery project in the area?

A We feel that our experience has been primarily in primary production. We would like to see an operator of greater experience than we are to head this program off -- up, and we would have no particular objection to Sun being that -- that party.

Q Are you aware that Sun has experience in waterflooding --

A Oh, certainly.

Q -- other reservoirs?

A Certainly.

Q Are you also aware that in their experience the way to go about this is to first institute a pilot project to confirm their --

A Well, I would -- I would -- I would -- I have not seen any place where that has been done.

Q Okay.

A Especially in the Delaware, and there are very few reservoirs in the Lower Delaware in that country. This is really virgin territory.

Q Uh-huh.

A There's probably not more than half a dozen certifiable Cherry Canyon Fields in Lea and Eddy County. Most of the fields are Upper Delaware Bell Canyon and the experience is much greater with that upper sand series but the upper sand series has substantially different characteristics, so --

Q You haven't undertaken any studies because the real focus of your effort is in developing the primary --

A Yes. Well, I have --

Q -- aspect of the reservoir?

A I have done a substantial amount of reservoir work in this particular reservoir, principally because of my ownership of the reservoir. I was glad to see these reservoir parameters being presented. They are very close to ones that I felt were very reasonable. Porosity was very close and many of the things that were presented I thought were very well done.

Q Okay. When you go about instituting a waterflood project, let's go back. Let's look at the Delaware wells and you talked about the decline rate in those wells not being as projected but actually flattening out and they sort of plug along for a long time.

A Yes, that's correct.

Q Okay. And you would expect that with the No. 5, even though now I think your own words was it wasn't a particularly good well, you would expect it to extend for some period of time.

A Yes. In my experience in the Delaware, especially in this field, wells just -- they'll milk along as long as the equipment holds up. If you have a major mechanical problem they may be prematurely plugged because a 5 or 6 barrel a day well, you can't afford to spend very much money fixing holes in the casing or anything of this nature.

Q When they plug along, they're still in the primary producing phase, isn't that right?

A Yes, that's correct.

Q So whenever a waterflood is instituted, there are going to be some wells that are still capable of primary production that are going to have to be converted to injection. Isn't that fair?

A No, that's not necessarily -- not right at all.

Q You could drill injection wells?

A That is the normal procedure is not to convert a producing well to an injector. The normal procedure is to drill new, carefully engineered wells as injectors, but your cores, the cores are analyzed, the cement is very carefully done, and it's just, I would say in my experience, extremely unusual that old wells are used for injectors; just -- it's just not -- it's just hardly ever done that I have been able to see. New wells are drilled to receive the water.

Q Even if the old wells are located where an injection well would be appropriate?

A If you have the decision made that the flood should be done on 40 acres, the 40-acre spacing is there, so you have to use the wells that are there.

A 40-acre pattern flood, a deal like this, I feel it should be a point where they drill all the infill wells, I think when you get to these small corners that haven't been drilled they will find almost primary pressures and for awhile they'll produce like the other wells aren't even there, but they will be able to use the advanced technology to use the core data and advance cementing techniques to make sure that the new wells will stay in zone better and they'll design a fracture treatment for water injection instead of primary production in the area. There's a difference there.

Q Are you suggesting that they produce the wells for a time first and then convert them to injection?

I just didn't understand what you said.

A Well, when you -- when you have a pattern waterflood, the wells don't magically get drilled at the same time. It takes time to do that and most people would like to get a little return on their investment while all this is going on. So it's very common, Shell does it in Denver City and ARCO does it in Denver City. Most of your floods, injection wells are produced for awhile if for no other reason just to see what, you know, what was in it. It's not a long term thing.

Q So what you are recommending is that instead of converting existing producing wells, that new wells be drilled for injection purposes, produced for a time and then at some time converted.

MR. CARR: I have no further questions.

CROSS EXAMINATION

BY MR. STOGNER:

Q Mr. Williamson, who was the Williamson Sand named after, either you or your dad, you or the Mr. Williamson here?

A I'm going to have to claim my dad on

that.

Q Oh, I was confused.

A He's the explorationist and he was the one that when that -- when that field was found there was no -- nothing out there. This has all been subsequent to that. He picked the sand out. Nobody knew what was there and we tried it and the initial well about blew us off the lease. So this initiated a play out there and fortunately it -- it spread out and became a nice reservoir that is probably in the 100, I don't know, 10-to-20-million barrel category..

Q Which is this lease -- here's the next question, then. Which -- which well is the discovery well for the Williamson Sand?

A You look on the lease and I believe in Section 25 there's a UCBH lease.

Q Yeah.

A It's the No. 1 Well there.

Q Okay. And is that still producing today?

A Yes, it is.

Q What's the rate out of it today?

A It's making about 25 barrels a day.

Q And when was it discovered?

A I'm thinking along in late '82, early

'83.

Q Okay. Have any of your leases, when I say your leases, the Williamson leases, have you had any infill projects or programs instituted on your leases?

A We would have done some of that and were thinking of it prior to '86 and I think everybody here knows what happened in '86 and '87 and '88 in the oil business and we were suddenly too poor to do anything besides just continue to produce the wells that we had.

Q Does this Delaware Sand extend down in Texas and is there any --

A Yes, it is, it does. Exxon and Texaco have several -- quite a few wells down in Texas.

Q Has the Williamson Sand pretty muchly been drilled so whenever I look at the batch of wells in the -- this area, that's in the Williamson Sand and that would outline the Williamson Pool, or a good portion?

A There are, you know, I have well files on almost every well in this field. We have been able to trade information with Texaco and Exxon and I can say that there -- we have reached the reservoir boundary to the south, to the east, and there's a -- there's a portion of the field that goes up to the north. Sun presented a very excellent map there; that 2200 foot contour is the -- you still get a little oil there but it's not commercial, mostly water, and to the south, in a portion of the -- on the west side but the west and north part of this field has not been firmly established. The wells tend to get a little weaker up that way but there could be an enclave to the northwest that has not been drilled.

Q Are the characteristics of this reservoir that you have seen in your wells pretty muchly homogeneous with the other wells to the south and to the north?

A Relatively speaking, as petroleum reservoirs go, this is a very homogeneous reservoir. If you took a core you would see a lot of zones or a few zones that would seem to carry from well-to-well in a fortunate manner, which would expedite a good response to a waterflood. The reservoir character gets poorer as you go to the northwest and we have a couple of wells that are in Texas that are either on the edge or beyond the edge of the field and they just -- you lose reservoir character. You lose porosity, but the zone does continue on up -- up dip for several miles. There just is no -- no trap there.

MR. STOGNER: I have no other questions of Mr. Williamson. He may be excused.

Mr. Dickerson?

MR. DICKERSON: Mr. Craig Huber.

JOHN CRAIG HUBER,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR DICKERSON:

Q Mr. Huber, will you state your name, your occupation and how you're employed?

A My name is John Craig Huber. I work for Buckeye, Incorporated, sales engineer in Midland, Texas.

Q Mr. Huber, will you briefly describe for us the nature of your experience with the proposed injection well which is the subject of this hearing and the other wells on the Federal 22 Lease that we've heard discussed?

A Well, at the time the well was drilled I was employed by Challenger Energy. We drilled it and I filled out the application to drill and the subsequent sundry notices that were filed and all records the OCD in Artesia --

Q Let me ask you, what was your connection with -- what was your job? What did you do as far as drilling and completing those wells?

A Well, I -- essentially I was in the pre-planning of the drilling and completion procedures and then also involved with the well site completion during the completion process. I was a partial owner in the well --

Q All right, and with regard to the proposed injection well, the No. 5 Well, were you in charge of drilling and completing that well?

A Yes, yes, I was.

Q And do you know of your own personal knowledge because you were there the manner in which that well was drilled and completed and put to production?

A Yes, I do.

Q Tell us when the well was spudded and analyze for us the drilling and completion process that that well underwent.

A Okay. I'll, like I say, I'll refer back to the sundry notices and it was spudded July 30th of 1985. The well was drilled to total depth; reached total depth August the 11th of '85 and ran 6175 foot of 5-1/2 casing; cemented 375 sacks of Halliburton Lite followed by 450 sacks of 50/50 PAZ C, 6 pounds of salt, and a quarter pound of FloSet.

Q Now a cement bond log was conducted on that well, was it not?

A Yes, it was, there was a cement bond log.

Q And it's on file with the Division.

A It should be; I feel that it was submitted.

Q What in connection with that cementing job that you conducted and witnessed on that well leads you to believe that there is any possibility of migration from the proposed injection interval to another zone in the formation?

A As I continue with the sundry notice, what we did is we ran pipe on the well and ran the cement bond log and went ahead and perforated and acidized with 2000 gallons of acid, I believe, and since we had had some problems on some prior -- prior wells in a different area, we elected to run a temperature survey and what's call a dummy frac ahead of the major frac job as re- commended by Halliburton, to determine that we were in fact in zone. We, like I say, we ran the base temperature log and we ran a 5000-gallon dummy frac on the well --

Q And you're talking about the perforated interval which is the --

A Right, the perforated interval.

Q -- subject of this hearing.

A Right.

Q All right.

A And so we ran the 5000 gallon dummy frac at 20 barrels a minute and this consisted of a 30 pound cross link gel that we would -- we would continue the final frac job with, except it was void of sand, you know, in order to, we were out of zone, in the hopes that we wouldn't prop it open much.

We ran the temperature survey following the dummy frac and as indicated the entire dummy frac went through the top perfs, I'm not sure, this says the top perfs and -- and communicated up to 5850 feet, I believe. I mean, I'm sorry, 4840 feet.

Let's see, yes, 4850, says, "Temperature survey indicated fluid going to top perfs and communicating to 4850 feet."

At that point we elected to go ahead with the frac job. At Halliburton's recommendation we dropped 450 pounds of blocking agent, which is a naphthalene, oil soluble agent, with 2000 gallons of KCL water and the pressure, when the blocking agent reached the perfs increased from 700 psi to 1700, so we felt that we had effectively blocked the area of communication, so we continued with the frac and completed the frac job.

Q 1700 being sufficient to frac that --

A Well, that's -- that's pretty evident. That was pretty indicative of what you'd start out with on a normal frac job in that area. You'll start out with 1700 pounds, increasing it at a rate of 40 barrels a minute and then drop back probably about 900 by the time you finish.

So we felt like that we treated primarily with the frac job the -- the Williamson pay zone.

Subsequently to that we, as we began producing the well, the naturalness, being an oil soluble blocking agent, obviously, began -- you could smell it as it -- as it was broke by oil and we felt like we saw a change in the oil cut with -- within a short period of time after putting it, putting the well on production. At that time it was on gas lift and so we had some pretty responsive -- well, it was easy to get good cuts to see where we were and what type water cut we had; whereas we started with like 50 percent, it dropped to about 20 percent and the production indicates that it probably produced about 20 percent oil cut.

Q Now you, as a principal in the previous owner Challenger, operated the well from the time of discovery until the sale to Sun at the end of 1988?

A Yes.

Q During that period of time did that well perform up to expectation as compared to other wells in the area?

A Well, from log interpretation I always felt like the well never performed as well as you would -- take a look at the log calculations, and I felt like it never did perform as well as it should have.

Q Did you have any reason to believe what had been the reason for that?

A Well, I've always -- I've felt that it's probably been influence from water production in that zone at 4850. It's a real high, it's a higher porosity zone and reading 2 ohms, I mean, you know, it's an obvious high water content zone, and I've always felt like we were producing both zones, and it was influenced by that up above.

Q And the forms you have summarized and looked at as you've testified are those forms on file with the Division, are they not?

A Yes, sir.

MR. DICKERSON: I have no further questions of Mr. Huber.

MR. STOGNER: Mr. Carr?

CROSS EXAMINATION

BY MR. CARR:

Q Mr. Huber, what is your background? Are you an engineer or --

A No, I'm not. I -- I am -- was formerly with Harvey E. Yates Company in Roswell, New Mexico, as a drilling and production field man. My educational background is -- is I have a BA in political science.

Q And you're what is known as a practical oil man.

A I'm known as a practical experience, I believe, is what -- what I'm referred to.

Q The final temperature survey on the well indicated the frac, did it not, from about 4926 to 5040?

A Right.

Q And is it your testimony that the fracture goes beyond that interval?

A No.

Q You were saying --

A The final frac, what I'm saying is the final frac job, I feel like went through the -- or is confined to what the -- what you indicated as probably the Williamson Sand boundaries. Prior to that, the temperature survey indicated we were communicated 100 feet (unclear).

Q But that was prior to this.

A Right.

Q And is it your opinion that disposal of the proposed volumes at this interval would not stay in the Williamson?

A I do not feel, especially when you get your pressure, you're going to put a lot of water in there, that the day you catch pressure, I feel like it's going to go to the zone of least resistance and that's going to be the higher porosity and water-bearing formations.

Q About what depth?

A At 4850.

Q 4850, are those --

A In that range, yeah.

Q Are those producing intervals?

A No.

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

MR. STOGNER: I have no questions of this witness. He may be excused.

Mr. Carr?

MR. CARR: Yes, sir.

MR. CARR: Is that a rule book you've got in that red book?

MR. CARR: Yes, sir, this red book is a rule book.

MR. STOGNER: May I borrow that for a second?

MR. DICKERSON: 701-F.

MR. STOGNER: Mr. Carr, I'd like to recall Mr. Dillon at this time.

RICHARD G. DILLON,

being recalled as a witness and remaining under oath, testified as follows, to-wit:

RECROSS EXAMINATION

BY MR. STOGNER:

Q Mr. Dillon, let's look at your Exhibit Number Six. Are any of these wells classified as stripper other than the No. 5 Well?

A I cannot answer it in terms of regulatory definition, or classification whether or not they're stripper.

The rates are such that, no, this is the lowest well. It's producing on the order of 8 barrels a day. The rest are in excess of 10 barrels a day, if that's what your question is.

Q How much above 10 barrels of oil per day are they producing?

A Various amounts. Again I'm referring, you know, to my plots. Let's see, they might have a date. The No. 6 specifically was making in November 12 barrels a day. The No. 9 was making 17. The No. 3 was making 31 barrels a day, and Mallon's well, the No. 7, Amoco Federal was making 14 barrels a day.

Q Now in looking at the decline curves on the Exhibit Number Six, it appears that with the decline of 41 percent which you show it won't become a stripper well until 1991 for the No. 3. Am I reading that right?

A That's correct.

Q And for the No. 6, it should become a stripper well either tomorrow or the next day.

And the No. 9, some time this summer.

A That's right.

Q And the No. 7 Amoco Federal sometime this summer before.

Have they reached an advanced state of depletion, in your -- in your opinion?

A Yes, in general they have.

Q Okay.

MR. STOGNER: Are there any other questions of Mr. Dillon?

He may be excused one more time.

Is there anything else, Mr. Dickerson, Mr. Carr?

MR. CARR: I have a closing statement.

MR. STOGNER: As far as witnesses, other than closing statements?

All right, we're ready for closing statements.

Mr. Dickerson, you may --

MR. DICKERSON: Mr. Examiner, I'll keep it very brief.

Rule 701-F, and we recognize that it has been the practice of the Division over the years in various and sundry cases to permit pilot water-flood projects, our objection, Mr. Examiner, is not to the permitting of any pilot waterflood project, it is to the permitting of this particular project under the facts that have been related here today.

Rule 701 provides very briefly that in addition to the, as you had foreseen, in addition to the requirement that the area in question proposed for waterflood be in an advanced state of depletion and sub-stantially all of the primary production have been depleted prior to the institution of a waterflood project, but in addition to that the rule goes on and defines the project area. It defines it as all spacing units operated by the owner of that proposed injection well, either ad-joining it or offsetting that injection well, which in Sun's case, based on the maps that it presented of its acreage position, would require all that acreage.

We're not arguing that a pilot project included in all that acreage be forced on Sun in lieu of the one that is proposed, Mr. Examiner, we're asking to have the reservoir viewed from a broader angle.

This is a well established, not totally established as to the -- all the boundaries of the reservoir at the present time, but it is from the testimony of all the witnesses fairly rapidly approaching that point.

The most efficient method of secondary recovery, and I think that all the rule does is require this engineer -- or recognize this engineering fact, requires that the successful operation and institution of a secondary recovery project for the benefit of all the various and sundry owners and operators of wells within the area of that proposed reservoir, be done on a carefully managed and scheduled basis.

Our objection to Sun's application here is not to the institution of a pilot project. It is to the institution of a pilot project consisting of one well on the -- 990 feet away from the southern boundary of Sun's acreage, not related in any way that we can see from the maps and evidence introduced here today, to the reservoir as a whole. It may be perfectly the correct engineering thing to do to institute a pilot project if that were the case but there's no evidence that the parachuting of a pilot project into an arbitrary space on the acreage owned by the applicant is the proper and most efficient way to institute a pilot waterflood project, let alone a field-wide reservoir-wide project for the benefit of all the parties.

We think the problem can be addressed by communication between the parties. Until we were presented with the evidence that Sun presented today we had no idea what the proposed project was. There has been a lack of communication between Sun and Mr. Williamson testified that Sun is a well qualified operator with experience in flooding zones; that he has no particular reason to object to, would simply like to be included in that and some discussion among the operators of large interest within this reservoir toward the end sought by all, that is the ultimate recovery of the maximum amount of oil possible by secondary and primary means from the entire reservoir, not simply from the 40-acre tract on which Sun's pilot injector well is to be located.

And our basis for objection to the application is on that. It's a practical application of engineering objection, not throwing in the face of Sun, just take your waterflood and leave. It's talk to the other operators of substantial interest in the area and come to a mutually satisfactory arrangement for recovering the maximum amount of oil.

MR. STOGNER: Thank you, Mr. Dickerson.

Mr. Carr?

MR. CARR: I hate to agree with Mr. Dickerson on anything, you feel like you're giving up your ground, but there has been a lack of communication here.

We came in here expecting the issue to be damage to Mr. Williamson's properties to the south and the east and that is not the concern.

He's concerned that something be done. The only person who's proposing to do anything, however, in the area is Sun. Williamson noted that he had no ownership in the Sun lease. He indicated that, you know, you could do anything with your property that you wanted but he wants to come in because he is concerned for the reservoir and tell us how we ought to institute or take the initial steps toward a waterflood project which we're all agreed, I think, is important for the reservoir and it's important that it be done quickly.

Everyone agrees that Sun is a competent operator to do it and yet the minute Sun takes the initiative they should and starts instituting a water-flood, pilot waterflood project, the objection is not that it's wrong, not that we shouldn't do -- come in with a waterflood, but we need to have a carefully -- one on a carefully managed and scheduled basis.

I submit to you that's exactly

what we've proposed. We've proposed taking a conservative approach, injecting relatively small volumes of water but water volumes which our experts have told you will within a, hopefully, six month period of time, but we believe within a 2-years period of time, to confirm our modeling, and when will then be the basis to expand a project and go out and do this with some information behind us, not just go out trying to tie up a large portion of the field and drill wells and produce them and say, yes, these are primary production, we're just waiting to convert them to injection.

I don't understand that. We stand before you as the only people doing anything with people screaming something must be done, but nobody's willing to let us go forward. They scream, this is just a random selection. Well, hell, it's only 900 -- heck, it's only 990 feet -- you told me about that and I -- 990 feet from the southern boundary of their lease. But I think you should note that Mr. Mallon, the owner of the property south of that, is supporting this. He's come in and stated it's about time somebody do something like this and he's supporting the effort.

We find ourselves in kind of the anomalous position, standing before you, the only people ready to do anything, and a room full of people screaming something must be done on a timely basis, that we're the ones who are qualified to do it and everybody else wants to call the shots.

Well, I think there are certain things that you don't have to decide.

You don't have to decide whether or not waterflood is in the best interest of conservation. It is.

You don't have to decide whether or not waterflooding is going to ultimately prevent waste, because it is. Everyone agrees on that.

And in this case the other question you have to decide is whether it's going to impair the correlative rights of anybody else, and the only people protesting are people who admit that they're concerned about damage to their wells.

We think that consistent with the rules and orders of the Division, consistent with your overall statutory directive to prevent waste and protect correlative rights, you must grant the application of Sun so we can forward with plans to develop this reservoir in a prudent and economical fashion.

Thank you.

MR. STOGNER: Thank you, Mr. Carr.

Is there anything further in this case?

Mr. Carr, I want to hold the record open on this case pending the information for the tops of cement. Also I was looking through the application and I did not see that Meridian was notified and --

MR. CARR: All right, we will take --

MR. STOGNER: -- so I'll either need proof of notification within the time limits or waivers of Mobil and Chevron or within the 21 days in which they have for a proper notification. Hopefully, you'll be able to get a waiver from Chevron and Mobil and Meridian.

MR. CARR: We will pursue that and stay in touch with you and copy everything for Mr. Dickerson.

MR. STOGNER: Thank you. Anything further?

The hearing adjourned.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C. S. R. DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9646, heard by me on 12 April 1989.

[signature], Examiner
Oil Conservation Division