NEW MEXICO OIL CONSERVATION DIVISION

STATE LAND OFFICE BUILDING

STATE OF NEW MEXICO

CASE NO. 10495

IN THE MATTER OF:

The Application of Beach Exploration, Inc., for amendment of Division Order No. R-9453 to increase the injection pressure limitation in its Red Lake Unit Penrose Waterflood Project, Eddy County, New Mexico.

BEFORE:

DAVID R. CATANACH

Hearing Examiner

State Land Office Building

June 25, 1992

REPORTED BY:

DEBBIE VESTAL
Certified Shorthand Reporter
for the State of New Mexico

ORIGINAL

A P P E A R A N C E S

FOR THE NEW MEXICO OIL CONSERVATION DIVISION:

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BY: **W. THOMAS KELLAHIN, ESQ.**

I N D E X

E X H I B I T S

EXAMINER CATANACH: At this time we'll call Case 10495.

MR. STOVALL: Application of Beach Exploration, Inc., for amendment of Division Order No. R-9453 to increase the injection pressure limitation in its Red Lake Unit Penrose Waterflood Project, Eddy County, New Mexico.

EXAMINER CATANACH: Are there appearances in this case?

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin, Kellahin & Aubrey, appearing on behalf of the applicant, and I have two witnesses.

EXAMINER CATANACH: Are there any other appearances? Mr. Carr?

MR. CARR: Do you need an attorney or a witness?

EXAMINER CATANACH: Will the witnesses, please, stand and be sworn in.

[The witnesses were duly sworn.]

MR. KELLAHIN: Mr. Examiner, I have two witnesses to present this morning. Mr. Hal Gill is a petroleum engineer and is the managing engineer for Beach for this particular waterflood project.

He's here to testify for you to explain the current status of the project. He was the engineering witness that presented the initial waterflood project to you at your hearing back in January. I've given you a copy of the current order for your information.

Mr. Gill will tell you that the current limitation for his project is 900 pounds. That's based upon recent step-rate tests. He is requesting that that surface pressure limitation be increased to 1500 pounds.

In addition, because of the issues concerning fracturing the Penrose Formation of the Queen Pool, Mr. Gill has hired a consulting engineering firm from College Station, Texas, S. A. Holditch & Associates. They are recognized experts in fractured reservoir information and studies.

And Mr. Bradley M. Robinson is our engineering witness. He has prepared an engineering study on this particular reservoir and on this waterflood project. It is his conclusion based upon that study that we may safely increase the surface pressure limitation up to the 1500 pounds and that will be his presentation.

At this point I'd like to call Mr. Hal Gill.

HAL GILL

Having been duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Hal Gill. I'm an engineer for Beach Exploration in Midland, Texas.

Q. Mr. Gill, on prior occasions have you testified as a petroleum engineer for the Division?

A. Yes, I have.

Q. Pursuant to your employment as an engineer, have you continued to study your company's Red Lake Waterflood Project in the Red Lake Queen Grayburg Pool in Eddy County, New Mexico?

A. Yes, sir.

Q. Is that a project that you manage for your company?

A. Yes, it is.

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

EXAMINER CATANACH: Mr. Gill is so qualified.

Q. (BY MR. KELLAHIN) Mr. Gill, to refresh the Examiner's recollection about your project, let me have you turn to what we've marked as Exhibit No. 1. Using that display, help us find the boundary of your project and how you've identified it on that exhibit.

A. Okay. Exhibit 1 is a map showing the area in Eddy County where the Red Lake Unit is located. We've highlighted the unit itself in yellow. And also highlighted on the map are several other Penrose Sand units which have essentially been completed as far as waterflooding in the Penrose Sand.

The purpose of this plat is primarily to show that these other units, which are essentially completed, have all used pressures of considerably in excess of our current pressure limitations of 900 pounds ranging as high as 1800 pounds for the Vintage East High Lonesome Penrose Sand Unit.

These projects have all been successful

in the secondary recovery of oil. Most of them exceeding a one-to-one, secondary-to-primary recovery ratio. The unit that immediately offsets our Red Lake Unit to the south, which is highlighted in red, recovered 1.3-to-1, secondary-to-primary ratio. That particular unit had a maximum pressure during its life of 1450 pounds on the injection wells.

Q. In studying your project and comparing it to other projects in this area, are we looking at the same geologic formations that are being flooded by these various operations?

A. Yes. It is the Penrose Sand, which is a portion of the Queen Formation.

Q. Have you determined whether or not these other projects have been successful in terms of secondary recovery of oil?

A. Yes. I would point out also that I visited with the Oil Conservation Division office in Artesia concerning these other projects which have all, as I pointed out, used higher pressures. And they indicated that there have been no problems associated with these higher pressures.

Q. Let's turn specifically to your

project. This Examiner approved for the Division Director to sign an order entered on March 12, 1991. It's R-9453, which initially approved the project with the .2 PSI per foot of depth surface limitation. Are you familiar with that order?

A. Yes.

Q. That's the order that you've operated under?

A. Yes.

Q. Subsequent to the entry of the order, what did you do?

A. Well, we installed the necessary facilities and put in a waterflood plant, put the unit in operation, and have been in operation and injecting since June of 1991, approximately a year now.

Q. At the .2 PSI per foot of depth, what would the surface pressure limitation have been?

A. Approximately 350 pounds per well.

Q. Were you able to obtain an effective and efficient response from the flood at that surface pressure limitation?

A. No. And we, after beginning at that pressure limitation pursuant to the conditions of the order, came back and conducted step-rate tests on several of the wells in the unit. I believe it was five that we conducted step-rate tests on. And at that time were granted pressure limitation, which is our current limitation, of 900 pounds.

Q. Let's turn now to Exhibit No. 2. Would you identify and describe that display?

A. Okay. Exhibit 2 is a plat of the Red Lake Unit itself. And on this plat I have identified several wells in which we have conducted some tests. First, I will point out that there are twelve producing wells and thirteen injection wells. The injection wells are indicated by the blue triangles.

We also conducted several tests in reference to this application. The red outline around well No. 23 is indicative of the well that we ran a full-wave sonic log in for determining rock properties for the formations above and below the Penrose.

Also the green hexagons indicate wells in which we ran injection profiles at the requested pressure of 1500 pounds. The yellow circles indicate wells in which we ran bottom-hole pressure bombs and conducted pressure fall-off and pump tests.

And I would point out that the green hexagon wells, of those wells we have tried to pick a cross-section of the unit as far as the type of wells. Well No. 2 would be considered a fairly mediocre to below average well. Well No. 10 would be considered an above average injection well in that it takes better volumes at lower pressures. Well No. 21 again is below average.

Well No. 24 is one of the three tightest wells in the unit. We were attempting with this data that we gathered to get a good cross-section indicative of all the wells in the unit.

Q. Do you have an opinion as to whether or not you can obtain an effective and efficient waterflood response at the current pressure limitation at the surface of the 900 pounds?

A. No, we cannot.

Q. What are some of the reasons for that opinion?

A. Well, I'll discuss that more on Exhibit 3. But basically the reason is we are unable to inject sufficient amounts of water into the injection wells at the limitation of 900 pounds due to the fairly tight nature of the Penrose Sand in this area in order to effectively flood it in a period of time in which some economic justification can be had.

Q. If the pressure limitation of 900 pounds is not increased, what will happen to the project?

A. The project will most likely be abandoned.

Q. What has been the current expenditure of your company for this waterflood project?

A. In excess of $600,000.

Q. What is the approximate volume of estimated recoverable secondary oil that can be recovered from this project if an effective and efficient response can be obtained?

A. 550,000 barrels.

Q. What is the pressure surface limitation that you're seeking for your project?

A. 1500 pounds.

Q. In your opinion will that provide you sufficient operational flexibility in order to continue injecting water into these injection wells and continue with your expectation of recovering this secondary oil?

A. Yes, I believe it will.

Q. When we look at the unit boundary on Exhibit No. 2, how was that identified for us?

A. You mean on the plat itself?

Q. Yes, sir.

A. It's a heavy dashed line that surrounds the area indicated by the green highlighted wells and the blue highlighted wells.

Q. Let me show you a copy of Exhibit No. 14, Mr. Gill, in which there is attached return receipt cards. Would you look at that list for me and tell me what those names indicate in terms of their interests or how they might be affected by your project?

A. Okay. These are the offset operators and the surface owners surrounding and including the unit area.

Q. The surface owners are for those owners at the specific injection well locations?

A. Yes.

Q. And the offset operators are those operators within a half-mile radius of each injection well?

A. That is correct.

Q. Are these the same parties that you

notified when you sought approval of your original waterflood project?

A. They are with the exception of a couple of cases where one company has been bought out by another.

Q. So you've updated your notice list?

A. That is correct.

Q. Based upon that notification have you received any objection from any of those parties to increasing your pressure limitation to the 1500 pounds?

A. No, sir.

Q. Let's turn to Exhibit No. 3. Would you identify that?

A. Exhibit 3 is a production curve for the Red Lake Unit. The red highlighted portion of the curve is the oil production since the inception of injection, which was in June of 1991.

And I would point out that the production increase in August of 1991 was due to some reworking of producing wells, which we did at that time right after we commenced injection, and is not due to water injection and that we have at this time seen no response to water injection.

On the top of the curve I've shown highlighted in blue the daily water injection, daily average water injection. I would point out that, as we discussed earlier, we started out with the 2/10 of a PSI limitation, which was about 350 pounds.

In September of 91 was when we conducted our step-rate tests and received approval to increase our pressure to 900 pounds, at which point our daily water injection volume increased to approximately 2100 barrels per day. And since that time has declined each month due to the partial repressurization of the formation to a current rate of about 1,000 barrels of water per day, on average approximately 77 barrels of water per day per injection well.

And I would point out that our original projection and our original economics for this project were predicated on being able to inject an adequate amount of water into the formation, which at that time we estimated at 200 barrels of water per day. We're considerably less than half of that at this point.

The project will fail under the current

conditions because the injection volumes are insufficient to repressure the formation and effectively flood in a sufficient time period in order to economically recover the oil.

And again projected reserves for this project are 550,000 barrels.

Q. Identify for me Exhibit No. 4.

A. Exhibit 4 is just tabular production and injection information that's shown on the decline curve. And I would point out from this exhibit we have a cumulative injection of close to 500,000 barrels.

The voidage of the reservoir prior to the beginning of injection was approximately 1.2 million barrels. And in order to be able to effectively flood the formation, we have to replace that voidage and then from that point on inject an amount equal to withdrawals in order to effectively recover the oil that remains in the reservoir. And we're less than halfway there and declining each month due to the pressure limitation.

Q. Let's turn to a description of the geology and to some of the characteristics you've discovered about the reservoir. To begin that discussion let me have you identify for us Exhibit No. 5.

A. Exhibit 5 is just a type log on Red Lake Unit Well No. 23, which was highlighted in red on Exhibit 2. It's a density neutron log. The purpose was simply to show the Queen Interval and the Penrose Sand, which is within the Queen, is highlighted on yellow on this type log.

The section above the Penrose consists of approximately 240 feet of layers of dense anhydritic dolomites and shales. The section below the Penrose consists of approximately 430 feet of the same anhydritic dolomites and shales and a few thin tight sands.

Q. When we look at this type log, is it characteristic of the reservoir conditions geologically for the other wells in the flood project?

A. Yes.

Q. Do you see a substantial change in either the thickness -- well, let's start off with the thickness of the Queen --

A. No.

Q. -- as we move within the project area?

A. No. Very little change.

Q. The Queen is one of the members included within the East Red Lake-Queen-Grayburg Pool?
A. That's correct.
Q. Within the Queen Interval itself, are there any other contributing hydrocarbon zones other than this Penrose Sand?
A. No, there are not.
Q. Let me have you turn to the cross-sections. Let's turn to 6, which is the north-south cross-section and have you show us the distribution of the Penrose Sand as we move north and south through the unit.
A. Well, basically these cross-sections are intended just to show the continuity of the Penrose Sand throughout the unit and the continuity of the zones above and below the Queen section, which I mentioned on the type log throughout the unit.
Q. Do you continue to conclude that you have adequate quality and sufficient uniformity of the Penrose member to make this a successful floodable formation provided you can have a sufficient surface pressure limitation?
A. Yes, sir.

Q. And for the record then refer to Exhibit No. 7 and describe the east-west geology as it's displayed there.

A. Again Exhibit 7 is intended to show the continuity of the Penrose in the sections above and below it throughout the unit area.

Q. Having come to the conclusion that 900 pounds is insufficient to allow you to continue the project, what then did you do?

A. We conducted some reevaluation of the reservoir engineering in the unit. At that time I studied the withdrawals and the amount of injection that we were putting into it.

And it was at that time that I reached the conclusion that at the current rates of injection we were not going to have a project that was economically feasible to continue. We are currently operating at below economic break-even point. The operations exceed the revenue from the oil at this point.

So based on those studies I convinced the investors and the owners of the company that we needed to conduct a study and employ a consultant and come back and try to get an increase in our pressure restriction in order to recover on an economic basis the secondary reserves in this area.

Q. Let me ask you how you went about selecting a consulting firm.

A. I visited with several people about who would be best qualified to do a study in regards to fracture propagation and what exactly would happen in this formation in the event we did put a certain pressure on it because obviously if we inject at a pressure that's high enough that we're going to inject out of zone or go somewhere besides the Penrose Interval, which we're trying to flood, that would also cause the project to fail.

Q. What engineering consulting firm did you select?

A. S. A. Holditch & Associates is a firm out of College Station, which Brad is with, that I was told were the experts in the field of fracture design. And they literally wrote the book on fracturing and design of fracture software for treating companies and that sort of thing. And they've extensively done research in the area of fracture design and exactly what happens when you fracture a well.

Q. What did you ask them to do for you?

A. To conduct a study in the Red Lake Unit to determine what pressure we could safely inject at and which would be above our parting pressure and still stay contained within the Penrose Interval.

Q. Did you specifically request the consulting firm to examine the feasibility of utilizing 1500 pounds as a surface pressure limitation and under that limitation see what happens to the propagation of fractures?

A. Yes, I did. And that was based on the information from the offset units which had used similar pressures.

Q. What data and information did you supply Mr. Robinson so that he could undertake his study?

A. Okay. We, referring back to Exhibit 2, conducted several tests and also supplied the Holditch firm with initial treatment information, pressure data from initial treatments of wells in this area and outside this area, well data, completion data on the wells.

We conducted several tests including the full-wave sonic log and the pressure fall-off tests, which were primarily used for their studies.

Q. Did you work in connection with Mr. Robinson to determine that you were providing him with a sufficient database of information from which then he could make his study and derive his engineering conclusions?

A. Yes, I did.

Q. Did you subsequently obtain from the Division approval to run additional injectivity tests within the waterflood project at rates in excess of the 900 pounds surface limitation?

A. That is correct. I visited with the Artesia OCD office concerning this. And they advised that I needed to submit a written request to do that, which I did. And Johnny Robinson, I believe, corresponded with David concerning that written request and David called me. And after we discussed it, David gave us permission to conduct a week-long test at 1500 pounds in order to determine the necessary data for this study.

Q. And you did in fact conduct that test and submit that data to Mr. Robinson for his analysis?

A. That is correct.

Q. Let me have you turn, sir, to what is marked as Exhibits 8, 9, 10, and 11 and have you identify those exhibits for us.

A. Okay. Exhibits 8 through 11 are injectivity profiles which are indicated on Exhibit 2 highlighted by the green hexagons. The purpose of these was to actually pump into these injection wells at 1500 pounds with a logging tool in the hole and inject some radioactive material above the pay zone and basically follow it down the wellbore and see where it went out.

And if you'll turn to -- I'm just going to highlight one of these for you, or we can look at all of them if you'd like, but let's look at Exhibit 9. If you'll turn to the portion of it fairly close to the top where the presentation is shown, the perforated interval in this particular well, which is Red Lake Unit No. 10, is shown by the little arrows beginning at 1609 and going down to 1634.

And the presentation simply shows by the crosshatching next to the perforated interval where the injection interval was at 1500 pounds. And there is no indication on this particular well or any of the other three wells that the injected fluid went up or down. In fact, it went into the perforations and went away into the perforated interval.

And obviously if adding injecting at this pressure was going to cause a problem in terms of the cement bonding or the actual operational condition of the well, there's a possibility that we might have seen some channeling or some indication of a problem in regards to that pressure, which we did not in these four wells.

And I feel that these are representative of all the injection wells in the unit and that there will be no problems associated with injecting at 1500 pounds.

Q. What do you mean by no problems associated with injection at 1500 pounds surface pressure limitation?

A. Well, specifically breakdown of the cement sheath around the casing which could cause channeling of fluid up the hole into other zones which we're not trying to flood, that type of problem.

Q. Where is the deepest occurrence of any known freshwater sources in this area?

A. I believe it's around 80 feet.

Q. In terms of executing your operations within the waterflood project, are you satisfied that increasing the pressure limitation to 1500 pounds is not going to place at risk any shallower freshwater sources?

A. Yes, absolutely.

Q. In addition, are you satisfied from what you know and from the studies of all the data available to you that increasing the surface pressure limitation will cause the injected fluids to remain contained within the vertical limits of the Queen Formation?

A. Yes. And, of course, Brad will comment at length on that. But that was the purpose of our study, was to be certain that at 1500 pounds we would remain contained within the Penrose Formation.

Q. And as we've already seen, the Penrose Formation is the only productive formation or zone we have within the Queen Formation?

A. That's correct.

MR. KELLAHIN: That concludes my examination of Mr. Gill. We move the introduction of Exhibits 1 through 11.

EXAMINER CATANACH: Exhibits 1 through 9 will be admitted as evidence.

MR. KELLAHIN: I'm sorry. It should be 1 through 11, Mr. Examiner.

EXAMINER CATANACH: 1 through 11 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Gill, was the engineering study that was performed, was that based solely on the profile logs?

A. No, sir.

Q. It was based on some other data?

A. Yes. Considerable other data including the pressure fall-off tests and some pressure pump-in tests, which are indicated by the yellow circles on the Exhibit 2, and also some historical information such as treatment information from initial treatments on the wells. And Brad will refer to that at length in his presentation.

We also ran the full-wave sonic log in well No. 23 which was for the purpose of gathering rock properties of the formations above and below the Penrose.

Q. What is your understanding to be the radius of investigation on when you run one of these profile logs?

A. Somewhere in the neighborhood of 18 inches beyond the wellbore. So basically this is just telling us that it's leaving in the right place and that it's not channeling up the borehole -- up or down the borehole.

Q. You believe the cement integrity in your other injection wells is adequate to contain the fluid?

A. Yes, sir, I do.

Q. The four profile logs that were run, they all indicated the same thing?

A. Yes, sir. No indication of any channeling up or down. Always the fluid was all leaving in the Penrose perforations.

Q. Mr. Gill, what would you estimate to be a reasonable time period to see a response to waterflood operations?

A. The original projection called for approximately a year. So as of now we should have been seeing a significant response by a year. The original projection was based on an estimated average rate of 200 barrels of water per day per injection well, which was predicated on the historical performance of the Red Lake Unit which offsets us to the south.

Q. Is there a specific volume that you hope to accomplish to inject into each of these wells?

A. My target rate is 300 barrels per day per well.

Q. With regards to the other projects you showed on Exhibit No. 1, are these projects now in their twilight?

A. That's correct, yes.

Q. And these were probably approved quite a while back when there was no pressure limitation?

A. That's also correct. In fact, I think injection has ceased on all of these projects at this point.

Q. You said you consulted with the Artesia District Office. Did they indicate to you that there had been any type of problem in any of these projects in terms of water out of zone or water flows of any kind?

A. None whatsoever.

Q. So, as far as you know, the water

injected at these pressures was confined to the Penrose?

A. Yes. And I think the success of those projects would also be evidence to that fact because, if they were in fact injecting water out of zone, they would not have recovered the secondary oil.

EXAMINER CATANACH: I believe that's all I have of the witness. He may be excused.

MR. STOVALL: You're assuming I didn't have any questions?

EXAMINER CATANACH: Well, I turned to you and you didn't say anything. You weren't here for it anyway.

MR. KELLAHIN: Mr. Examiner, at this time I'd like to call Mr. Brad Robinson.

BRADLEY M. ROBINSON

Having been duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. KELLAHIN:

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

A. Bradley M. Robinson. I'm vice president at S. A. Holditch & Associates.

Q. What is it that you do, Mr. Robinson?
A. I'm a petroleum engineer. Our firm consults on petroleum engineering projects, all types, but primarily involving low permeability formations and the hydraulic fracturing of those formations. We design the fracture treatment. We'll analyze the data. And we also provide field supervision of all types of hydraulic fracture treatments.
Q. What were you specifically retained to do by Beach Exploration?
A. They asked me to conduct a study to determine if injection into this waterflood at a surface pressure of 1500 PSI would create or cause hydraulic fractures to propagate out of zone and pose any potential problems involving the injection of water out of zone.
Q. Is that a request for which you're qualified to undertake a study and reach conclusions?
A. Yes.
Q. What is your educational background, Mr. Robinson?
A. I graduated with a bachelor's degree in petroleum engineering from Texas A & M in 1977.

I went to work for Marathon Oil Company in Midland in their production office. Worked about two years as a production engineer for Marathon and was transferred over to the reservoir engineering department where I worked for about another eight months.

I left Marathon and went to work for S. A. Holditch & Associates in October of 79. I've been working at Holditch ever since. While I was at the firm in College Station, I was able to go back to Texas A & M and earn my master's degree in petroleum engineering.

Q. In what year, sir?

A. 1985.

Q. Is the request that Beach made of you to provide an engineering study on this particular pressure issue one in which you have performed before for others?

A. This is probably a little bit different. We do perform waterflood studies quite often, more from the reservoir engineering aspects. We've modeled waterfloods. We've determined optimum injection rates, waterflood injector patterns, producing patterns, and so forth.

So actually I've never been asked to look at it in this light, but it's exactly the same principle as we are involved in every day as far as the propagation of fractures due to fluid injection. So there's really no difference other than it's for flooding an oil reservoir as opposed to trying to pump sand in, which is the normal fracturing procedure, in an effort to stimulate the reservoir.

Q. Were you able to obtain data which you considered to be sufficient in order to undertake this study?

A. Yes. Yes, Beach had quite a bit of data available to conduct a study. And we made several recommendations as far as additional tests that they should conduct to help us quantify and determine for sure that the higher injection pressure would be safe.

Q. Based upon that information, you've completed your study and now have conclusions with regards to this issue?

A. Yes.

MR. KELLAHIN: Do you need a minute?

MR. STOVALL: No. Go ahead.

MR. KELLAHIN: We tender Mr. Robinson

as an expert petroleum engineer with special expertise in fractured reservoirs.

EXAMINER CATANACH: Mr. Robinson is so qualified.

Q. (BY MR. KELLAHIN) Mr. Robinson, before we go to your specific study, let me have you identify for the record what we've marked as Beach Exhibit No. 12.

A. Okay. That's commonly referred to as a frac-height log or fractural height log. This particular log was run by Halliburton Logging Services. This log was run on the Red Lake Unit No. 23.

Q. Is that part of the data that you've examined in your study?

A. Yes. As a matter of fact, this log was run specifically at our request by Beach.

Q. Before we talk about the study specifically, tell us generally how you select a methodology or a way to satisfy yourself as an expert that you're approaching a solution in the correct way that's going to get you a reliable conclusion that you can state with engineering confidence is going to be a safe pressure limitation for the project.

A. Well, with any type of study, there are just certain types of data that you need to be able to come to conclusions that you're looking for. And over the years -- our firm has been in business about, oh, 15 years, I guess. I've worked for them 13 of those 15 years. For certain projects you just develop an experience level at the types of data that you need to answer the questions that you're trying to answer.

And when it comes to hydraulic fracturing, there are certain formation properties that you need to know. And you can obtain those data either from cores or logs. There is pressure information that involves the injection of water or jell or whatever you're trying to inject, the pressure that occurs while you're performing that operation.

And so you just basically develop a shopping list of the types of information you need before -- or in order to conduct your study. And so when I first visited with Hal, I listed the types of information I thought we were going to need to be able to determine what types of fracture propagation they may see with a 1500

PSI surface pressure.

Q. Were you satisfied then that you ultimately received sufficient data so that you could properly execute the purposes of the study?

A. Yes.

Q. Let me have you identify for us what is marked as Exhibit No. 13.

A. This is basically the results including diagrams and data of our study. I've prepared it in the form of a series of exhibits. Normally in a study of this type we'll have similar type diagrams and figures, but we'll have a lot of text, discussion to go along with it. We haven't prepared that for Beach yet. But this is all the pertinent results, figures, and information that's formed the basis for my conclusions.

Q. All right. Present your report to us.

A. Okay. On page 1 we always like to identify the purpose of the study whenever we're doing it. And the general purpose was to determine if increasing the maximum allowable surface injection pressure to 1500 PSI would cause the hydraulic fractures in the injection wells to grow out of zone.

Q. Let's define "grow out of zone" while we're at that point.

A. Grow out of the Queen interval and propagate into some other undesirable formations.

To approach the problem or to try and solve the problem, we analyze the existing fracture treatment data and step-rate injection data on these wells. We then recommended to Beach that they conduct injection fall-off tests and then we analyzed those tests.

We determined the vertical stress profile for zones above and below the Penrose. And that is probably one of the most critical pieces of information that you can have when you're trying to study the growth or fractures out of zone.

And then we used our fracture simulator to predict the fracture dimensions with the increased water injection pressure, sort of a "what if" case.

Q. Based upon that study, would you summarize for us the results?

A. Yes. The results are summarized on page 2. The data analysis supports the presence of horizontal fractures in the Red Lake Unit.

These fractures -- I'll show you an illustration in a minute -- grow horizontally as opposed to vertically.

And given that condition there will be no problem at all of high growth out of the Penrose, which is the second point there on the results. Height growth would not be a problem with horizontal fractures.

There is some evidence to suggest that vertical fractures may be present. It's weak, but it's there and I'm not going to try and hide it. If they are present, we found that sufficient stress contrast exists to contain the fracture height growth in our opinion.

Q. Before we leave that point, let me have you amplify it. Based upon limited information, there is a possible suggestion of vertical fracture growth?

A. Right.

Q. The stress contrasts are representative in formation barriers above and below the Penrose?

A. That's true.

Q. And contained within the Queen Formation?

A. That's right. The barriers are still within the Queen.

Q. So you have concluded that if there is any potential for vertical fracture growth, those vertical fractures are not going to propagate outside of the principal flood zone, which is the Penrose?

A. Exactly.

Q. What's the last point?

A. The last point is that in either case, either for horizontal or vertical fractures, you will create an equilibrium condition while you're injecting water where the amount of water that you inject equals the amount of water that's leaking off. That is your primary flood, of course, the leak-off of the water into the zone.

And when that occurs, the fracture is going to stop growing. That's called an equilibrium growth condition. There may be some propagation of the fracture initially at this higher rate. That's not unexpected, but it will eventually stop growing when this equilibrium condition exists.

Q. Within your particular expertise in analyzing reservoir fracturing, you have a vocabulary that uses terminology that either I, as a layman, or other engineers might define differently. And so that we're all using your definitions and clearly understand that vocabulary, I've asked you to compile a series of displays and have you go through with us then to make sure we understand the terms that you're going to use when we discuss the actual data used for the project. Would you start that for me --

A. Sure.

Q. -- with page 3?

A. Yes. On page 3, starting there, I've drawn up several illustrations to show the different types of fractures that we're going to be talking about today and to illustrate some of the terminology that I'll be using.

One of the types of fractures obviously that we'll be talking about are vertical fractures. I've drawn a side view of a fracture there. If you were sitting out away from the wellbore looking at it, you would see two wings extending from both sides within the sand.

If you were at the surface and able to look down at the top of the fracture, you would see a view much like is shown there on the bottom of the page. We would see the width of the fracture. I've got a couple of arrows on that figure with the Greek symbol "theta" sub-H.

Fractures propagate against the minimum stress in the rock. They open against the least stress. I mean, that's just the mechanics of nature. That stress for vertical fractures is in a horizontal direction, or lateral direction in the rock, so that the fracture can open up, the width against that minimum stress. And that's shown on that top view down at the bottom of the page.

We'll also be talking about horizontal fractures. And those are just the opposite of vertical fractures in that they propagate out laterally into the formation. The side view that you would be looking at there at the top of the page shows the width of the fracture.

And the top view, down at the bottom of the page, shows the extent or radius of the fracture. Looks like a big pancake growing out into the formation.

Referring back up to the side view at the top, again the stress, "theta" sub-V, that the fracture opens against is the overburden of the earth. The vertical overburden stress is what we call that. And that's usually about 1 PSI per foot, sometimes as high as 1.1 PSI per foot. But that's the stress of the earth due to the density of the rock layers that are sitting on top of the earth.

Q. Having defined for us the horizontal and vertical fracture terminology, you have also told me about fracture containment.

A. Right.

Q. When you use fracture containment, what does that mean?

A. Well, that's illustrated on the next page. When you have vertical fractures, what you're concerned about is how tall those fractures grow. Again they are propagating up and down.

This illustration shows a sand with a fracture created in it. Above and below it are what we call barrier rocks. Now, the little block diagram towards the left that's labeled "stress," that's increasing to the right, that shows the relationship of the sand to the barrier rocks in terms of the stress.

The stress in the sand itself when it

is much, much less than the stress in the barriers represented by the symbol "theta" sub-B, then you have fracture containment. And that's noted there at the bottom of the page. That containment exists when the stress in the sand is much, much less than the stress in the barriers.

Q. As part of the study then, you developed data that will give you values so that you can determine the stress in the barrier as well as in the sand?

A. Right. We get that information from the frac-height logs. And this is a very simplified case, a simple three-letter case. You've got a sand sitting in between two barrier rocks. And of course in real life situations, you have multiple layers of rock, and each one of them have different properties. And I'll show you the actual data from the frac-height log later.

But this serves to illustrate that a certain value of stress in the sand, if it's sufficiently lower than the barriers above and below you, then that fracture will stay contained.

Q. Let's turn to have you define for us

what you mean when you talk about fracturing pressures.

A. This just illustrates when I refer to injection pressures or something like that, all of those pressures mean something underneath the ground.

Starting at the tip of the fracture, where I've got the symbol P_{ext}, that stands for the extension pressure. That's the pressure out at the crack tip. That's what driving the fracture and causing it to grow. That is either greater than or equal to the stress in the sand. It has to be at least that much if not more to be able to drive the fracture through the rock.

Down the fracture is a friction term. You can think of it in terms of trying to pump water down a pipeline. There will be friction built up in that pipeline. And it's a function of the length. Same thing happens in hydraulic fractures. You build up friction in them as you're trying to pump fluid down.

Then you also have a perforation term. You have pressure drop through the perforations that you have to take into account. And all those things added up equal to the wellbore pressure, which that's the only thing we can measure. We can't go out in the fracture and measure the pressure out there at the tip or halfway down. We can only measure the pressure in the wellbore.

So that's why it's important to understand all these terms. And we have ways to estimate what they are.

Q. Mr. Catanach asked Mr. Gill a question a while ago about the radius of investigation under the injectivity profile, and I think Mr. Gill said it's about 18 inches or give or take a few?

A. Right.

Q. Do you have a way to analyze the effects beyond the near wellbore condition so that we can determine with a reasonable engineering probability the lateral and horizontal distance of these fractures?

A. Yeah. We've built a fracture simulator that takes into account all of the properties of the layers, specifically and most importantly the stress in each one of these layers. And it calculates all of these pressures.

And if the pressure in that fracture

exceeds the stress of the layer above, then the simulator will predict that it busts through it essentially. And so it keeps track of all the pressures and where they are in the fracture, and then it will predict if the fracture grows through the various layers based on their rock properties and stress values.

Q. To cut to the conclusion, what did your modeling results show you for this project?

A. Well, it showed that it would stay contained to the Penrose interval because of the stress barriers above and below.

Q. That was only one of the ways that you reached the conclusion that the fractures would stay confined to the Penrose. You had other ways to reach that conclusion?

A. Yes, we did. There's a lot of supporting data. I mean, you really don't even have to do the modeling to know when you look at the fracturing data, the step-rate test data, the frac-height log, there's just some common sense information there that we can look at and study and determine. Like I said, in our opinion the fractures are horizontal. I mean, that data to me is fairly clear.

So when we're talking about vertical fractures and growth out of zone, that's only for that small case where it might exist. And that's why -- that's the critical case. The vertical height growth, that's the important one. That's why we spent most of our time and effort trying to look at that issue.

Again I strongly believe there are horizontal fractures here. And if that's the case, there's not even an issue related to that.

Q. Before we get into the specifics of the study, the last display is found on page 7. What does this represent?

A. Well, it's the same type of picture we had on the previous page except this is for a horizontal fracture case. It just shows that the same terms are exactly -- exactly apply to the horizontal fracture case.

The only difference is the extension pressure out at the tip is greater than or equal to that overburden stress, theta sub-V, which is basically the stress due to the thickness of the layers of rock on top of the zone.

Q. Let's turn to the next chapter. On page 8 we talk about the step-rate injection

fracturing data?
A. Uh-huh.
Q. This is the data supplied to you by the operator from the post-order step-rate tests that Mr. Gill conducted in order to obtain from the Division the current 900 pound surface pressure limitation?
A. Right.
Q. Have you taken that study or that data and re-analyzed each of those step-rate tests?
A. Yes, we did. And the previous results are summarized on the first table.
Q. Let's look at that.
A. These --
Q. Page 9?
A. Page 9. These aren't our results. These are the previous results which are summarized with the five graphs shown behind there. All I've done is just taken all that information and summarized it on a single table.
Q. Having taken that data, re-analyzed it, and examined it, do you reach the same conclusions as shown on page 9?
A. No, I don't. I really feel like on several of the wells that they really never got

to the parting pressure and specifically Wells 5, 9, and 25. The reason I say that, and I'll show you in a minute, but look at the column labeled "fracture gradient" --

Q. On page 9 still?

A. On page 9, yes. -- labeled for Wells 5, 9, and 25. Fracture gradients for those three wells are all about 0.85 to 0.88 PSI per foot. The other two wells, No. 14 and 22, are over 1 PSI per foot.

The fracture gradient for a horizontal fracture that I would expect is in excess of 1 PSI per foot. And those two wells certainly have it. The other two are less than 1 PSI per foot. So that makes me think that they never really opened the fracture while they were conducting the step-rate test; that they shut down the test too soon so they never saw the parting pressure.

So I would disagree with those values, and I'll show you why here in a minute.

Q. What effect does that have ultimately on the appropriate pressure to apply to have an effective response in the waterflood project?

A. Well, if they never exceeded the parting pressure, then the pressure resulting from these tests would be too low. The 900 PSI was well below the parting pressure of these reservoirs.

Q. Let's have you go to the point in the study and show us how you've re-analyzed the step-rate tests.

A. Okay. Starting on page 15 are our data. We've regenerated the plots and plotted them up on the same scale, and we've reviewed the test. Honestly I really don't think that the data on pages 15, 16, and 19 indicate that a fracture was opened.

I mean, we've looked at dozens of step-rate tests and hundreds of what we call micro-frac tests, which are designed to measure this exact very thing, the fracture opening pressure. A little different procedure, but the purpose of the test is exactly the same.

And there are certain characteristics that you just learn to look for in the character of these pressure curves that tell you the fracture is open. And I just didn't see it on those three wells that I mentioned earlier where the fracture gradient was less than 1.

Q. Let me have you turn to page 20, and

let's use that display to have you help us understand as an expert at what point in that curve you finally conclude that you've reached a parting pressure.

A. Okay. We've taken all the tests and plotted them on the exact same graph. The top two curves labeled RLU No. 14 and RLU No. 22 are those two tests that I feel like a parting pressure was measured.

As you can see, those are substantially higher than the other three wells. And also they exhibit to me a change in the pressure increase. What we look for is a deflection point along the curve.

That indicated to me that the fracture was opened at some point along the top of the curve. That's where we look for the pressure to really bend over sharply.

Q. In analyzing this do you look for the first point in which the slope of the curve changes?

A. No. You really look for where it flattens over because that's where the fracture is open and has started to grow again, completely open. You can start getting some leak-off. And what we call a transition zone is that things are rolling over. But sometimes you look for it where it's completely flat.

A typical technique and one we used to re-analyze these tests is to take two straight lines and draw them through the data and pick an inflection point. That gives you a more conservative answer and the reason why we chose it.

But actually there's -- some people believe that it's the point at which it actually goes flat, the pressure curve.

Q. Summarize for us your conclusions about the step-rate test as you've shown them on page 21.

A. Number one, first of all, we feel very strongly that horizontal fractures exist in the Red Lake Unit. And it's based on the measured parting pressures that exceed 1 PSI per foot. And we feel like that fractures were just not reopened on Wells 5, 9, and 25; that the character of the step-rate tests was such that it just never got there. The pressures were increasing and never really showed that character that we look for.

Or we have another conclusion there, which we again feel like horizontal fractures exist on 14 and 22. Now, there's a possibility that if a fracture was open, that it would probably be a vertical fracture on Wells 5, 9, and 25.

And the original values for fracture gradient, the .85 PSI per foot, the .88 PSI per foot, those original values are typical of vertical fractures. I don't agree with them, but because somebody else came up with those answers, it's a possibility.

Q. Turn to page 22.

A. This is a summary of all the injection and fracture treatment data that we reviewed in our study. It lists all the wells in the first column there. They reference Kelly Bushing depth, the perforated interval, and the depth from the from the surface. And we've also calculated the perforation level with reference to the sea level.

We've listed the values for parting pressure measured from the step-rate tests. Prior to many of the fracture treatments, Beach Exploration performed acid breakdown treatments on their wells, and we also reviewed those data. As you can see, in most cases those fracture gradients from the acid treatments were on the order of 1 PSI per foot.

Q. Does this information support your conclusion?

A. Yes.

Q. How?

A. Well, again the gradients of around 1 PSI per foot indicate to me that the fractures are trying to lift up the earth, the overburden, as opposed to push apart a rock. And so when you see gradients on the order of 1 to 1.1 PSI per foot, that's typical of horizontal fractures.

Q. What would be the range of gradients that you would see if they were vertical fractures?

A. I would expect the fracture gradients to be on the order of .7 PSI per foot up to .9 PSI per foot. That's pretty high and you generally only see gradients as high as .9 in geopressured reservoirs, which I don't believe this is. Well, I know it's not.

The last column I think tells the real story. We analyzed the fracture treatments performed on almost every well listed on this page. And in every case the estimated gradient based on those treatments was in excess of 1 PSI per foot.

Q. Let me ask you if you have any comments or opinions about the beginning benchmark the Division used. You know, you saw in this sequence that they start the waterflood limitation pressure at .2 PSI per foot of depth from the surface to the top perforation.

Do you have any comments or opinions about that being the initial standard by which to apply a pressure limitation to waterflood projects?

A. Well, that's a surface pressure. So if I think in terms of downhole, I have to add the hydrostatic head of water, which is .44 PSI per foot. So that gives me a downhole gradient of about .64 PSI per foot.

As I stated, for vertical fractures the expected range of gradients is on the order of .7 to .9. So the limitation used by the Commission of a .64 seems very reasonable in that it's just slightly less than typical values for vertical fractures.

Q. So that remains a good initial starting point when you're just trying to apply a limitation to these projects without going through the intense study that you have for a specific project?

A. Right. I think, given typical fracture gradients for vertical fractures, that's a very good rule of thumb to use.

Q. Let's go to the next step. The next step then is using the step-rate methodology or data to increase that surface pressure limitation up to the point where you have a break-over on the step-rate.

A. Okay. If you had say, for instance, a gradient of .9 or in this case even exceeding 1 PSI per foot, the step-rate tests tell you at what point your fracture does open up. So, you know, it gives you a downhole parting pressure or gradient if you divide it by depth. And then you can see how that compares to the original rule of thumb to see if you could inject at a higher pressure and still be below parting pressure.

Q. For the second level of regulatory control, if you will, being this step-rate process, are you comfortable as an expert in this area that that represents a good regulatory way to increase pressures in projects above the .2 to the next level of injection pressure?

A. Yes. I mean, that is the way to do it as far as I'm concerned.

Q. After that to get to the point where we are at this hearing, for you as an expert what comfort level do you need, what kind of data makes you satisfied that you then can support the kind of conclusions and work you've made for this study?

A. Well, of course, we try to obtain step-rate tests. In this case there were already tests performed on five wells. We also like to look at injectivity tests to measure the pressure and the rate at the limit that you're trying to -- that you're requesting. We want to see how the pressure behaves while you're injecting at that value.

There are certain characteristics that we look for to tell us whether the fracture is growing out of zone or whether it's staying in zone. And we recommended these tests to Beach. And that's the tests, the injectivity tests they ran about a week ago, I believe, where they contacted the Commission and requested the higher pressure.

But we look at those, those pressure profiles. And we -- I mean, there's just certain qualitative things you can tell just by looking from experience. And then we can also take our simulators if we want to and try to history match those pressure profiles, very similar to what reservoir modelers do when they're matching production or pressure history. So there's a lot of ways we can use that data.

Q. You've undertaken that then for this project, and what have you presented for us to support those conclusions?

A. Yes, I have. And I've got that shown on the next few sections. I'd like to make one more point regarding the .2. I think it's very adequate and certainly is a very reasonable value to use for vertical fractures.

For horizontal fractures when we have sufficient data to justify that horizontal fractures exist, .2 would be a lot lower than you would actually need, again because the fracture gradients associated with horizontal fractures are almost always -- well, they are always in excess of 1 PSI per foot.

Q. I understand your explanation. Your original answer was within the context of my question, which is when you don't have that information, you're just starting your project and you don't have the subsequent information that Beach has developed, then an initial generic, if you will, starting point for a pressure limitation is .2?

A. It's a great place to start.

Q. Show us where we finish now.

A. Okay. We asked Beach to run some injection fall-off tests for us. The primary purpose of these tests were to determine the permeability of the reservoir, which is very important when you're trying to analyze hydraulic fractures. It would also be very important for Beach to have this information for the reservoir part of their study.

But they ran two fall-off tests: One was on well No. 21, a second test on well No. 10. The results from our analysis are shown in a graphical presentation on pages 24 and 25. These are type curves. The nice thing about hydraulic fracturing work is it's very similar to reservoir engineering work in terms of how you analyze pressure behavior.

And these injection fall-off tests we can analyze with type curves that have been developed for reservoir engineering applications. And these particular type curves were generated for horizontal fractures. And, as you can see, I was able to successfully match the pressure fall-off data to these type curves for horizontal fractures.

Q. For my information, the type curve is the straight line; the data points on pressure are the little dots?

A. That's exactly right.

Q. And this satisfies you that you've got a good match?

A. These are excellent matches. I'll mention -- and I have the data with with me -- I was able to get a match of the fall-off data with vertical fracture type curves also, but it wasn't as good. I got the best match with the horizontal fracture type curves of the fall-off data.

So from this we concluded that the permeability is between 1 and 4 millidarcies for these injection wells. The fracture lengths that we calculated were between 130 to 330 feet in length.

And the last point there is that the pressure fall-off data matched both the horizontal and fracture solutions, horizontal and vertical fracture solutions. But our best match was with the horizontal fractured case.

Q. In order to reconfirm your conclusions about the horizontal fracturings existing in the Penrose, as opposed to the vertical fracturing, did you undertake to use the simulation, the fracture simulation to predict fractures for the project?

A. Yes. Yes, that's shown in the next section on page 27. We ran both cases. Again the horizontal fracture case we're not concerned at all with growth out of zone. But if a vertical fracture existed, we would be interested in seeing how much, if any, that it does propagate out of zone.

Q. You ran two cases. Describe them for us.

A. We ran two cases. One was the current conditions where we considered -- and when we're looking at fractures, we usually think in terms of barrels per minute. So these cases were run at .25 barrels per minute, which is equivalent to about 360 barrels a day.

We used a stress profile and properties that were calculated from the Halliburton fracture height log that was run on the RLU No. 23. And we looked at a surface pressure of around 1100 to 1200 PSI. That was based on the injection test data that we were able to obtain where they did measure 1100 to 1200 PSI surface pressure. That's current conditions.

Reservoir pressure is very low. The wells were taking water very well at a 1100 to 1200 PSI range. But as you start to repressurize the reservoir, that stress in the rock is going to go up.

And so we looked at another case, assuming down the road six months or a year down the road when they've repressurized the rock, higher stresses will exist, and therefore the injection pressure will need to be probably around 1500 PSI to maintain that same level of injection. And that's Case 2.

We assumed the higher stress that would

exist in the Penrose would be 1950 PSI due to repressurization. That's equivalent to a surface pressure of 1500 PSI.

Q. When we turn to page 29, describe for us what this shows.

A. What we did is we took the Halliburton presentation and tried to put it in a graph or illustration that was very similar to what we looked at back here on page 5. This is the stress profile. The depth is shown in the vertical track. The stress of each layer within the Queen section is shown across the top, and it increases from left to right. We've shown the perforated interval in the No. 23 well.

And so we see that in the Penrose interval the stress is about 1600 PSI. And above that interval are several layers of rock that have stresses as high as 2500 to 2600 PSI. And so as long as we keep the injection pressure less than those values, the fracture will stay in that Penrose interval. That's the real key.

You don't have to have a model or do any sophisticated fracture simulation. Again it goes down to the basic mechanical principles that the fracture will not grow through zones of higher stress unless you pressurize that fracture to a value that exceeds the stress in those rock layers.

Q. We talked earlier on about the Queen Formation having these barriers, stress barriers, if you will, above and below the Penrose flood zone. When you look at the stress barriers above and below the Penrose, what is that stress value?

A. Well, it's about 2500 PSI or 2600 PSI in one thin layer. And then there's another thicker layer with 2500 PSI. Was that your question?

Q. Yes, sir. And if we're using 1500 pounds as the surface pressure limitation, what stress are you applying to the Penrose in terms of the pressure?

A. Only about 2200 pounds of bottom-hole pressure.

Q. So you have a safety factor, if you will, in terms of pressure of 3- or 400 pounds?

A. Yes. The pressure they're asking for is less than the stress in the boundary or barriers by about 3- or 400 PSI. So there's a margin of safety factor there that they're requesting.

Q. In addition when you look at the location of the Penrose member within the entire Queen interval, there is some vertical distance between the top and the bottom of the Queen that would provide an additional safety factor, would it not?

A. Right. The Penrose is sitting fairly well in the middle of a 4- or 500-thick interval. And the whole interval is just dense limestones and anhydrite, which our experience has been that those generally make good barriers just because of the hardness and denseness of the rock.

You can't always generalize like that because you do need to know the stress in those layers, which you can get normally from logs or actual measurements. But our experience has been that you can generally expect good containment when you have those dense types or rocks above and below you.

Q. Let me have you then go through rather quickly, if you will, the results of the study and give the Examiner a quick reference to each of the following pages, and then let's move to your final conclusion.

A. Okay. Just real quickly, page 30 is a side view of the fracture that our model predicted and how it would look in the Queen or in the Penrose sand after a full year of injection at 360 barrels per day.

We show, using all the input data from the frac-height log and the other data provided by Beach, that the fracture would be essentially contained to the Penrose interval at the small injection rates. That's case 1 that we'll refer to current conditions.

Q. Page 31.

A. Page 31 shows the model-predicted pressures that result from that fracture propagation. And the reason I put that in there is, if you go back to the next two pages -- or go over to the next two pages, 32 and 33, you see the actual measured bottom-hole pressures that were obtained from those injection tests. And they are essentially the same as our model predicts. So we feel very good that the model prediction of pressure is essentially the same as the actual measured value in the field.

Page 34 shows what the model would predict the fractures look like if you increase the injection pressure to 1500 pounds of surface or about 2200 PSI of bottom-hole pressure. Again there's a little bit more height growth, which we'd expect with a higher pressure, but basically the model predicts the fracture would stay in zone.

Q. Give us a quick summary on 36 of this equilibrium on the fracture growth.

A. I added these last two figures just to illustrate that when you're injecting into a fracture the fluid you inject causes the fracture to grow and it continues to extend until such time that the fluid that leaks off is equal to the amount of fluid that you inject. When that occurs, the fracture simply quits growing.

And so I just wanted to illustrate that we normally see and fully expect that equilibrium growth situation will occur at some point in the future. You know, without undertaking a reservoir modeling study, it would be hard to determine when that would occur, but it does occur and we fully expect it to occur. And that's based on just some simple reservoir engineering principles that I've illustrated there on page 37.

Anytime you inject into a well at a pressure, and currently in the Red Lake Unit it's 900 PSI surface or 1600 PSI bottom-hole, you establish a pressure gradient from the injectors over to the producers. And because most of these wells, all of them as far as I know are on pump, the bottom-hole pressure of the producer wells is probably 100 PSI or less until you establish a pressure gradient and an equilibrium condition between those two wells.

If we were to increase the surface pressure to 1500 PSI or 2200 PSI bottom-hole, we would again obtain that pressure equilibrium; it would just be at a higher level. And these curves, they could be straight lines; they could be curves of some sort depending upon the reservoir properties. But this gradient will establish itself and remain fairly constant throughout the well life.

Q. The Examiner is charged with the responsibility to limit waterflood projects so that injection fluids do not cause propagation of fractures so that those fluids would put at risk shallower freshwater zones or cause flooding out of the formation or pools authorized for that flooding.

If that is his charge, does he satisfy it if he grants a surface pressure limitation of 1500 pounds for this project?

A. Yes. Based on our study, which again the results are summarized on the last page, our analysis supports the presence of horizontal fractures in the Penrose sand. So there should not be any problem at all with injection out of zone because all of the fluid will be within the Penrose interval.

Q. Do you see any reason to restrict the project to less than 1500 pounds?

A. Actually you could even go a little higher than that because of the fracture gradients that we see. But we were only asked to look at 1500 PSI, so that's all we studied. But you could actually go up to -- well, there's just no limitation because there will be no growth out of zone.

You could inject at as high a pressure as your pipe would stand basically. And that's the data that Hal presented. The primary purpose of those injection surveys was to look at the mechanical integrity of the wells at 1500 PSI.

And he's satisfied that the wells mechanically can handle that higher pressure. So really you're only limited to the mechanical integrity of the well.

Q. And then finally on the last page, you have given us a written summary of your major conclusions?

A. Right. Again that's the same page that we presented earlier in the report. Again we see evidence that supports the presence of horizontal fractures in this unit. And given that scenario, fracture growth out of zone should not be a problem.

Even if vertical fractures do exist, though, the data that was provided to us and the modeling work that we've done shows that the fracture will stay contained to the primary interval.

And the last point there, regardless of whether it's horizontal or vertical fracture, an equilibrium condition will exist eventually where the amount of water injected equals to the amount of water that's leaked off. And at that point the fracture will simply just quit growing.

MR. KELLAHIN: That concludes our

presentation, Mr. Examiner. We would move the introduction of Exhibits 12, 13, and 14.

EXAMINER CATANACH: Exhibits 12, 13, and 14 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Robinson, you've indicated that you believe there are horizontal fractures in the Penrose?

A. Yes.

Q. At 1100, 1200, 1500 PSI, what in effect are we doing when we inject pressure at that rate? What are we actually doing in the formation?

A. Well, the first thing you do, you fill up the existing fracture that's down there. And all of these wells were hydraulically fractured and propped open with sand on their initial completion. So you fill that fracture up. At that point, the water leaks off in both a vertical direction within the Penrose and out in a lateral direction in the Penrose.

So if the fracture is contained in this pancake shape within the Penrose, that's where all the water goes and then leaks off from there regardless of the pressure. Once you exceed 1 PSI per foot, then you will start opening that fracture up. But again the water leaks off only into the Penrose.

Q. At that high a pressure, are we extending horizontally these fractures?

A. Yes, most likely. And you will until that equalibrium condition again exists.

Q. Are you able to calculate what that equilibrium point is?

A. We could, yes.

Q. I believe you had an opinion on the vertical or the horizontal extent of the fractures?

A. Right.

Q. That was what number?

A. They ranged for the two wells that we looked at between 130 and 330 feet. That's a radius from the wellbore. That circle that we looked at, that pancake on that one illustration, that's the radius of that.

Q. Those are the existing --

A. Yes.

Q. -- Fractures?

A. Yes.

Q. So in fact we may extend those an additional distance?

A. That's true.

Q. Do you have an opinion as to whether injecting at these pressures causes you to lose some efficiency from your waterflood project?

A. No. Honestly I don't have an opinion for this particular case because we haven't looked at it from the reservoir engineering aspects. I've simply looked at it from the hydraulic fracturing and mechanical aspects. I haven't looked at it at all from a reservoir engineering point of view.

MR. GILL: I've got a opinion if you'd like to know mine.

EXAMINER CATANACH: I know yours.

THE WITNESS: But I will say from what I know if you have a formation with a horizontal fracture in it, the more you can inject, the better off you are because you get poorer sweep efficiency with a horizontal fracture.

That may be why they haven't seen as good a reservoir response as they would like to see. You have to really put the water in these formations because you're fighting the vertical permeability, which is always many, many times lower than the permeability you see in the lateral direction in the reservoir.

If you can inject water in the wellbore and let it extend out laterally, you always have better efficiency than if you're injecting in a horizontal fracture and the water has got to go up this way to get to the oil. Your efficiency is always much, much less. And so you really have to put the water to it to get a good sweep efficiency.

Q. On pages 34 and 35, those exhibits just demonstrate -- I'm sorry. Just page 34, that demonstrates the actual height that you'll achieve injecting at 1500 pounds?

A. Yes. That's what our model predicts the height would be.

Q. What is the zero point there? What does that represent?

A. That's the center of the perforations. And so the first two dashed lines are the Penrose, and then the other dashed lines represent the various layers that we put into our model based on the stress profile that was provided back in on page 29.

We try to break the layers of rock into as much detail as possible so we can see how the fracture grows through each one of those layers.

Q. Okay. I'm sorry. Again the first dashed line represents the extent of the Penrose?

A. The top of the Penrose, right.

Q. The top and the bottom?

A. The top, yeah. And it goes over there to a value of about 20, halfway between 15 and 25. And then down below, at a value of minus 15 to minus 25, there's another dashed line. That's the bottom of the Penrose.

MR. GILL: The pay portion of the Penrose.

Q. Okay. So does this indicate that you will actually have a portion of the fracture out of the Penrose?

A. Yes. There will be 10 to 15 feet of growth above and below the Penrose.

Q. But well within the Queen boundary?

A. Oh, yes. The top of the Queen is several hundred feet from this interval.

Q. Okay. The in situ stress profile on page 29, what does that stress number actually represent? Is that the stress in any one direction, or is that the average, or what is that?

A. That's the minimum principal stress, is what's commonly referred to. That's the pressure that's required for a fracture to grow through that particular interval, fracture that cannot grow through that interval unless the pressure inside the fracture gets above that stress.

Q. In what direction? Does it matter?

A. Well, if you're looking at, you know, up or down, then it's in that direction.

Q. Okay.

A. It's that pressure extension, or the extension pressure that was on a previous diagram, that's the pressure that's driving the fracture. It's out at the crack tip, and it's driving the fracture either deeper into the Penrose or up into other anhydrite sections or down into other zones. It's that pressure at that crack tip that's driving that fracture.

When that pressure exceeds the stress that's shown on this log, then the fracture can grow through that particular layer and will.

Q. So this exhibit basically demonstrates that that stress pressure is 2500 pounds above the Penrose?

A. That's true.

Q. Is that a different type of rock above the Penrose?

A. It's -- yes. It's anhydrite and limestone layers. The Penrose, as I understand, is a sand. So generally those are denser, harder rocks and sands.

Q. These stresses were calculated directly from the Halliburton log?

A. Yes.

Q. Was that done by you or Halliburton?

A. Halliburton.

Q. You stated earlier that the range or gradient of vertical fractures was .7 to .9?

A. If I had to pick an after range that we see, it's within that range, yes.

Q. Is that for -- what type of rock is that for?

A. Really all types of lithology.

Q. All types?

A. We deal primarily with sands when we're talking about hydraulic fracturing because most people don't hydraulically fracture carbonate reservoirs. But those are still typical fracture gradients in carbonate reservoirs also.

Q. Injecting at the proposed 1500 pounds, what's your best guess on what would happen in the wells that do have the vertical fractures present?

A. Well, the fracture is going to grow up a little bit, as shown on the diagram on page 34. That's our prediction at the 1500 pounds of surface pressure. It's going to grow up 20 or 30 feet maybe and down another 10 or 15 feet into some of the other nonproductive intervals of the Queen. But it should be contained primarily to the Penrose interval.

Q. Looking at the step-rate tests on the No. 5 and 9 and 25, it's your opinion that we do not see a break on these tests or a fracture or an extension of a fracture?

A. Right.

Q. We do see something at least on these tests. What in your opinion is that?

A. Well, somebody took that data, the bottom hole data, and just drew some straight lines on it and picked an intersection point and called that the parting pressure. As I look at it -- and I re-plotted it because I think there's a few points that may not be plotted exactly right, but I re-plotted it.

Say, for example, No. 5 well, it's shown, two straight lines are drawn on the graph with an intersecting point at 1505 PSI. If I look at that data, which we've re-plotted based on -- over on age 15, I just see a continuous curve in the data without any real breaks to speak of. And the pressures are still increasing at a much faster rate than I would expect if the fracture was open. And that's the basis for my conclusion.

I've illustrated how these different curves compare over on page 20. The pressure curves for 5, 9, and 25 are still increasing at a fairly rapid rate when compared to No. 14 and No. 22. Those wells, the pressure curves have flattened out for all practical purposes.

And so I really didn't see what we looked for in the pressure curves that indicate to me that the fracture had opened, and that is this break-over point. It's still just slowly increasing. And it appears to me that all they're doing is just repressurizing the formation.

And at some point the fracture is going to open and the pressure is going to break over. I just don't see it in the data for those other three wells.

Now, it could be. Now, this is a very interpretive test. No doubt about it. That could be the opening pressure. But if it is, that means that vertical fractures do exist in these wells.

It's interesting that those three wells are deeper than the other two wells. I don't know if that means anything, but that would mean that at some point when you go from about 1600 feet down to around 18- to 1900 feet, that the fractures go from being horizontal to vertical. They change orientation within just a few hundred foot of surface depth.

I mean, it's possible. Anything is possible under the ground, but I just would find that very hard to believe.

Q. Mr. Robinson, is there any type of log or test available that you know of that might tell you after a period of time what might be happening down in the formation if you injected a high pressure? Can you tell later on if there's anything that you might not want to be happening?

A. Yes. Well, for example, if you possibly had some mechanical problems with the wells, there are these injectivity surveys which are a convenient way to look at channeling behind pipe and that sort of thing.

There's some new technology available, a technology that we've been a very big part of in terms of having the opportunity to work with companies that have developed the technology. And it involves the use of tilt meters and geophones to measure seismic activity and earth movement. And that describes whether you have vertical fractures and the heights of those fractures or horizontal fractures and the radius of those fractures.

It's technology that's been developed over the last five to ten years, and it's just now becoming commercially available. The reason it's taken so long and still not applied very widespread is because it's very expensive. Surveys in the \$30-, \$40-, \$50,000 range.

But the technology is there that can tell you through seismology and earth motion whether or not you have fractures propagating in a vertical direction or a horizontal direction and exactly what's going on underneath the ground.

EXAMINER CATANACH: I believe that's all I have, Mr. Kellahin.

MR. KELLAHIN: Just a follow-up question with Mr. Robinson.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Define the term leak-off.

A. Leak-off is just -- that's the waterflood. That's the fluid leaking from the fracture into the rock into the porous pay section that's flooding the oil hopefully over toward the producing wells.

Q. Without that you have no opportunity to recover the secondary oil?

A. That's right. I mean that's your waterflood. It's just fluid flow from the fracture into the porous permeable sand.

MR. KELLAHIN: Thank you. I have no further questions.

EXAMINER CATANACH: Anything further in this case?

MR. KELLAHIN: Only a point of inquiry,

Mr. Examiner. Mr. Gill has represented to you and the data demonstrates that the project must be abandoned at this point without a pressure limitation increase. It puts at risk the opportunity to recover more than half a million barrels of oil.

You asked during Mr. Robinson's presentation if he had made an engineering study of sweep efficiencies. I must tell you we haven't done that. I had presumed that that would be an operator's decision to determine at what volume he would introduce water into the waterflood so that he could maximize his recoveries.

And what we focused on was the issues of concern to you as a regulator to keep the fluids confined so that they're not putting at risk anyone else's hydrocarbons or putting freshwater in jeopardy. And so it will be my error if you desire some kind of reservoir sweep efficiency study because we simply have not done that. We have focused on the other aspects.

EXAMINER CATANACH: Mr. Kellahin, that was just for my information. I assure you that it won't be considered in my decision.

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER CATANACH: There being nothing further, Case 10495 will be taken under advisement.

[And the proceedings were concluded.]

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 10495, heard by me on June 25 1992.

David R. Catanach, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

I, Debbie Vestal, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I caused my notes to be transcribed under my personal supervision; and that the foregoing is a true and accurate record of the proceedings.

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

WITNESS MY HAND AND SEAL JULY 6, 1992.

Debbie Vestal

DEBBIE VESTAL, RPR
NEW MEXICO CSR NO. 3