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

27 April 1988

EXAMINER HEARING

IN THE MATTER OF:

Application of Anadarko Petroleum Corporation for the amendment of Division Order No. R7773, Eddy County, New Mexico. — CASE 9364

BEFORE: Michael E. Stogner, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division: Charles E. Roybal
Legal Counsel for the Division
Oil Conservation Division
State Land Office Building
Santa Fe, New Mexico 87501

For the Applicant: W. Thomas Kellahin
Attorney at Law
KELLAHIN, KELLAHIN & AUBREY
P. O. Box 2265
Santa Fe, New Mexico 87501

I N D E X

E X H I B I T S

EXHIBITS CONT'D

MR. STOGNER: Call next Case Number 9364, which is the application of Anadarko Petroleum Corporation for the amendment of Division Order No. R-7773, Eddy County, New Mexico.

Call for appearances.

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of Santa Fe New Mexico, appearing on behalf of the applicant, and I have one witness.

MR. STOGNER: Are there any other appearances in this matter?

Will the witness please stand and be sworn at this time?

(Witness sworn.)

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Stogner.

JOHN H. BEAIRD, III,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q For the record, Mr. Beaird, would you please state your name and occupation?

A I'm John H. Beaird. I'm a Senior Reservoir Engineer with Anadarko Petroleum Corporation in Houston, Texas.

Q Mr. Beaird, as an engineer have you made a study of the performance of certain injection wells in the Ballard Grayburg-San Andres Waterflood Project in the Loco Hills Field of Eddy County, New Mexico, that's operated by Anadarko?

A Yes, sir, I have.

Q And have you previously testified before this Division as an engineer?

A Yes, sir, I have.

Q And pursuant to your study have you prepared a book that contains all your exhibits, conclusions, and methods of analysis for this application?

A Yes, sir, I have.

MR. KELLAHIN: At this time, Mr. Stogner, we tender Mr. Beaird as an expert petroleum engineer.

MR. STOGNER: Mr. Beaird is so qualified.

Q Mr. Beaird, I have pulled out of the package of exhibits a display that is captioned Base Map. It is identified in the exhibit book as Exhibit Number One. If you'll remove that and put that in front of you, using Exhibit Number One, Mr. Beaird, would you identify for the Examiner what is indicated with the yellow outlined area?

A Exhibit One is a base map of the Ballard Grayburg-San Andres Unit.

The yellow line is the unit outline.

Q When was the unit originally approved?

A It was originally formed in 1973. The initial project consisted of the injection wells which are labeled in red.

Q You'll have to speak up just a little bit, John.

A I'm sorry.

Q The horizontal limits of the unit have not changed over the years, have they?

A No, sir, they have not.

Q And what is the unitized vertical interval for the project?

A The unit is -- it's unitized from 20 feet below the base of the Loco Hills, to 450 feet below the top of the San Andres formation.

Q You have a unitized interval of approximately how many vertical feet?

A Roughly 700 feet.

Q The original project area was the development of a waterflood in the San Andres on 160-acre 5-spot well pattern?

A It was on 160 acres for the Grayburg.

Q Okay, and how were those original injection wells identified?

A They are labeled with red dots on this map.

Q Those are wells that historically have been allowed to inject water at rates that exceed the current guidelines that the Division used for injection rates.

A They have no pressure limitation.

Q When we look to the expansion area in 1985, is it --

A '82.

Q -- I'm sorry, the '82 expansion area, how are those injection wells for the '82 expansion identified?

A Wells are labeled with a blue dot on this map. The order in which they -- they operate under has a 1550 psi surface injection pressure limitation.

Q And that was the result of an Order R-7000?

A I'll have to check that but I believe

that's right. Yes, sir.

Q That was approved by Mr. Stamets when he was reviewing this project for increase in -- I"m sorry, for the approval of the 10 additional injection wells for the '82 expansion.

A Yes, sir.

Q And you are going from 160-acre patterns down to 80-acre patterns in '82?

A Yes, sir.

Q And those 10 injection wells had a surface pressure limitation of 1550?

A Yes, sir.

Q And that was a rate that exceeded the .2 psi per foot of depth limitation?

A It was a pressure that did.

Q Okay. We went to the third and the last expansion in 1985, is that correct?

A Oh, yes, sir.

Q And what wells were included in the '85 expansion?

A They're shown with the yellow dots. The purpose of that project was mainly just to complete the reduction in spacing from 160 acres down to 80-acre 5-spots.

Q In the hearing and approval process that approved those last ten wells in 1985, that was done pursuant to Order Number R-7773?

A Yes, sir, it was.

Q And all those orders are contained in the exhibit book in the appendix in the back?

A Yes, sir, they are.

Q As a result of that last expansion was there a surface limitation pressure on those wells?

A There was a surface limitation of .2 psi per foot of injection depth but the order also contained the provision that the Division director could increase that pressure limitation upon satisfactory showing that the injected water was being kept in the confining strata, which in this case is the Grayburg-San Andres formation.

Q With that order being in place was Anadarko able to inject any volumes of water in the 20 expansion injection wells under that limitation?

A No, sir, we're not.

Q What is the problem, John?

A The permeability of the Grayburg sands is so low that you really need to be a little bit above the parting pressure of the rock to get an economical quantity of water in the ground in order to produce your waterflood.

Q Have you made a study to determine whether or not the pressure limitation above the parting pressure for the formation can be exceeded?

A Yes, sir, I have.

Q And what have you found?

A Our determination is that you can exceed the parting pressure as determined by step rate tests by up to 450 psi and the fracture that you generate will not propagate outside of the pool boundaries or outside of the vertical limits of the unitized interval.

Q Let's turn to the exhibit book and if you'll go behind the tab that is captioned "Discussion", that discussion represents your work product, does it, John?

A Yes, sir, it does.

Q And there's 18 pages of written discussion about your analysis and conclusions?

A Yes, sir, there is.

Q If you'll turn to page 17 of that analysis, are these the ten wells that are involved in the 1985 expansion?

A Yes, sir, they are.

Q And they're identified by a number?

A Yes, sir, they are.

Q In the first tabulation to the right of the number it says "pressure limitation"?

A Yes, sir.

Q For example, on the first well, the 10-9 Well, the 895 pounds, is that a surface pressure?

A Yes, sir, it is.

Q And does that represent the results of step rate tests for that well?

A Yes, sir, they do.

Q Okay. And is that correct for all the rest of the wells on that tabulation, that the first column represents the pressure limitation realized after a determination of the pressure from step rate analysis?

A Yes, sir, it is.

Q Okay, what is represented in the last column?

A The last column is the additional or the pressure limit that we're requesting the current order to be modified to. We've added, essentially added 450 psi to all the current pressure limits.

Q Have you put in Mr. Stogner's exhibit book copies of all the information from which the step rate tests in the first column were derived and determined?

A Yes, sir, I have.

Q Based upon your study, John, what have you found with regards to this project, first of all concerning what your decline curve analysis shows you is the anticipated additional ultimate recovery if the ten injection wells are successful?

A We ought to realize an additional 250,000 barrels of secondary oil from these ten injection wells, if we can get some water in the ground.

Q What have you found with regards to the ability of you as operator to exceed the step rate pressure limitations?

A Would you ask me that again?

Q Yes, sir. You have used temperature log analysis and other methods of analyzing your study to determine whether or not you can exceed the pressure limitation --

A Yes, sir.

Q -- that's established on each of those wells, and have you determined and concluded to your own satisfaction that you can inject above that limitation and still keep the fluids confined within the unitized formation.

A Yes, sir, I have.

Q Okay. And in each one of those instances is the proposed injection rate greater than or less than the 1550 pounds approved by Mr. Stamets in the 1982 expansion?

A They're all less than that pressure.

Q In trying to make the '85 order work, were you able to inject water under those limitations?

A No, not a reasonable quantity.

Q All right. Let me have you explain to us what your conclusions of your study are. What conclusions have you reached?

A Primarily, one is that there's a reserve loss of 250,000 barrels by the fact that we can't water into the ground in these ten injection wells.

Our second conclusion is that the wells operated under the two previous orders, one which had no pressure limit, the other which had 1550, the waters being injected into those wells is all being contained within the Grayburg or the Upper San Andres, all within the pool boundary and within the vertical limits of the unitized interval. The fractures that are being generated are no threat to the fresh water zone.

And that about sums it up.

Q When the Commission went through the process of approving the 1982 and the 1985 expansions of the project area, was an inventory made of all the wellbores within the project area and those within a half mile of any injector well?

A Yes, sir, they were.

Q And did the results of any of those surveys determine and identify any wellbore that was improperly cemented, plugged, or completed in such a fashion that would serve as a conduit to allow disposal fluids to migrate out of the unitized formation?

A If any well was discovered in that condition it has been repaired.

Q Let me have you go through your analysis of the supporting basis for your conclusion that we can safely exceed the step rate injection limitation by as much as 450 pounds for each of these wells. Okay?

You concluded that the fracture length, both horizontal and vertical, will remain confined within this 700-foot vertical interval?

A Yes, sir.

Q What caused you to reach that conclusion?

A We evaluated the temperature log which you have back there, temperature profile, if I can be permitted to walk out there.

Q Sure, if you'll go to the display on the board and identify, first of all, I think this is Exhibit --

A Exhibit Fifteen.

Q Exhibit Number Fifteen.

A This is a cross section of the injectivity profile, north/south through the unit. The cross section is hung --

MR. STOGNER: Why don't you stand on this side, talk in that direction, and talk loud enough so the reporter can hear you.

MR. KELLAHIN; Speak up, John,

don't get soft.

A The logs are hung stratigraphically in the Grayburg formation. We have the top of fluid migration marked; the unit boundary; the top of the San Andres; and the bottom of fluid migration.

Each one of these logs has three indicators of fluid flow.

In the left tract of each log highlighted in red is the velocity profile, which is one measurement of fluid flow.

In the tract next to that highlighted in yellow is a tracer profile, in which radioactive elements are injected and they're followed as they leave the perforations, and then the volume of fluid, where it's gone is measured in this column.

Then in tract two, the righthand side of the log, we have a temperature profile, and the (unclear) runs that were run one hour, two hours, after a well -- the injection had stopped.

The temperature profiles will tend to go back to the gradient that they were originally at.

MR. STOGNER: The what?

A Temperature profiles would go back to the typical gradient that they had.

MR. STOGNER: Gradient, okay.

A Yes, sir. In this log, which is the

second one from the left, you have the initial temperature curve. Then the well is shut in and this recedes back and this is an indication of how much fluid went to those perforations and where it went. When this gradient comes back to where it was before, that's an indication that there was no fluid movement above that point. The logs are very sensitive to any type of fluid flow, as you can see down here on this log where they all track on top of one another.

MR. STOGNER: Now, which log are you pointing at?

A I'm talking -- I'm pointing at the Anadarko Ballard Grayburg-San Andres Unit No. 16-1. It's on the far righthand side of the log. They all stack one on top of the other, which indicates that no fluid flow has occurred below that point, but you'll see that there's a deviation right in here, in this area, which is about --

MR. STOGNER: And what area --

A -- 2700 feet. It appears to me that that's probably just a casing collar leak.

This -- the temperature logs have been used for quite a number of years to indicate fluid movement. There are several papers that have published on it. I think I have seven or eight references in there. They were all researched and the methods that were described were used to pick these tops.

If you'll notice that the third log from the right, that on the bottom the fluid migration that these curves are not stacked like they are in the other wells. This is because when the well was logged they had shift in the temperature from one to the other. In this case 72 degrees is right here and it's 6 to 7 units over in the other log, so they're really not the same.

I just -- I picked that gap and just put that point.

MR. STOGNER: And you're referring to the --

A I'm referring to the Ballard Grayburg-San Andres Unit No. 5-4.

So what we've done is we knew that what was going on in the other wells wasn't causing any problems to the field. We'd seen good waterflood response in this area. We knew that the fluids were being contained and these injection pressures were higher than what the step rate tests were showing us on the later development.

What we didn't know was -- was how high we could exceed this parting pressure and keep that fracture confined; what kind of pressure did this relate to, because these -- these were all run in 1981 to 1983. We had no way of going back and finding out what closure stress they had at that time.

So we went through a mechanical properties log, which is a full wave sonic. I'll give you a brief analysis of what we did, both methods and then go into detail on the (unclear).

A full wave sonic log is a step beyond the regular acoustic log that measures porosity; not only do you get the compressional wave which measures your porosity but you get a sure wave arrival.

You can use those arrival times to get Poisson's ratio --

MR. STOGNER: Do you want to spell that?

A P-O-I-S-S-O-N-'-S R-A-T-I-O. and rock moduli.

With this log you can calculate the stress vertically through the wellbore.

We also attempted to predict what the pressure was at these heights using fracture modeling, computer modeling.

And that's the basis of what we did. Our 4-way sonic work, we were hoping to see that some of these denser dolomites up in the top of the -- between the Loco Hills and the Upper Metex sand, which is about 2500 feet, were -- were stopping the fracture growth. We didn't see that.

What we saw was that this formation is pretty competent all throughout. It's consistent. There's no zones up here that are going to keep your fracture from going either way, but there's also no zones in there that are going to make it go off random. I mean it's just not inherently weaker up here than it is down here. It's real consistent through the wells.

So what we did was we tied this log or this cross section here, which showed us what the heights were, with the pressures that we got on our compute modeling to predict our 450 psi Delta P above the stress, closure stress.

We can go through that in detail now, if you want to, or we can --

MR. STOGNER: Now, this map that we have on the wall, is that Exhibit Two or what is it?

A Exhibit Fifteen

MR. STOGNER: Fifteen.

Q Let's have you return to your seat, John, and let's look at the discussion and identify for Mr. Stogner in the discussion narrative the pages at which you describe in detail your analysis of the fracture generally and then your method of analyzing to determine the length both vertical and horizontal of these fractures.

A It begins on page five.

Q And that begins a general outline discussion of fractures in general?

A Yes, it does.

Q Where did you specifically discuss your analysis of the fracture height and the stress required in order to generate or propagate the fractures?

A We began that on page 7, the stress variations.

Q Okay. And you've shown your engineering calculations on that page?

A Yes, sir.

Q In the study you've made, John, have you reached an opinion or a conclusion as to the anticipated shape that the fractures will take as they leave the wellbore?

A Yes, sir, I have.

Q And what is that opinion?

A My opinion is that the maximum vertical height we're going to have will be at the wellbore and that the vertical height will decrease as the fracture propagates laterally.

Q What causes you to reach that opinion?

A The papers that I've researched, that's the only conclusion that's been drawn. They either are completely rectangular or they decrease vertically in height with length to become elliptical.

Q Is it reasonable to conclude that there will be a shape propagated that will cause the fractures to extend beyond the unitized formation?

A No.

Q Not at these pressures?

A Not at these pressures, no, sir. I'd like to point out that even though the methodology we use is a little different, and we're asking for an initial pressure above the step rate tests, the first group is well within what's been shown on this log to be contained and be safe.

Q Does a step rate test continue to serve as a useful tool for the Division to set and determine pressure limitations?

A It is a starting point. It will indicate where the rock is going to part but it doesn't tell you how high that fracture is going to go, at what pressure you can inject at above that and still maintain your fracture within the confining strata.

Q For this particular waterflood project it is too conservative a benchmark by which to pick the surface injection pressure limitation?

A Yes, sir, it is.

Q If we exceed the parting pressure in the formation, do you have an opinion as to whether or not it will adversely affect the sweep efficiency of your injection wells?

A Yes, I do.

Q And what is that opinion?

A I don't think it will.

Q Why?

A If we don't put any water in the ground we have no sweep efficiency, so there's nothing to be reduced.

Q If we exceed the parting pressure of the formation and keep these fractures open, will that give you a sweep efficiency that leaves a substantial portion of the oil beyond the sweep efficiency of the flood?

Are you leaving oil that -- in place that you would otherwise recover?

A No. By being able to inject in these wells we're going to recover an additional 250,000 barrels that we're not going to recover under current conditions.

Q You're just not going to get it any other way.

A No. Exactly right.

Q Now, apart from your computer modeling analysis for your presentation, can the temperature survey logs be utilized as a convenient way to monitor and to use that then to calculate using your engineering calculations the lengths and extents of the fractures?

A Yes, sir, they can.

Q We're not giving them witchcraft, or voodoo, or something that they can't use as administrators to reliably determine what these fracture limitations ought to be.

A No, sir, we're not. I mean there -- we tried to pursue the modeling of hydraulic fractures in this field in every available way that we had we tried to tie it with something that was practical, that took a lot of the guesswork out, and that was the temperature logs that we already had in the field. They can be run after the order has been approved to determine exactly what the height is, how the model fits with actual results.

Q Why don't you take us through some of the unit performance curves that you have prepared on the wells so we can see what has happened with different stages of pressure limitations on your injection wells?

Which is the first one you'd like to look at?

A Look at Exhibit Number Three first.

Q Okay. Let's take a moment and make sure we've got that one.

All right, John, would you take a moment and identify for us Exhibit Number Three?

A Yes, sir. Exhibit Number Three is a unit performance curve.

Q When you talk about a unit performance curve you're talking about performance for all the wells in the unit?

A Yes, sir, I am. It contains a curve showing oil production, which is highlighted in green, the scale being in barrels per day on your left; GOR; water production; and also water injection.

Q Having plotted that information on the curve what does it show it?

A From the curve we have a well count at the bottom. There are 49 producing wells currently in the field. The unit's making 387 barrels a day, 3173 barrels of water per day, at an 89 percent water cut. Also contains 43 injection wells which are injecting 6400 barrels of water a day at an average of 1228 psi.

Injection withdrawal ratio was 1.8-to-1.

Just trying to show with this exhibit that the Ballard Unit has been a good waterflood. You can see back in 1973 when it was unitized initial production was roughly 70 barrels a day. After injection began in the last half of 1974 oil response was seen 6 months later to that with the peak rate early in 1981 at roughly 900 barrels a day.

Current is on -- the unit is currently declining at roughly 13 percent a year.

Q Your next exhibit is Exhibit Number Four?

A Exhibit Number Four is the same performance curve.

Q All right, just before you look at that one, let's get it out.

A Okay.

MR. STOGNER: Which exhibit?

MR. KELLAHIN: Number Four.

MR. STOGNER: Number Four. Okay.

Q All right, sir, identify for us what you've done.

A Exhibit Number Four is the same performance curve, only in this case we've highlighted oil production associated with each one of the infill projects that we did, the 1982 expansion specifically, on this curve.

The 1982 expansion, like was stated before, was 160 acres to 80-acre 5-spot pattern reduction for the field.

We added 10 injection wells and 8 producing wells.

486,000 barrels of incremental oil was associated with the 1982 infill project. Of that 250,000 barrels, roughly, is associated with the producing wells drilled, and then another 237,000 barrels were associated with the conversions to injection.

That's shown in the 1982 waterflood project, which is highlighted in yellow on the right side of your curve.

Q Which color identifies for us the incremental volume of additional oil with the last expansion in '85?

A That will be on the next curve.

Q All right, let's turn to that one.

MR. STOGNER: Curve 5?

A Yes, sir, Exhibit Five.

MR. STOGNER: Exhibit Five.

A This curve shows our projected response that we were expecting from conversion of the 1985 project. You can see it's the little box on the upper righthand side, proposed waterflood project, predicted secondary EUR, incremental reserves.

You can see below that, that that was the based line before the work was going to be done and our actual performance is following right on that base line. This is where we get our 250,000 incremental barrels being lost due to the current operations.

Q Had injection in the 10 additional injector wells from the '85 expansion been successful, you had anticipated the oil production line to have fallen on the top of the two lines.

A Yes, sir, it would have fallen along --

Q The top portion of the yellow line.

A It would have fallen along the proposed waterflood project line, yes, sir.

Q And it has not.

A It has not, no. That indicates a loss of reserves, based on that produced.

Q Would you go through the exhibit book and not discuss in detail the exhibits but just simply go through and identify and highlight for the Examiner what is the other information you've contained in the exhibit book?

A That would start with Exhibit Six.

Q All right, sir, Let's do that.

A It's a full wave sonic log on our Ballard No. 23-4; essentially a mechanical properties log.

The first part of this log shows the sonic wave train arrivals. It's the first log that's used to compute the fracture height.

There's basically three steps taken from the full wave sonic to get to a fracture height volume. That's Exhibit Seven, Eight, and Nine.

The first one is a rock properties log. It just tells you basically your Poisson's ratio and other rock properties, rock moduli.

Exhibit Number Eight is a bore hole stress log. After you obtain the rock properties calculations are made using the equations in the top part of the log under definitions.

These are then plotted vertically through the wellbore.

And then finally Exhibit Nine the pressure frac height log. It contains the calculations of fracture closure stress using the rock properties calculated on the other three logs.

You can open that up. The fracture closure pressure is shown in frac 2 on the lefthand side of the log as the solid blue line. Pressures range from about 1200 to over 1500 psi through the interval.

You notice just by looking at the log that there's a definite character difference between roughly 2480 and 2700 in the interval above that.

After we ran this log that character difference made it suspect to us that maybe there was error in the data that we had obtained. Apparently the perforations that existed, the injection history of this well acidizing, whatever, had caused changes in the -- around the wellbore that didn't give you true readings as far as what the stress was. We therefor couldn't go ahead and use this to calculate what the -- or didn't think it would be correct to use this calculate what the fracture height would have been.

If you do look up from 2480 on up the wellbore, the curve is relatively smooth. There's no indication of any zone that's not competent; that's going to fracture at a lower gradient than the ones below it and take all the fluid.

Exhibit Ten begins the fracture modeling work. There's basically two groups of thought now on fracture modeling, and they differ in how they calculate width.

One group assumes that width is proportional to height. This is mainly Perkins & Kern.

The other group assumes that width is proportional to length. This group would include Danashy (sic), Deklerk.

But all of these models have to assume that height is some number and that it's going to be constant through this calculation.

So what we did in our analysis is we went ahead and we assumed several different fracture heights, 100 feet, 150, 200 feet, 250, but we knew from the temperature logs basically what they were going to be.

So we went ahead and took an injection

rate of 250 barrels a day with the assumed heights that I told you, and then we calculated what those pressures, the resulting pressures, were going to be.

Exhibit Ten is a plot of that analysis. It's highlighted for the 100-foot fracture.

The green diamond shows the constant 100-foot fracture height.

The red triangle represents the velocity of the fracture (unclear) so when equilibrium is obtained, that velocity is zero.

The orange square is the incremental pressure that you are above the closure pressure.

So what I did in this case, I extrapolated the fracture velocity to zero and I went up to a point where that intersected the extrapolation of the pressure, read that over and that's 347 psi, or 3.47 psi per foot over the 100-foot assumed height.

I went ahead and I repeated that on Exhibits Eleven, Twelve, and Thirteen, for the 150, 200, and 250-foot assumed fracture height.

That resulted in pressure above closure pressure of 2.63 psi per foot for the 150 foot case; 2.13 psi per foot for the 200 foot case; and 1.8 psi per foot in the 250 foot case.

I then combined all of that data onto

Exhibit Fourteen, which is a plot of that Delta pressure psi per foot versus the assumed fracture height.

You can see from the curve that it's a real smooth fit between those points and they can easily be extrapolated to higher fracture heights that you didn't actually calculate.

Since we knew what this Delta pressure was going to be versus the fracture height, it was just now a determination of what the height was. That's where we incorporated the temperature log.

If you'll turn to Exhibit Number Sixteen, we've added the height ranges, which is from 295 to 375 feet for the wells on that cross section which are similar to the well that we're modeling, extrapolated those up into the curve and came over with a Delta P of 21.55 and 1.27 psi per foot, which results in 457 and 478 psi above closure pressure.

That concludes what we did on our computer modeling.

Q You've provided in the written discussion a step-by-step narrative of what you've just discussed for us.

A Yes, sir, I have.

Q If the Examiner desires to do so, he can read the narrative and see how you've made the calculation and determined the methodology you've used for this project.

A Yes, sir, he can. I've also included references that I used in doing the work and they're also included.

Q Mr. Beaird, how long have you been involved on behalf of your company in analyzing the performance in this particular waterflood project?

A On and off for several years.

Q Does the work represented in this exhibit book, being Exhibits One through I believe Thirteen is your last exhibit? I'm sorry, Sixteen --

A Sixteen.

Q -- Sixteen, represent your work product and analysis for this application?

A For this application, yes, sir, it does.

MR. KELLAHIN: At this time, Mr. Examiner, we'd move the introduction of the exhibit book, which includes Exhibits One through Sixteen.

In addition I have the certificate of mailing of notice of this hearing to affected parties, which we've marked as Seventeen, and we would request that it also be admitted at this time.

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

MR. KELLAHIN: That concludes my direct Examination of Mr. Beaird. We submit him for cross examination.

CROSS EXAMINATION

BY MR. STOGNER:

Q This is indeed a bunch of information to digest in such a short period of time and all the work that -- how much time are you talking about that you put into this?

A We spent several months on this, since the fall of last year.

And like you can see from the full wave sonic work we did, a lot of it wasn't productive. I mean when you have a problem you pursue it through any direction you can until you find a solution and that's what we've done.

We thought we'd go ahead and bring you everything we did.

Q I was looking at your references here. Now which, which of the references did you use most?

A Did I use most?

Q Yeah.

A I've read all of them.

Q Well, which one of them --

A Well, let me get back to them. There are several papers that are presented that directly dealt with injecting at above fracture gradients in waterfloods, the first one by Felsenthal & Ferrell is a pretty good paper.

Q Felsenthal and --

A They were with Continental Oil at the time they did the work.

Q So reference number one.

A Yes, sir.

Q Okay. Now I notice that you used a case study here. Which one is that one now, or I believe there was a case study, wasn't there, in the Cotton Valley, reference number fourteen.

A Oh, yes, that was --

Q Was this essentially the same kind of study that was done, that you're trying to do?

A They were using the full wave sonic log to do what we tried to do. They had better results because they had a sand/shale sequence, so they had shales in there that had exhibited higher closure stress.

Our rock tends to be very homogeneous vertically, even though there's porosity stringers in the sand, there's nothing going on that Poisson's ratio enough to give you a barrier as far as fracture generation.

Their main conclusion was that you can

use a full wave sonic log to determine these closure stresses.

I can send you copies of any of these you want.

Q I believe I can reference most of them.

A Okay.

Q But if I feel that I need one, I'll -- we'll get hold of you.

A All right.

Q I'm looking in particular at Exhibit Number Nine.

A Okay.

Q That would be the frac pressure - fracture height log. So that I'm sure that I'm reading that right.

A Uh-huh.

Q Let's look at the bottom portion of the log.

A Okay.

Q Why don't you explain about what the colored areas are opposite the perforations?

A On which side?

Q Am I actually seeing a fracture?

A What they're trying to show here on this log is the fracture height associated with an incremental pressure above the closure strip.

The problem with this log is it doesn't deal at all with the fluid leak off. It's a mechanical log. It's a static evaluation of stresses. The main pressure drop you have in an injection well is a leak off; that's what you're trying to do, is inject fluid in the reservoir.

What we were thinking was that if we could find a zone that had a couple of hundred pounds closure stress higher than what we were injecting into, that we would propose that type of limitation. That's what was going on in the area. That's not what we found out but, yes, that's supposed to indicate the Delta P between the closure and associated fracture height.

MR. STOGNER: Does anybody else have any questions of this witness?

So we all understand it.

Mr. Kellahin, would you submit me a rough draft order for this?

MR. STOGNER: Be happy to.

MR. STOGNER: And if I still have any questions, I'm going to reserve the right to do it with letter or with correspondence in this particular matter.

There's a lot of information to digest and it's going to take awhile and if I do have any questions, I will make sure that Mr. Kellahin will get a copy of that.

MR. KELLAHIN: Thank you.

MR. STOGNER: So the case file will also show any -- any correspondence from me.

Or better yet, are you going to write a paper?

A No, sir.

MR. STOGNER: If there are no other questions Mr. Beaird may be excused.

If there is nothing further in this case, it will be taken under advisement.

(Hearing concluded.)

CERTIFICATE

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. 9364, heard by me on 27 April 1988.

_________________, Examiner
Oil Conservation Division