STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:	)	
APPLICATION OF POGO PRODUCING COMPANY TO INSTITUTE A COOPERATIVE TERTIARY RECOVERY PROJECT AND TO QUALIFY THE PROJECT FOR RECOVERED OIL TAX RATE, LEA COUNTY, NEW MEXICO	)	CASE NO. 13,581

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: WILLIAM V. JONES, JR., Hearing Examiner

October 20th, 2005

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, WILLIAM V. JONES, JR., Hearing Examiner, on Thursday, October 20th, 2005, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

October 20th, 2005
Examiner Hearing
CASE NO. 13,581

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A P P E A R A N C E S

FOR THE DIVISION:

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Santa Fe, New Mexico 87505

FOR THE APPLICANT:

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* * *

WHEREUPON, the following proceedings were had at 9:10 a.m.:

EXAMINER JONES: At this time let's call Case 13,581, Application of Pogo Producing Company to institute a cooperative tertiary recovery project and to qualify the project for recovered oil tax rate, Lea County, New Mexico.

Call for appearances.

MR. BRUCE: Mr. Examiner, Jim Bruce of Santa Fe, representing the Applicant. I have three witnesses.

EXAMINER JONES: Any other appearances in this case?

Will the witnesses please stand to be sworn?

(Thereupon, the witnesses were sworn.)

LESLYN M. WALLACE,

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

DIRECT EXAMINATION

BY MR. BRUCE:

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

A. Leslyn Wallace, Midland, Texas.

Q. Who do you work for and in what capacity?

A. I'm a district landman for Pogo Producing Company.

Q. Have you previously testified before the

Division?

A. Yes, sir, I have.

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

A. Yes, sir, they were.

Q. And are you familiar with the land matters involved in this Application?

A. Yes, I am.

MR. BRUCE: Mr. Examiner, I'd tender Ms. Wallace as an expert petroleum landman.

EXAMINER JONES: Ms. Wallace is qualified as an expert petroleum land manager.

Q. (By Mr. Bruce) Would you first please identify Exhibit 1 and describe the land involved in this Application.

A. Exhibit 1 is an illustration or a plat of the acreage which we are seeking approval for the tertiary recovery project. The acreage is outlined with a hached line, and it is the 13th enlargement of the Delaware sand participating area within the Cotton Draw Unit.

The south half of Section 16, which has the hach marks on it, is also acreage that we seek the Application to be approved, but it is not a part of the participating area, nor is it a committed tract to the Cotton Draw Unit.

Q. And besides seeking the tertiary recovery

project, Pogo also seeks to qualify the project for the recovered oil tax rate, does it not?

A. Yes, it does, sir. And the acreage is owned 100 percent by Pogo Producing Company.

Q. And so this would be a -- rather than a statutory unitization, this would be a cooperative carbon dioxide flood, would it not?

A. Yes, sir, it would.

Q. On this exhibit, within the participating area, there are some circled numbers. What are those numbers?

A. Those represent the tracts within the participating area, and those tracts -- the participation factors for those tracts are determined based on surface acres.

Q. Okay. We also have Exhibit 1A as a land plat. Is this simply showing some leasehold ownership in the area?

A. Yes, it is, it's a copy of a Midland Map Company map, and it shows the leasehold ownership within a half mile and two miles outside the boundary of the participating area in the Monsanto State Lease in the south half of Section 16.

Q. Okay. Let's move on to the unit, just very briefly. What is Exhibit 2?

A. Exhibit 2 is a copy of the unit agreement for the

Cotton Draw unit that was dated April 21st, 1958, and originally when the unit was approved, it covered some 35,000 acres.

Q. It has since been contracted to what, something like 10,000 or 12,000 acres?

A. That is correct, I think it's about 12,000 acres.

Q. But this unit agreement is still in effect?

A. Yes, sir, it is.

Q. And under this unit agreement -- This was an exploratory unit?

A. It was a federal exploratory unit, yes, sir.

Q. Okay. And in exploratory units participating areas are formed and production is shared on an acreage basis; is that correct?

A. That is correct, and that's shown under Section 11, page 13, in the unit agreement itself.

Q. Okay, and that's -- Section 11 is the participation after discovery, and that pertains -- Sections 11 and 12 pertain to the formation of participating areas, do they not?

A. That's correct.

Q. What is Exhibit 3?

A. Exhibit 3 is a copy of the unit operating agreement for the Cotton Draw unit that is still in place, but when it was originally executed there were about a

dozen parties that participated and joined in the unit operating agreement at the time.

Q. And as you said, now not only within the Delaware participating area but in the south half of Section 16, Pogo is the sole working interest owner in the injection interval; is that correct?

A. That is correct.

Q. What is Exhibit 4?

A. Exhibit 4 is a copy of the application for the 13th and the final enlargement of the Delaware sand participating area within the Cotton Draw Unit. And if you'll note on the back page of this application, there is 160 acres --

Q. Excuse me, the -- Mr. Examiner, the final page of that exhibit.

A. Yeah, the final page of Exhibit 4.

Q. Which is a land plat.

A. The land plat, yes.

It shows approximately 160 acres. It's the south half of Section 16, to be within the participating area.

But Exhibit B of the application lists that lease as well, but it does state that that lease was never committed to the Cotton Draw Unit. Therefore, the production that's coming from that lease is shared on a lease basis only, and it is not apportioned or shared by

the participating area.

Q. Okay. So even though the PA, the participating area, allegedly covered part of the south-half, Section 16 lease, none of the production from the south half of Section 16 is allocated to the rest of this acreage?

A. That is correct.

Q. And by the same token, none of the production from the participating area is allocated to the south half of Section 16?

A. That is correct.

Q. And this last expansion was done in 1962?

A. Yes, effective April 1st, 1962.

Q. And the engineer is going to discuss this later in more detail, but at this point production is marginal on these leases, isn't it?

A. Yes, sir, it is.

Q. Certainly a stripper status?

A. Stripper status, yes, sir.

Q. What is Exhibit 5?

A. Exhibit 5 is the order approving the Cotton Draw Unit. It was Order R-1186, and it was approved June 4th, 1958. And again, the Cotton Draw Unit originally covered a little over 35,000 acres.

Q. Subsequent to the formation of the unit and subsequent to the last enlargement of the participating

area, were waterflood projects approved for the Delaware in this pool?

A. Yes, sir, they were.

Q. And is that reflected in Exhibit 6?

A. Yes, Exhibit Number 6, there are actually two orders. Order R-3313 is the approval for waterflood of the Delaware sand under that Monsanto State Lease, which is the south half of Section 16. And then Order R-3314 is the approval of a waterflood for the Delaware sand under the Cotton Drawn unit participating area, the 13th enlargement, as is shown on Exhibit 1.

Q. And the waterflooding continues in these project areas to this date, does it not?

A. Yes, sir, it does.

Q. Okay. What does Exhibit 7 reflect?

A. Exhibit 7 is our illustration showing who the different offset owners are within a half mile of the boundaries of the participating area and the Monsanto State Lease.

And the colors obviously show on the legend who the offset owners are that were required to receive notice of this Application.

And there is an error on this map. If you look at Section 17, the northeast quarter should have been colored, but it is owned by Chevron, and Chevron did

receive notice of the Application.

Q. And written notice was given of this hearing to all of the offset operators, was it not?

A. Yes, sir, it was.

Q. And is that reflected in Exhibit 8?

A. Yes, Exhibit 8 is the copy of the notice that was provided to all the offset owners.

Q. And all of the offset owners have valid addresses had valid addresses, and notice was received?

A. Yes, sir, that's correct.

MR. BRUCE: Finally, Mr. Examiner, Exhibit 9 is a notice that was allegedly published in the Hobbs newspaper; I never received the affidavit of notice. I published this just in case. For a couple of days we didn't have an address for Eugene H. Perry, although we did find an address later on.

And I would request permission, whenever I receive the affidavit of publication, to make that part of the record.

EXAMINER JONES: Okay.

Q. (By Mr. Bruce) Now just a couple of final questions, Ms. Wallace.

Because there's already a unit agreement in place and an operating agreement in place, you do not propose altering the participation which has been in place now for,

what, 40-some years under the PA?

A. That is correct, sir.

Q. And with respect -- and -- Another question. The PA is -- Who are the lessors under the participating area?

A. Sorry, I should have covered that. The lessors are the federal government and the State of New Mexico and --

Q. There are no fee leases?

A. There are no fee leases, no.

Q. Okay. And with respect to this Application, the federal government and the state government were noticed also?

A. Yes, they were.

Q. And representatives of Pogo have spoken with both the state and federal government representatives, and they have not objected to this Application?

A. That is correct.

Q. Finally, with respect to that Monsanto State Lease, did Pogo approach the State Land Office about how to handle that, whether to expand the unit or to leave it as is, and did they not --

A. Yes, we did, and they advised us it would be best to leave it as it was.

MR. BRUCE: And that way, Mr. Examiner, production would just be allocated on a lease --

THE WITNESS: -- on a lease basis.

MR. BRUCE: -- on a lease basis.

EXAMINER JONES: Okay. For that lease?

THE WITNESS: For that lease.

MR. BRUCE: For that lease.

Q. (By Mr. Bruce) Were Exhibits 1 through 9 prepared by you or under your supervision?

A. Yes, they were.

Q. And in your opinion, is the granting of this Application in the interests of conservation and the prevention of waste?

A. Yes, sir, it is.

MR. BRUCE: Mr. Examiner, I'd move the admission of Pogo's Exhibits 1 through 9.

EXAMINER JONES: Pogo Exhibits 1 through 9 will be admitted to evidence.

EXAMINATION

BY EXAMINER JONES:

Q. So you're going to leave that lease out, but is there going to be injection wells on that lease?

A. Yes, sir, there will be injection wells. But the production from that lease will just be contained -- or the revenues from production on that will just be shared by the owners of that -- the royalty and the override under that lease.

Q. Okay. What about the royalty burden? Is it consistent throughout this area, one-eighth royalty?

A. The royalty is one-eighth on all the leases, yes, sir.

Q. State and federal leases?

A. State and fed.

Q. Are some of the leases better than others -- I mean, some of the tracts better than others? I guess that's immaterial at this point, because you're not proposing --

MR. BRUCE: I think you could ask the geologist there --

EXAMINER JONES: Geologist.

MR. BRUCE: -- and they could tell you --

EXAMINER JONES: Okay.

Q. (By Examiner Jones) This was a long time ago, the latest PA change on this.

A. Right.

EXAMINER JONES: I know I worked for Texaco, but I don't recognize this. 1962, I think. Long time ago.

(Laughter)

THE WITNESS: Way before your time.

(Laughter)

MR. BRUCE: Texaco did own interest in here until just a few years ago.

THE WITNESS: Right.

MR. BRUCE: They sold out just -- I don't remember the exact date, but they just sold out their interest.

EXAMINER JONES: Oh.

MR. BRUCE: Five years ago --

THE WITNESS: Five -- eight -- eight to ten years ago, yes.

Q. (By Examiner Jones) Real good gas wells, there's a few good gas wells in here. Are they included --

A. No, sir.

Q. -- below this unit?

A. Not -- not in this participating area.

Q. It's just Delaware only?

A. That's correct.

Q. And you noticed everybody within a half mile?

A. A half mile, yes, sir.

MR. BRUCE: And that was, of course, primarily for the injection --

EXAMINER JONES: Injection applications, okay.

Gail, do you have any questions?

MS. MacQUESTEN: I don't have any questions, thank you.

EXAMINER JONES: Okay, thanks, Ms. Wallace.

THE WITNESS: Thank you.

GLENN H. CURRY,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Will you please state your name for the record?

A. Glenn Curry.

Q. And where do you reside?

A. Midland, Texas.

Q. Who do you work for and in what capacity?

A. I work for Pogo Producing Company as senior geologist.

Q. Have you previously testified before the Division?

A. Yes, sir.

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

A. Yes, sir, they were.

Q. And are you familiar with the geology involved in this Application?

A. Yes, I am.

Q. Mr. Examiner, I tender Mr. Curry as an expert petroleum geologist.

EXAMINER JONES: Mr. Curry, you spell your name C-u-r-r-y?

THE WITNESS: Yes, sir, that's correct.

EXAMINER JONES: Mr. Curry is qualified as an expert petroleum geologist.

Q. (By Mr. Bruce) Mr. Curry, could you identify Exhibit 10 and discuss the -- maybe a little bit of the history of the development of this reservoir?

A. Okay. Exhibit 10 is a structure map on top of the Ramsey sand, which is the primary reservoir in this Paduca field. The field is located in Lea County, eight miles north of the Texas border and two miles east of the Eddy County line. It's in Township 25 South, Range 32 East.

It was discovered in 1960, and subsequently it was drilled -- 56 wells were drilled on 40-acre spacing. As I said, the primary producing reservoir is the Ramsey sand. It's a member of the Bell Canyon formation.

Minor production was recovered from the Olds sand, which is slightly deeper than the Ramsey.

It produced under primary recovery from 1960 until 1968, and at that time it was -- the waterflood began. And since that time it's continued to produce under waterflood. The production to date is over 14 million barrels of oil and 15 BCF of gas.

The field is a -- typical of many Delaware sand traps in the Basin. It's a northeast-southwest-trending

turbidite sand channel and it's overlying a structural nose. On Exhibit 10 you can see that generally the regional dip is to the east, and there's a structural nose evident -- it crosses in the north part of Section 21 and plunges to the east-southeast.

And the -- Exhibit 11 --

Q. Before you go on to that, you mentioned what has been recovered to date. What percentages of oil have been recovered in primary and secondary production?

A. Well, the original estimate -- well, the oil-in-place estimate is 61 million barrels of oil. Primary was 6 million, secondary 8 million, so primary is about 10 percent and secondary about 13 percent of the original oil in place. So that leaves a lot of reserves behind.

Q. Let's move on to your exhibits, maybe together 11 and 12 and you can describe the --

A. Sure.

Q. -- primary producing zone.

A. Okay, Exhibit 11 is a net sand isopach of the Ramsey sand, and it demonstrates that the sand reservoir trends from the northeast to the southwest. It continues both in the north and south directions. And on the updip western edge you have a pinchout of pay. To the east and southeast you have a pinchout or an oil-water contact that bounds it on the east side.

Both north and south, the sand does continue past the field limits, but it's bound by the oil-water contact in both directions. So it's a pretty typical stratigraphic sand trap.

Q. And these plats are based solely on well control in the area, correct?

A. That's correct. Exhibit 12 is a type log. It's taken from a recently drilled well, the Pogo Monsanto State 10, and that location is in the southeast of 16. And that well -- Well, I have a density neutron log here, and I have shaded in porosity greater than 20 percent, and I have -- the Ramsey sand in this well is 83 feet gross and about 50 feet of pay greater than 20 percent. The Olds is 58 feet gross and 32 feet greater than 20.

I have a blue bar indicated on the left side of the type log, which is the proposed stratigraphic interval that we are wanting to inject CO_2 in.

Q. Approximately how many productive acres are in this reservoir?

A. The productive area is approximately 2300 acres.

Q. What type of porosity and permeability are you looking at in this reservoir?

A. Okay, the oil in place is calculated for the Ramsey sand only. We consider the Olds a minor contributor. The permeability is much less in the Olds

sand, so the numbers I'm about to tell you relate to the Ramsey sand.

The porosity in the pay ranges from 15 to 28 percent, with an average of 24 percent.

The permeability, based from several core studies, varies from 1 to 100 millidarcies, with about a 20-millidarcy average. And the pay thickness of net sand greater than 20 percent porosity varies from zero to 72 feet, with an average pay thickness of about 30, 30 feet.

The original water saturation ranged from about 35 to 70 percent, with the average water saturation of about 45 percent. Many of the initial wells that were completed in the field did have 100-percent oil or very low water cuts, so...

And of course the reservoir engineer will cover this more thoroughly, but our estimated tertiary target is another 12 million barrels of oil, which would represent about 20 percent of our estimated original oil in place.

Q. And is the reservoir continuous across the participating area and the separate Monsanto State Lease?

A. Yes, sir, it is.

Q. And with respect -- and this goes to the injection application -- is there any faulting in this area which could connect freshwater sources with the injection interval?

A. No, sir.

Q. Let's move on to your Exhibit 13, and discuss a little bit the proposed development plan with respect to...

A. Okay. Well, Exhibit 13 is a base map with our acreage and the producing wells shown. I've indicated with a triangle the proposed locations for future injection wells. As I said earlier, the field is developed on 40 acres, and we intend to bring that down to 20-acre spacing with the drilling of injection wells.

We have it represented in a table, which is Exhibit 13A, which is simply a list of the locations and their footages, represents 57 well locations, of which all but two are new drills.

Actually, there's two conversions planned. One conversion is the new well, the Monsanto State 10, which is the type log, so it's essentially a new well. Really just only one conversion. All the injection wells will have new casing and new cement, et cetera.

Q. Now, Exhibit 13 lists the footages for the injection wells. Might some of these change in the future?

A. Yes, sir, I'd like to say that it's a preliminary pattern, preliminary plan. We're still doing some studies. Particularly, we're trying to understand the fracture direction. We've employed Pinnacle Technologies to do a fracture study in this new well. We're going to have an

array of geophone tiltmeters around the well. We're going to induce a frac hydraulically and try to determine the azimuth of frac propagation.

And based on that study and other subsurface study, we may want to change the orientation of some of these wells and move them. I would say this is the maximum number of injectors that we would drill. If we choose to eliminate some or even propose horizontal injectors rather than verticals, the number of wells may be reduced. But until we finish our study we won't know exactly how to place these and how to set up the play.

Q. Were Exhibits 10 through 13A prepared by you or under your supervision?

A. Yes, sir.

Q. And in your opinion is the granting of this Application in the interests of conservation and the prevention of waste?

A. Yes, sir, it is.

MR. BRUCE: Mr. Examiner, I'd move the admission of Pogo's Exhibits 10 through 13A.

EXAMINER JONES: Pogo Exhibits 10 through 13A will be admitted to evidence.

EXAMINATION

BY EXAMINER JONES:

Q. Mr. Curry, what direction do you think the

fractures are going?

A. Well, sir, I may refer that question to our reservoir engineer, because he's done a little more work on it. In the past history of the waterflood, there was some breakthrough in an east-west direction --

Q. Okay.

A. -- so we're conscious of that. But we'd like to -- we know that the pressure regimes have changed in the field through the years, and we just want to know how is it today.

Q. How is it regionally, though? I mean, as a geologist, how -- in other fields, in other -- even down in the Geraldine Ford stuff down in Texas, does that have any kind of linearity to it?

A. It's generally an east-west or northeast-southwest, I believe. Of course Dan may correct me on that. He's studied it a lot more and talked to a lot more --

EXAMINER JONES: He says he's not going to.

(Laugher)

Q. (By Examiner Jones) He's wanting you to commit.

A. Yeah. Well, we certainly want to avoid --

Q. -- breakthrough.

A. We want to try to be -- have our injection parallel to that trend so we don't have breakthrough --

Q. Okay.

A. -- prematurely. And we're just trying to do our homework, nail it down before we spend all this money.

Q. Yeah, it looks like you're going to spend a lot of money here.

A. Lot of money.

Q. Lot of money. As far as isolating these injection wells from the salt zone, what have you got? 200 feet? 250 feet from the salt? So you're not worried about it getting up in the salt. You're going to have all new injection wells --

A. All new --

Q. -- good cementing --

A. -- good cement, right.

Q. As far as that Olds sand, you don't expect it to take much CO_2?

A. Well, as an example, the permeability in this well, the type log -- you know, the average perm in the Ramsey is 20 millidarcies, average perm in that Olds sand is like 3 millidarcies. So we think preferentially it's going to be hard to treat --

Q. Yeah.

A. -- hard to process with CO_2. And apparently it's contributed some in the waterflood, but a minor amount compared to the Ramsey.

Q. Okay. And we hope we get some added reserves from the Olds. We definitely are going to drill through it and evaluate it. We know that the oil-water contact for the Olds is -- it doesn't extend all the way across the field. The best production is on the west half of the field, so we know it won't be a target all the way across.

Q. Okay.

A. But we're not going to neglect it, we're going to try to exploit it if possible. And we haven't -- but of course our -- all of our economics and all of our justification for the project is based on the Ramsey, which is the primary objective.

Q. Okay, it looks like you're going to a smaller spacing on your actual overall well count?

A. Yes, sir.

Q. As a geologist, do you agree with the -- is that needed as far as -- not from a reservoir-engineering standpoint, but from a discontinuity/heterogeneity standpoint in the reservoir?

A. Well, the depositional environment is the deep-water marine turbidite sands, which is really a series of multiple sand flows, gravity flows, of very fine sand. Generally, it's a sand-rich environment where each flow is in contact with the other, and there may or may not be continuity through there. We've seen examples of both

where you have continuity for some distance, and maybe in a direction normal to that it might not be that continuous. So we feel it's necessary to drill 20-acre spacing to get better efficiency in processing the rock.

Q. Okay. Does this turbidite marine fine-grain sands -- does that have any sort of coarsening-upward characteristics on it, or --

A. Well, sir, it is a very, very fine sand. I've examined cores, and you seldom get above a 175-micron grain size. This is -- You know, we're probably 20 to 25 feet from the -- 20 to 25 miles from the source rock. We're in deep marine. It doesn't have enough velocity to carry large grain sizes. So your range of grain sizes from clay size to upper silt, lower very fine grain.

Q. Okay.

A. So you do have some coarsening-downward sequences, but generally it's pretty homogeneous. You'll have silty, shaly sands, separated with suspension deposits of clay-size material, which may or may not be a barrier. Sometimes they're not barriers, they're just baffles that slow the --

Q. Oh.

A. -- it impedes the permeability and transmissibility. So it's a big pile of sand --

Q. Okay. Where's the source of the oil?

A. It's the platform 25 miles northeast. It's well documented that -- this particular channel is mapped over about a 25-mile area, and it's periodic pulses of sand that go down this defined channel, and they just fill in and slide and plow into each other and just fill this channel valley full of this silt sand.

Q. Where would be the best example of the best Ramsey sand in the -- is it -- would it be down in the Geraldine Ford field, or would it be -- is this one of the best ones that a person could find?

A. Well, it's a pretty nice sand. You know, we're up in the -- about 20- to 28-percent porosity. That's pretty good. The permeability looks pretty good. So it's a pretty nice project.

Q. Okay.

A. It compares with the other fields that have been waterflooded and CO_2-flooded. There's problems with this kind of sand.

Q. Now, do you -- Do logs tell you anything, or do you have to core this stuff?

A. We're fortunate in this field that the earlier operators -- I think there's about 32 cores cut in this field. We have reports on about 20 of them, so we have that porosity and perm data.

The logging suite used out here in the past was

sonic logs. The resistivity logs are not as common. So -- But since we do have enough core data, we have a pretty feel for the porosity. By the time we drill it out and run modern logs, we'll have a lot better data. We intend to core three or four more wells and do some lab work on --

Q. Whole cores?

A. Yes, sir, we have one whole core on this new well, and we're currently doing studies on it. We've identified the mineralogy and the clays, and we're doing some special core-analysis studies in the lab currently --

Q. Okay.

A. -- and --

Q. Okay.

A. -- I'm stealing Dan's thunder --

Q. Yeah.

A. -- here. He can really help you with that. But we think it's a good project.

Q. Okay. You must be willing to spend some money now.

I guess the biggest question I've got is, you said it was -- to the east you have increasing water saturation.

A. Well, I was discussing the boundaries of the field, what defines the field limits. And as you can see on the -- we do have field pinchout limits in most areas.

However, up in the northeast, you have kind of a splay of sand that goes past, over into Section 14, so...

Q. In the Ramsey?

A. Yes, sir, this is a Ramsey map.

Q. Okay.

A. So what I was saying is, the boundary to the east is either a pinchout of sand, or you encounter the oil-water contact as you proceed downdip.

Q. Okay. So if you CO_2 -- I think I remember you can CO_2-flood areas higher in water saturation than you can successfully waterflood.

So are you considering expanding this to the west a little bit?

A. To the west?

Q. To the east, I'm sorry.

A. To the east? No, sir.

Q. So that would be --

A. We're just going to go with --

Q. -- going to go with what you've got?

A. -- go with what we've got.

Q. Yeah.

A. And flood that.

EXAMINER JONES: Okay, that's all I have. Gail, do you --

MS. MacQUESTEN: No questions.

EXAMINER JONES: Thanks a lot, Mr. Curry.

DAN STOELZEL,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Could you please state your name for the record?

A. Yes, sir, my name is Dan Stoelzel.

Q. Could you spell your last name for the Examiner?

A. That's spelled S-t-o-e-l-z like zebra -e-l.

Q. Where do you reside?

A. I reside in Midland, Texas.

Q. Who do you work for and in what capacity?

A. I'm a district reservoir engineer for Pogo Producing Company.

Q. Have you previously testified before the Division?

A. No, I have not.

Q. Could you please summarize your educational and employment background?

A. Yes, sir, I got my bachelor's degree at Texas Tech University in 1985, master's degree in petroleum engineering from Colorado School of Mines. I've been working in the industry since 1987, mostly as a reservoir engineer. The last ten years or so of my career has been

pretty much strictly in the Permian Basin west Texas-New Mexico area.

Q. How long have you been employed by Pogo?

A. A little over a year.

Q. And does your area of responsibility at Pogo include this part of southeast New Mexico?

A. Yes, sir.

Q. And are you the engineer in charge of the CO_2 flood for this project?

A. Yes, I am.

MR. BRUCE: Mr. Examiner, I'd tender Mr. Stoelzel as an expert engineer.

EXAMINER JONES: Mr. Stoelzel is qualified as an expert petroleum engineer.

MR. BRUCE: You first -- Let's go through the C-108, the injection Application, first, which is marked Exhibit 14.

Mr. Examiner, if you'll look at the -- it's paper-clipped together. There's a few different sections, and if you took off the biggest paper clip, it might be easiest to go through it that way.

The first exhibit is a -- or the first section of this is a land plat, Mr. Stoelzel. What does that reflect?

A. This just reflects the area of interest with boundaries showing offset acreage, and I think the red line

represents the half-mile radius for the injection permit reasons --

Q. Okay --

A. -- you know, reasons.

Q. -- and so you looked at all wells within that red line?

A. Yes, I have.

Q. Okay. Let's move on to the second section, which is item Roman numeral VI of the C-108, the wells in the area of review. Could you just briefly go through that and discuss whether there are any wells that need remedial work before injection begins?

A. Most of these wells -- Currently there are about 12 active injectors and about 12 active producers. There are several shut-in producers, but the majority of the wells are either TA'd or P-and-A'd. And most of them were P-and-A'd were done under the regulations -- when Texaco operated the field, they P-and-A'd quite a few back in the 1980s and again back in the mid-1990s and, you know, set cement plugs and whatnot, according with the rules.

We've reviewed all the wells, and we feel like they've all been P-and-A'd appropriately, and currently there are no problem wells.

Q. Okay. And behind this section is -- all of the -- the thickest section of this contains information on all

the plugged and abandoned wells, does it not?

A. Correct.

Q. And again, your review shows that they're all properly plugged and abandoned?

A. That is correct.

Q. And from what you've seen, there's no chance of any migration of fluids that would violate Division rules?

A. No, sir.

Q. Could you discuss the typical wellbore for your proposed injectors?

A. Yes, one of the last pictures in the thick packet would be a pretty straightforward completion. Surface casing would be set around 750 feet, which will protect all the surface fresh waters. And both casing strings, surface as well as a production string, will be cemented to surface.

Q. And this is the type of program that was used on the recently drilled Monsanto 10 State --

A. That is --

Q. -- or Monsanto State Number 10 well; is that correct?

A. That is correct, yes.

Q. Now, on this well plat it shows -- or well schematic, it shows the wells being drilled to approximately 5000 feet. Again, you are in the upper

Delaware at that depth?

A. That is correct.

Q. And what is the approximate base of the Delaware?

A. The base of the entire Delaware section is at about 8500 feet, but the injection interval for the CO_2 project is defined under various leases but generally goes down to about 5000 feet, which gets you through the Ramsey and Olds sections.

Q. Okay. Above the Ramsey sand, are there any productive intervals in this area?

A. No, sir, there are not. The anhydrites are pretty much right above.

Q. Could you go over the items 7, 8 and 9 of the C-108 with respect to the operational data, and discuss the injection rates, et cetera?

A. Yeah, where is that? Yeah, we're proposing, currently, rates of 1000 barrels of water a day and/or 1000 -- you know, 1 million standard cubic feet of CO_2 a day, or 2 million -- 1 to 2 million, I believe, for a vertical well, vertical injector, injection pressures not to exceed 500 for the water and estimated to be about 900 pounds for the CO_2 injectors.

Q. And is there a stimulation program proposed for these wells?

A. For the injectors, we're still evaluating that,

and that's going to be based on the stiltmeter study we're doing. If we do -- In the past these producers have been frac'd, but the fracs are generally very small, on the order of 15,000 to 20,000 pounds, and I think they generally frac'd them to basically hook up the sands near the wellbore. It wasn't necessarily frac'd for extension to get rate. And if we do frac any of the injectors, it would certainly be on that order, just to connect up sands.

But currently we're evaluating that, you know, and that's an ongoing science project right now, as it were.

Q. With respect to the injected water, where does that come from?

A. Most of it is produced water from the flood. If we do need makeup water, we have a freshwater well that we can mix in with the produced water and treat accordingly, but we don't anticipate the need for very much makeup water.

Q. Where is the nearest freshwater well in this area?

A. I believe it's about six miles away, and Pogo also owns that well, and it's currently being used by the local ranchers out there to water their cattle. And that's also included in the exhibits. There's a --

Q. And a --

A. -- water analysis --

Q. -- freshwater analysis --

A. Right.

Q. -- is included?

A. Yes.

Q. You mentioned there's about a dozen producing wells out there. What is the production?

A. The current production for the entire area, which includes the Cotton Draw Unit and Monsanto State Lease, is between 50 and 60 barrels a day right now. So you're looking at less than five barrels a day on average, per producer.

Q. Okay. They are definitely stripper wells under the various regulations?

A. Definitely stripper, it's a worn-out old waterflood. There's not much left in conventional recovery methods, that's for sure.

Q. Okay. Let's discuss the cost of this project. Could you identify Exhibit 15 for the Examiner?

A. Certainly, Exhibit 15 is a very brief rundown of what we estimate to be capital costs and returns from the CO_2 flood. Capital costs amount to about $35.5 million, which includes a CO_2 trunk line, workovers, drill wells, and about $13 million in recycle facilities.

We anticipate, as Glenn mentioned earlier,

recovering about 12 million barrels from the CO_2 total gross, and I've thrown a little bit of NGL recovery in there that we'd probably get from the recycle facilities. You know, when you factor in the lease operating expense and the capital, you know, your incremental value, a little over 400 million barrels, we anticipate.

Q. On the project cost you have pipeline, fairly substantial item. There is no CO_2 pipeline in this area; is that correct?

A. That is correct. There's a supply line about seven miles south of this area that supplies the El Mar and used to supply the Ford Geraldine, and I think it supplies a little bit of CO_2 gas to the East Ford Unit, and that's operated by Kinder Morgan. As it stands now, though, we've contacted them and they have no supply capacity remaining to that area.

So we are currently investigating other sources of supply CO_2 further north. We're in discussions with both Kinder and ExxonMobil, who are the two major suppliers, and we're looking at various options to capture that CO_2 from some of the larger supply lines to the north.

Q. So a substantially long pipeline will have to be built?

A. That is correct, and that cost is not in here, the $4.5 million pipeline cost is just a trunkline to

probably tap into that system.

Q. Okay. Let's go into your anticipated recoveries, maybe just go to Exhibits 16 and 17 together --

A. All right.

Q. -- and discuss historic production and what you anticipate or hope to recover.

A. Very well. The Exhibit 16 is a fairly busy plot showing historical production from oil, gas, water, as well as water injection. As you can see, the production started in late 1960, early 1961. In 1968 it was unitized for waterflood, and that's when they started injecting water, you can see by the light blue line.

You see a bump in production toward the end of 1970, and that is partially due to waterflood response, but as I went through the records the operator at the time, which I believe is Texaco, put in a fairly comprehensive stimulation program where they went in and frac'd most of their producers, because they had previously just been stimulated with acid. And so some of that jump from about 1000 barrels a day to about 2500, 2600 barrels a day is due to workover stimulation.

And then as you go into 1973-74 time frame, you another little bump, and I think that's probably more representative of the true waterflood response, because if you look at the GOR plot, you know, you don't -- you fully

collapse your gas sometime in late 1975-76. That's where the GOR tends to level off. So I feel like from that point on it's probably more representative of waterflood response.

And then if you go to Exhibit 17, the last plot, it shows kind of the tail end of primary -- or secondary production, rather, with what I anticipate to be the tertiary CO_2 response. We plan on having CO_2 available in late 2006 or early 2007, and we anticipate about a three- or four-year response period, with the peak response coming, you know, sometime in probably 2009 or 2010 at, oh, close to 5000 barrels a day, and then declining from there.

Q. Will the tertiary project result in an increase in the amount of crude oil ultimately recovered from the reservoir?

A. Yes, sir, it will.

Q. And in your opinion, is it prudent to apply enhanced recovery techniques to maximize ultimate recovery of oil from the pool?

A. Yes, sir.

Q. And in your opinion, is the CO_2 project economically and technically feasible at this time?

A. At this time all indications are, it should be a very good CO_2 project.

Q. Were Exhibits 14 through 17 prepared by you or

under your supervision?

A. Yes, sir.

Q. And in your opinion, is the granting of this Application in the interests of conservation and the prevention of waste?

A. Yes, it is.

MR. BRUCE: Mr. Examiner, I'd move the admission of Exhibits 14 through 17.

EXAMINER JONES: Exhibits 14 through 17 will be admitted to evidence.

EXAMINATION

BY EXAMINER JONES:

Q. What did you get your master's -- what was your option in the master's program?

A. It's a master of science, I did do thesis work.

Q. Did you specialize in a certain -- reservoir engineering?

A. Actually, my thesis project pertained to waterflood experimentation, and some tertiary-type studies.

Q. I just wondered, it seems like you're really doing your homework here. Is your team the one that had to sell it to management, sell this project to management?

A. Pretty much the team is me for CO_2 flood at Pogo right now, so it better work.

MR. CURRY: We're right behind you.

MS. WALLACE: We're right behind you.

(Laughter)

Q. (By Examiner Jones) Guess you've got a lot going here. I won't belabor this a whole lot, but your injection-withdrawal ratio right now, as far as -- Are you worried about losing any CO_2 out of zone?

A. That is a concern. I think there's more of a concern of losing it out the channel to the north and south. And I plan to set up, you know, water blanket injection wells to kind of close off those escape paths, as it were, use water injectors. Because we're drilling all new injector wells, we -- you know, in a CO_2 flood obviously you don't want to lose any of it, it's pretty expensive stuff. So we're going to try as best we can to contain the injection within the flood intervals.

And that's another reason why we're pretty much -- well, every one of our injection wells is going to be a new drill, so we know we'll have cement and casing integrity.

Q. Did you run a model to get this prediction, or do you just base it on a certain percentage original in place and --

A. It's actually a model, but it's an analog model. We're currently doing the science. I plan to run a simulation, but that's probably going to be sometime next

year before that's completed.

But to get the ball rolling and to get a first look at CO_2 requirements, I actually developed an analog model based on the CO_2 response from the Two Freds field, which is probably the most successful Ramsey sand CO_2 flood currently. And I --

Q. Where's that one at?

A. That's actually down in Texas, in Loving and Ward Counties. I think it's about 60 miles -- pretty much due south of the Paduca field. And it was an old waterflood that was CO_2-flooded back in 1974, one of the first CO_2-floods in the Permian Basin. And it was very successful.

And I believe it could have been more successful, but they were using CO_2 from tail gas coming from some of the processing plants in the area, and in the 1980s, going into the late 1980s, into the 1990s, those plants started to drop off in, you know, production processing. So they lost a lot of their CO_2 supply.

Q. This processing of CO_2, are you going to recycle your gas stream, or are you going to --

A. Yes, we --

Q. -- strip it out?

A. -- we -- probably -- you know, I've got some CO_2 experience. Before I worked with Pogo I worked with OXY and was involved in some of their floods. And typically

what the industry is leaning towards now is, when you start to get enough contaminated gas coming from your production system, you just turn it back around and re-inject it, you know, blood, guts and feathers, until you reach a point where you can no longer -- you endanger maintaining miscibility. And at that point you probably -- you have to go and put in some sort of NGL-recovery-type facilities to pull some of those hydrocarbons out of the produced gas stream.

And that's sort of what we're planning. We'll probably initially just go with recycle, and at some point we'll have to start stripping out the NGLs to, you know, purify up the CO_2 stream, as it were. And that's all -- hopefully, we'll be a little bit more -- the timing of all that, hopefully, will come out of some of the more detailed studies I plan to do.

Q. As far as those detailed studies, the special core analysis, are you going to get your capillary pressure curves and your --

A. Yes, sir, we're --

Q. -- saturation --

A. -- we've got all that going with the new core we've cut, and we plan to do that with the -- Like Glenn said, I think we've got three or four more wells planned to cut some cores. We're just waiting on the permits to be

approved.

Q. When would have been the best time to start CO_2 in this flood to get the best recovery out of this reservoir?

A. That's a good question. You know, there's various studies that have shown that some rocks will recovery incrementally more under CO_2 flood before you get too far into a waterflood, and some studies showing that, you know, recovery -- ultimate recoveries aren't that much affected, you know, if you're at the later stages of a waterflood. And from what I remember, those cases were typically carbonate floods where companies have gone in and CO_2-flooded old waterflood carbonate reservoirs, recoveries don't seem to be affected.

But in sandstones, from what I remember in the literature, it's now believed, I think, that if you start your CO_2 floods a little bit earlier you might gain incrementally more reserves. So -- We're kind of past that point out here, so we're going to obviously live with what we get.

And that's another reason we're drilling new injectors, to help sweep efficiencies and to overcome some of that if we can.

Q. Okay, so -- And the pattern is going to be a 20-acre well-spacing; is that right?

A. Yes.

Q. Forty-acre fivespots?

A. Yeah -- we're looking at various options; fivespots are where we're going now.

But we feel that, based on what we see with the fracture work -- and when we say "fractures", we don't see any evidence, *per se*, in the core of natural fracturing, but we do know that there's probably induced fracturing, because -- You know, if you can see by the curve here, if you look at the IWR plot, through the -- all through the 1970s and into the mid-1980s, you know, you've got IWRs, in some cases more than two to one. And I feel that probably there's quite a bit of induced fractures coming from those old injectors, and we want to try and manage the flood such that we, you know, avoid those and go parallel to those as best we can.

And so -- So I say 20-acre wells. You know, it probably will be something like that, but the exact pattern alignments, it might be more of a line drive versus a fivespot and that sort of thing.

Q. Or even possibly horizontal injections?

A. We're looking at that, yes.

Q. So you've still got a lot of studying to do, it looks like.

A. Right, right.

Q. And you'll have a full staff of equipment engineers and --

A. Yup, yup, our operations group is trying to get that staff in place right now, actually.

Q. Okay. Well, the graph that you're projecting for CO_2, that would be the projected qualification for the EOR, or the tax credit --

A. (Nods)

EXAMINER JONES: Okay, I think that's about the only questions I should be asking at this point.

Okay, thank you very much, Mr. Stoelzel.

MR. BRUCE: I have nothing further in this matter, Mr. Examiner.

EXAMINER JONES: Thank you, Mr. Bruce.

With that, we'll take Case 13,581 under advisement, and good luck with your project.

MR. STOELZEL: Thank you.

(Thereupon, these proceedings were concluded at 10:10 a.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. _____ heard by me on _____.

_____, Examiner
Oil Conservation Division

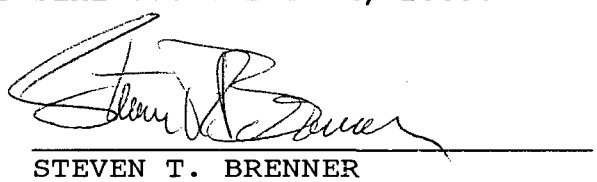
CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

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

WITNESS MY HAND AND SEAL October 28th, 2005.



STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2006