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 CHESAPEAKE OPERATING, INC., FOR STATUTORY UNITIZATION OF THE TRINITY BURRUS UNIT AREA, LEA COUNTY, NEW MEXICO	CASE NOS. 13,582
APPLICATION OF CHESAPEAKE OPERATING, INC., FOR APPROVAL OF A WATERFLOOD PROJECT AND QUALIFICATION OF THE PROJECT AREA OF THE TRINITY BURRUS UNIT FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE ENHANCED OIL RECOVERY ACT, LEA COUNTY, NEW MEXICO	and 13,583
	(Consolidated)

2005 NOV 3 PM 5 45

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

ORIGINAL

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 NOS. 13,582 and 13,583 (Consolidated)

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EXHIBITS

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A P P E A R A N C E S

FOR THE DIVISION:

GAIL MacQUESTEN
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FOR THE APPLICANT:

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By: WILLIAM F. CARR

* * *

WHEREUPON, the following proceedings were had at 12:36 p.m.:

EXAMINER JONES: Okay, let's go back on the record this afternoon and call Cases -- I assume you want to combine the cases?

MR. CARR: Yes, sir, if we could consolidate the Chesapeake Applications.

EXAMINER JONES: We'll call Case 13,582 and Case 13,582.

13,582 is the Application of Chesapeake Operating, Incorporated, for statutory unitization of the Trinity Burrus Unit area, Lea County, New Mexico.

And Case 13,583, Application of Chesapeake Operating, Incorporated, for approval of a waterflood project and qualification of the project area of the Trinity Burrus Unit for the recovered oil tax rate pursuant to the Enhanced Oil Recovery Act, Lea County, New Mexico.

Call for appearances.

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe office of Holland and Hart, L.L.P. We represent Chesapeake Operating, Inc., in these cases, and I have three witnesses.

EXAMINER JONES: Any other appearances?

Will the witnesses please stand to be sworn?

(Thereupon, the witnesses were sworn.)

TERENCE A. FROHNAPFEL,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?
A. My names is Terence Alexander Frohnapfel.
Q. Would you spell your last name?
A. F-r-o-h-n-a-p-f-e-l.
Q. Mr. Frohnapfel, would you tell the Examiner by whom you are employed?
A. Chesapeake Energy Corp.
Q. And where do you reside?
A. Oklahoma City.
Q. What is your current position with Chesapeake?
A. Petroleum landman.
Q. Have you previously testified before the Oil Conservation Division?
A. No, I haven't.
Q. Could you summarize your educational background for the Examiner?
A. College degree, Oklahoma State University, business major.
Q. Since graduation for whom have you worked?
A. I have 20 years' experience in the oil and gas,

all landman-related.

Q. And how long have you been with Chesapeake?

A. Been with Chesapeake, it'll be one year in December.

Q. Are you the land person responsible for the unitization of the Trinity Burrus Unit area?

A. Yes.

Q. And are you familiar with the Applications filed in each of these consolidated cases?

A. Yes, I am.

Q. Are you familiar with the status of the lands involved in the proposed Trinity Burrus Unit area?

A. Yes.

MR. CARR: We tender Mr. Frohnapfel as an expert in petroleum land matters.

EXAMINER JONES: Mr. Frohnapfel is qualified as an expert in petroleum land matters.

Q. (By Mr. Carr) Would you briefly state what Chesapeake Operating seeks in this case?

A. Chesapeake seeks statutory unitization of the proposed Trinity Burrus Abo Unit, 1720 acres, and approval of the waterflood project in the unit area and the qualification of the project for the incentive tax rate.

Q. Could you identify for the Examiner what has been marked as Chesapeake Exhibit Number 1?

A. Okay, that's the area map, and it shows which -- Are you needing one?

EXAMINER JONES: I might have them in here.

MR. CARR: No, they're in the -- Aren't they in the accordion file?

EXAMINER JONES: Oh, here we go. I'm sorry. They're right there.

MR. CARR: We'd like to keep you in the dark, Mr. Examiner.

(Laughter)

Q. (By Mr. Carr) All right, Terry, identify Exhibit 1.

A. Okay, just shows the portion of the pool that's subject to the hearing, shows the unit boundary --

Q. Shows the tract numbers in the unit area?

A. It does show the tracts. It should be 28 tracts.

Q. What is the character of the land in this unit area?

A. It's seven-percent federal, 23-percent state and 70-percent fee.

Q. Would you identify what has been marked as Chesapeake Exhibit 2?

A. Okay, that's the unit agreement that's provided by the -- it's a State Land Office form, and it shows character of the lands, how it breaks down, federal, state, fee, different provisions providing for waterflooding. Sets out the basis for the formulas for the tract participation and just other -- other exhibits.

Q. Does unit agreement provide for the filing of periodic plans of development?

A. Yes.

Q. And will those plans be filed with the OCD at the same time they're filed with the land office and the BLM?

A. Yes, they are.

Q. What is Exhibit Number 3?

A. It shows the participation in the unit by tract.

Q. And the tract numbers are shown on the left and the participation on the right, and you can go back to Exhibit 1 and you can see how that breaks down; is that correct?

A. Right.

Q. What is the basis -- Is the basis for the participation, did you say, set out in the unit agreement?

A. Yes.

Q. And we will be calling an engineering witness to review the tract participation for the Examiner?

A. Yes.

Q. Is Chesapeake Exhibit Number 4 the unit operating agreement?

A. Yes, it is.

Q. Is Chesapeake recommending an amendment to the unit operating agreement?

A. Yes.

Q. Is that amendment set forth on Chesapeake Exhibit Number 5?

A. Yes.

Q. Mr. Frohnapfel, we actually got a protest to this Application, did we not?

A. Yes, we did, from Rehoboth, Inc.

Q. And they filed an objection with the Oil Conservation Division?

A. Correct.

Q. And we have reviewed their protest; is that also correct?

A. Correct.

Q. What they were requesting was an amendment to a certain provision. Can you tell me what provision in the agreements they were concerned about?

A. It was the number 3 provision in Exhibit 5.

Q. In Exhibit G.

A. Exhibit G.

Q. And was that to the unit operating agreement?

A. Just strictly to the unit operating agreement, not the unit agreement.

Q. And we have talked with the representatives of

Rehoboth?

A. Right, and we have resolved the protest, and they've agreed to drop.

Q. And the Exhibit Number 5, Chesapeake 5, the amendment to the unit operating agreement, that amendment is acceptable to Chesapeake, is it not?

A. Yes, it is.

Q. And it's acceptable to the parties who were protesting?

A. Yes.

Q. When we look at this, this amendment is designed simply to assure that any tract encumbered by an earlier joint operating agreement with a different risk penalty, that that would survive the unitization and those old risk penalties would apply; isn't that right?

A. That's correct.

Q. How much of the total unit participation are we talking about here?

A. We're only talking about one half of one percent.

Q. And what impact would this amendment have on any other working interest owner?

A. It would have no impact on any other interest owner, working interest owner.

Q. It is, however, an amendment to the unit operating agreement, which is a contract between the working interest owners, is it not?

A. Yes.

Q. It has no on royalty owners, they wouldn't sign this agreement?

A. Right.

Q. And we are going to ratify the agreement by the working interest owners, just to be certain everyone is on board with this change; is that not right, Mr. Frohnapfel?

A. That's correct.

Q. Have you agreed to meet with the protestants to resolve any other issue raised in their protest?

A. Yes, we have.

Q. Okay, let's go to the unit operating agreement, and I'd ask you just generally to review the key provisions that you find in the agreement.

A. Okay. It's kind of like a joint operating agreement except bigger, and it outlines supervision by the unit operator and how to manage the unit and defines the rights of all the parties. It shows the investments and costs, how they're to be shared, and establishes voting procedures. There's the creation of an operating committee that overlooks cost and sets out accounting procedures like a normal JOA would, with the COPAS, and just contains other provisions, just standard provisions.

Q. In fact, this unit operating agreement is really an agreement that defines how the working interest owners will deal with each other throughout the life of the unit; isn't that right?

A. That's correct.

Q. When did Chesapeake first start putting this unit together?

A. First started the early part of June of 2005, and that's when we first made contact with the interest owners, alerting them that we had an upcoming working interest owners' meeting June 24th, which we had about -- close to 90 percent of the interest owners, the working interest owners, did show up and had questions. And we just went through the plan and the engineering, geology, so...

Q. Since that time have you had meetings with individual interest owners in the unit area?

A. We have had some meetings with some of the working interest owners, talking about some of the things that they wanted changed, and we did make the changes before we submitted the last Application, other than the previous thing that we talked about that involved Rehoboth.

Q. Did you also review the proposal with the BLM and the State Land Office?

A. Yes, we have.

Q. When did you actually send out ratifications to the working interest owners and to the non-cost-bearing interest owners in the unit area?

A. August 31st, we sent out a packet to all the interest owners, asking them to ratify the plan. Royalty owners just received the unit agreement, and working interest owners received both working interest -- I mean, the unit agreement and the operating agreement.

Q. Since the mailout of these documents, have you also been talking with various interest owners by telephone?

A. Yes, we have.

Q. And all of the interest owners were also notified of today's hearing and supplied with an additional copy of the unit agreement and the unit operating agreement; isn't that correct?

A. That's correct.

Q. Is Exhibit Number 6 a copy of the August 31st letter, two letters dated that date, by which you solicit the support of the other interest owners?

A. Yes.

Q. What is Chesapeake Exhibit Number 7?

A. Okay, that's the letter from the BLM showing that they've reviewed the plan, they've approved -- they did approve our plan, and they're -- it's set for final approval.

Q. And what is Exhibit Number 8?

A. It's the letter from the Commissioner of Public Lands, and it also approved our plan. It's set for final approval also.

Q. There are some changes that have been requested by the Commissioner of Public Lands that relate to how you number and organize the tracts. Is there anything in those requirements that change anyone's interest in the --

A. No.

Q. These are standard changes, just to get these tracts consistent with their format?

A. Right.

Q. Let's go to Exhibit Number 9, the working interest owner participation list. Would you explain what this is?

A. Okay, it's a list that just shows the working interest owners how much their interest is after the tract participating formula has been used, so you can -- that's what their interest will be, how much they'll be charged on the total of the tract, and --

Q. Some of the --

A. -- and -- Pardon me?

Q. Go ahead.

A. Okay. -- and we have received responses from 23 of 29. There are six of them that they do know about it. I think four out of six did come to the meeting, but there's various reasons why they haven't committed.

Q. And the interest owners shaded in yellow are those who have committed to the unit at this time?

A. Correct.

Q. Down toward the bottom of this exhibit is an entry called "Unleased". What does that indicate?

A. Okay, the unleased portion or -- it represents royalty owners that never did lease, so there was no way you could create a working interest owner out of that. And we today are still trying to lease them, and we've been in that area for several years, and we've got probably over a year's worth of trying to locate them.

It was a bigger number at one time, but we've whittled it down to -- I think there was about 14 people that -- right now, that are unleased.

Q. And in fact what we have is, we have just fee mineral owners that haven't leased anyone; isn't that right?

A. Not that they're opposing to lease, they just aren't findable, and we tried to find them through different sources, talking to other working interest owners -- or -- working interest owners, you know, getting pay decks off of them and seeing if they're in other areas around there, talking to some of the royalty owners, you know, that might be in the same tract, and checking on the

Internet, and of course start with courthouse records and go from there.

Q. Some of them we do have some addresses for; isn't that right?

A. We do have, but they've come back to us as bad addresses.

Q. So what we have done in regard to these interest owners, as in the notice affidavit that we'll get to in a few minutes, you will see that they are indicated after their name as unleased. These are the owners of the fee estate, there is no lease, so they have the working and royalty interest role, but to complete this table and get it to 100, the very small interests that these people held were grouped together and appear in that column.

So they do have some working interest, they would have some royalty interest, but they are all unleased and they have all been notified to the extent we can find them.

Let's go now to Exhibit Number 10. What is Exhibit 10?

A. Okay, it's a list of all the royalty owners. It shows -- the ones that are highlighted shows which ones are committed that have approved the plan assigned ratifications. The ones that are not highlighted, those are the ones that just haven't responded yet. We haven't had any of them disapprove of the plan, it's just -- they haven't responded, and we're still attempting to locate them. And we have received a few that were returned -- return to sender, bad addresses.

So just, you know, still searching the records, courthouse records, Internet search, and, you know, talking to people that are already signed up to see if they might know them. So...

We've been in that area for, you know, a couple years, and we're always on the hunt for them.

Q. And the interests that have signed are shown in yellow, right?

A. Right.

Q. Now, what percent of the working interest ownership is presently committed to the unit?

A. Working interest --

Q. Yes.

A. -- ownership is at 94 percent.

Q. And what percentage of the royalty or non-cost-bearing interest has voluntarily joined?

A. We've got 73.5 percent.

Q. Does that include the state and federal government royalty?

A. No.

Q. And if they are -- once they ratify, what level of ratification are you as to these non-cost-bearing interests?

A. We'll be at 91 percent.

Q. Do you believe you've done all you reasonably can do to obtain voluntary commitment to the unit?

A. Yes.

Q. And have you made a good-faith effort to secure the voluntary unitization of all the working interest owners and royalty interest owners in the area?

A. Yes.

Q. Can you identify for me Chesapeake Exhibits 11 and 12?

A. Those are the affidavits confirming that notice of the Applications have been provided in accordance with the rules of OCD.

Q. And to whom was notice provided?

A. All the interest owners, the working interest owners and non- -- you know, all the non-cost-bearing interest owners.

Q. As to the waterflood project, who was notified?

A. Everybody -- all leasehold operators within a half mile of the seven proposed injection wells, and of course the surface owners.

Q. Were Exhibits 1 through 12 either prepared by you or compiled under your direction and supervision?

A. Yes, they were.

MR. CARR: At this time we would move the admission into evidence of Chesapeake Exhibits 1 through 12.

EXAMINER JONES: Chesapeake Exhibits 1 through 12 will be admitted to evidence.

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

EXAMINER JONES: Okay. Do you have any questions on the notice?

EXAMINATION

BY EXAMINER JONES:

Q. I guess for my edification here, the unsigned mineral interest owners -- or unleased mineral interest owners, how would you treat them? Do you carry them, then, if you can ever find them?

A. We -- Normally, we would carry them, and any of those moneys that would be going to them would end up being set up in an escrow account in the State of New Mexico, would end up -- after so many years, it would be just like, I guess, on the pooling.

Q. So like a compulsory pooling?

MR. CARR: Yeah.

THE WITNESS: Uh-huh.

Q. (By Examiner Jones) And statutorily, it's 7/8 royalty?

THE WITNESS: (No response)

MR. CARR: Mr. Frohnapfel, let me ask one more question.

THE WITNESS: Yes.

MR. CARR: As to these interest owners who are unleased, if they are treated as a 1/8-7/8 mineral owner, 1/8 being treated as royalty and 7/8 as working interest, would Chesapeake request that the 200-percent risk penalty be assessed against the interest owners, or having to carry --

THE WITNESS: Probably the 200 percent.

MR. CARR: If I can answer, I mean, it would be treated just like a -- similar to a compulsory pooling situation, a 200-percent penalty, and you'd break those people out for accounting, 7/8 working, 1/8 royalty, and treat them that way.

EXAMINER JONES: Okay.

Q. (By Examiner Jones) The notice, as far as the injection, to all the offset operators -- now, you've got a newspaper notice in here too, and did that include the wording that there was going to be injection going on? I'm sure it did, but --

A. They've got a copy of the --

Q. We've got it right here.

A. They didn't get a copy of the Application, but they received a copy of the -- just the notice and that there would be a hearing, in case they had any opposition.

MR. CARR: It says there will be injection into the Wolfcamp through seven injection wells --

THE WITNESS: Okay.

EXAMINER JONES: Is that the Wolfcamp zone that's going --

MR. CARR: We're going to have a geological witness --

EXAMINER JONES: Okay.

MR. CARR: -- who's going to get into that, because that is a good question.

Q. (By Examiner Jones) Okay, let's see here. So it sounds like you've done a lot of work from June until now, and you've had a lot of success of getting people signed up. And as far as your percentages go, correct me if I'm wrong, you're going to have 91 percent of the royalty owners and --

A. That's right.

Q. -- 94 percent of the working interest. So that's -- Do we have more questions?

MS. MacQUESTEN: I don't think I have any.

EXAMINER JONES: Okay. Okay, thank you very much.

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

DAVID A. GODSEY,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. State your name for the record.
A. David A. Godsey.
Q. Where do you reside?
A. Edmond, Oklahoma.
Q. By whom are you employed?
A. Chesapeake Energy.
Q. And what is your current position with Chesapeake?
A. I'm a senior geologist.
Q. Have you previously testified before the New Mexico Oil Conservation Division?
A. Yes, I have.
Q. At the time of that testimony, were your credentials as an expert in petroleum geology accepted and made a matter of record?
A. Yes, they were.
Q. Are you familiar with the Applications filed in each of these cases?
A. Yes, I am.
Q. Have you made a geological study of the area that

is the subject of the Applications?

A. Yes, I have.

Q. And you've worked on the Chesapeake team, both geologists and geophysicists, who have prepared and recommended this portion of the case and project?

A. Yes, I have. I'd say all of this was prepared either under my direct work or supervision.

Q. Are you prepared to share the results of Chesapeake's work with the Oil Conservation Division?

A. Yes, I am.

MR. CARR: Are the witness's qualifications acceptable?

EXAMINER JONES: Qualifications are acceptable.

Q. (By Mr. Carr) Mr. Godsey, have you prepared exhibits for presentation in this case?

A. Yes, I have.

Q. Let's go to what has been marked Chesapeake Number 13, and I ask you to identify the exhibit, explain what it shows and tell us if this is the Wolfcamp or the Abo.

A. Okay. This is what I've, I guess, put together as a type log for the field. This is the Burrus Number 5. It's located in Section 27, Unit B, of 12 South, 38 East.

What you see here, on the left side of this exhibit is the neutron density log with a gamma-ray, microlog. On the right side is the core data, conventional core that was taken through this interval in that wellbore. And then below that you see a photo micrograph from thin section work that we did, as an example of what that rock looks like, porosity, permeability and pore geometry relationship.

Now, you see in pink there, designated as top of Burrus pay, that would be the -- what we would call the top of the pay or the top of the porosity in this interval. Highlighted in green and labeled gamma-ray hot streak marker, that's a hot gamma-ray marker we see in every well on the field, and you can actually see it for a very large area throughout the region.

At the base of that, labeled in black, is the top of the Wolfcamp limestone. The terminology here is confusing in that originally in the past, this interval had been designated as Wolfcamp and accepted by the OCD as Wolfcamp in other fields throughout the area. This zone produced to the southeast, about two and a half miles away, in the Bronco field, produces in other parts of Lea County, as well as on into Eddy County. Further to the west, the more recent stuff has been recognized as Abo.

And if you'll look at this, in reality, stratigraphically, this is the basal part of the Abo dolomite, is what it really is in reality, and the Wolfcamp is generally considered to start where the limestone facies begins below this.

I've discussed this with the OCD geologist in Hobbs, New Mexico. Because of the can of worms it would open, we have continued to call this Wolfcamp, because all the production books show this interval in this area to all be Wolfcamp. They recognize that it's probably truly Abo stratigraphically, but it's close enough, and it's been accepted for years and years as Wolfcamp. So we still call it Wolfcamp, but in reality it probably is the basal part of the Abo dolomite section.

Q. And that's the reason we define the unitized interval, or unitized formation, in the agreement as a common source of supply of oil and gas which is commonly known as the Wolfcamp formation but geologically known as the Abo dolomite formation; isn't that right?

A. That's correct.

Q. And that's how we have defined it in the unit agreement?

A. (Nods)

Q. Now, Mr. Godsey, this is a type log we're using for the hearing, the Burrus Number 5?

A. Yes.

Q. That is not the type log that is identified in the unit agreement?

A. That is correct.

Q. The type log that's in the unit agreement is the Limark Corporation State DZ Number 2 well?

A. That's correct.

Q. And that -- the log for that well is shown on our east-west cross-section, number two?

A. Actually it's on the north-south cross-section, number two. But yes, it is shown.

I used this as the type log for this hearing because we had the most data on it. This is the well -- the producing well in the field where we have the core data. I could lay it in here, depth correct it to the wireline logs, and you'd have the most information about that well in the field.

Q. Has the portion of the reservoir which you propose to unitize been reasonably defined by development?

A. Yes, it as.

Q. Can you generally describe the nature of the Wolfcamp/Abo formation in this area?

A. Yes, I can. We had this core analyzed not just with routine core analysis, but we took the core data, or core itself, to Sue Reed, a consultant in Midland, Texas, and there she did a detailed description of the core with binocular scopes. Then she went in and took thin sections through here and studied this core for us.

The conclusions that we draw from this is that this is a subtidal back-reef facies, which is fitting with where it sets relative to the Abo trend. This is some 27-odd miles backshelf from the Abo shelf margin, where you have so much of the more accepted Abo production. So this is way up on the shelf, it's at the basal part of the dolomitized section, and it's all pretty much -- relatively low to moderate energy, inner-shelf, subtidal deposition.

Q. Let's go to Chesapeake Exhibit 14, the composite map. Take that out and explain to Mr. Jones what this is and what it shows.

A. Okay, this is a composite map of the field area. The waterflood outline is shown here by the relatively thin purple line you see boxing the entire region in. There's a structure at a 10-foot contour interval shown. The structure is on top of the porosity. And then in green is the net porosity isopach.

Now, I've indicated on here, beside each wellbore, two numbers. The larger number in red would be the net porosity equal to or greater than 10-percent crossplot porosity. The smaller purple number would be the net porosity equal to or greater than six-percent porosity.

This map was generated by subsurface control, as well as 3-D seismic data that we have over this area. It also shows on here the four cross-sections that I've submitted as exhibits, and the type log for the Burrus Number 5 is indicated. And I believe we have scale and everything on here for you.

The isopach is a 10-foot contour interval.

Q. In picking unit boundary, you haven't done it the traditional way of working back from dry holes?

A. No, we have not. This is an instance that I think we'll see more and more in the industry, where the field has not and does not need to be defined by its dry holes. With the seismic data that we've had and the success we've had in delineating productivity with it, we can define clearly the limits of -- the productive limit of the field.

Now, the way we're doing that is, the -- it turns out that the porosity character gives us a distinct seismic amplitude anomaly. We have very carefully integrated the 3-D amplitude anomaly with the well control. We've come in here and picked this at various cutoff, 6-, 8- and 10-percent porosity cutoffs, and integrated that with the anomaly that we're seeing in the seismic data to clearly define where the porosity development is.

As we get outside the zero line on the isopach, the anomaly has totally disappeared, and there is no porosity development.

Now, within the outline of this waterflood unit, we have had 100-percent success in predicting porosity development. Now, I'm not saying we have 100-percent success at predicting exactly how many feet we would have, but we've gotten pretty darn close.

Now, the way we have done that is, we went a further step than just looking at the seismic amplitude anomaly and comparing it to the wellbore and iterating that back and forth. We did a Hampson-Russell seismic trace inversion, velocity inversion, and we had that done by Jasha Cultreri, a consulting geophysicist in Midland, under my supervision. I've worked with him on several projects like this over the years.

And what that actually is, it's like the reverse of making a synthetic seismogram. There, you know, you would take a sonic log and make a seismic trace out of it.

Well here, we're taking the seismic, which basically is acoustic data anyway, and we're making a sonic log out of it. Basically, we're looking at velocity.

Now, if you are very careful in integrating this with your well control so that you know clearly what your lithology is, then changes in velocity should be due to changes in porosity.

So in this case, as we saw in the first geologic exhibit here, we clearly know we're in a dolomite. We know that it's limestone below it, but the pay zone is very clearly dolomite. So that as we see changes in that velocity, we can directly attribute that to changes in porosity. And it has worked very good.

So with that type of control and that, you know, pretty much state-of-the-art technique, using seismic trace inversion, we can clearly define the limits of the field.

Q. Based on your work, are you convinced that the entire unitized area should contribute reserves to the unit?

A. Yes, I do.

Q. Let's go to Chesapeake Exhibit 15, east-west cross-section 2.

Well, just a minute, let's be sure we're right. I've got 15 as north-south 2. Which do we need to go to?

A. Actually, what's labeled as Exhibit 15 is north-south 2.

Q. Are you ready to go to that one?

A. I can go to that one.

Q. Okay, let's go to that one.

A. Sure, that way we stay in sequence.

This is a structural cross-section using the porosity log data that we have in the field. On the left end it starts on the north with the Burrus 23 Number 5, and on the right end it basically traverses through the -- say the eastern half of the field, through the Watkins Number

1, the last producing well in that area, down to an old Livermore Tyson Field Number 1 that was, I think, plugged and abandoned in the 1950s.

What you see in here -- as we saw on the type log, you see the top of the Burrus pay. You can see that -- in green, the hot streak gamma-ray marker there. And again, you can see the top-of-the-Wolfcamp limestone.

And then the well number three on the cross-section -- that would be the third one from the left -- is the Limark Corporation State DZ Number 2, which is the well that was designated in -- as the finding unit, you know, for the --

Q. It was the type log in the unit?

A. -- as the type log in the unit. Okay?

One thing I would note for the Examiner is that the well control here and the quality of the logs is excellent. We have -- for all the producing wells in here we have triple combos, most of them with a microlog. And with the exception of the two Limark wells, the DZ 1 and 2, I believe every one of them are Halliburton logs. We stay consistent with Halliburton to try and stay as consistent -- apples-to-apples comparison all the way through the field.

Q. Let's go to Exhibit 16, cross-section east-west 2.

A. Okay. Exhibit 16 is the east-west cross-section. It starts on the west end with the Burrus Number 7, our producer. Again, all these cross-sections are structural cross-sections. It shows the same horizons, the top of the Burrus pay, the gamma-ray hot streak that you can see, and the Wolfcamp limestone beneath that.

Well number two on the cross-section is the Burrus Number 5, which is the first exhibit I showed that contained the core data and everything on it.

Again you can see, it's a very easily correlatable zone. The porosity is relatively obvious. We've got good control on it, and it we're very comfortable with how well we tie in.

Q. All right. Now, before we go to the other cross-sections let's go to Exhibit 17, to the seismic trace inversion data.

A. Okay.

Q. This east-west line of section, the seismic line, it follows the same line as the cross-section, east-west 2, that you just presented; is that right?

A. Yes, it does. We extracted this out of the volume of the seismic trace inversion, and we extracted it to duplicate this cross-section so you could very clearly see what we're seeing seismically. It's not the actual seismic data itself, it's the velocity inversion. And we're presenting it in color so you can see this basically slow or fast velocity that we see here.

The wells are labeled on here as you see them on the cross-section. We've put some footages, both horizontal and vertical, so you get a feel for scale. The Burrus zone is identified in here. And if you look -- in -- kind of a -- outlined in black on the seismic line, you can see where the Burrus zone is occurring in the seismic section.

Now, the faster rock, or the very low-porosity rock, and the dolomite would be that more -- getting blue to dark blue to purple. As it gets slower or more porous, it gets into the greens and into the very light greens and almost white. And that is where we can take that data and get a very good feel for really how much porosity we actually see, rather than just looking at amplitude where you say, oh, it looks porous or it doesn't look porous. Here we get a feel for just how porous it may be.

Q. Is this the Hampson and Russell technique you were talking about earlier?

A. This is the Hampson-Russell technique, it's a model-driven technique developed by a group in Calgary, I believe. It's been used extensively by a lot of companies in the industry, and it's becoming more common all the time.

Q. And this is the way you went about defining the reservoir and picking the unit area?

A. Yes.

Q. Okay, we have two more cross-sections, Chesapeake Exhibits 18 and 19. They're north-south 1 and east-west 1. What do these show?

A. Really, they show the exact same thing, the exact same correlatability through the field. We can go through those. In the interest of time, if you want, you can just accept them as exhibits and look at them. But basically, they're laid out exactly the same as the previous two cross-sections, they show the exact same correlations through the field.

And by having all four of those cross-sections you've got not quite all the wells in the field, but almost, to look at.

Q. What geological conclusions can you reach from your study of the reservoir?

A. Well, several conclusions I can get to from this. First of all, it's a clearly definable field. We know -- if you look on the seismic data and if you look at the structure map, we know that the field is defined in the eastern limit by porosity loss, as well as going downdip and getting wet down in this deep low that we have on the east side of the field. The rest of the field is limited by the porosity loss, i.e., the loss of any type of porosity that would contain hydrocarbons up here, and that gives us our updip seal.

The data that we have on the core and the analysis we did to that gives me a very good feeling that this should be very floodable. One thing we did note in the core data, or in looking at the core, was, there was no moldic, you know, no occluded, vugular porosity. It was really -- and no fracturing to speak of, no open fractures at all.

The texture could be described as a finely sucrosic dolomite. It's a good, commonly used descriptive term in the industry, sucrosic giving the connotation of sugary-type texture. And that's exactly what it is.

With that type of texture, it almost makes it kind of sandy-like, as far as how it may perform. So basically, we have pretty good matrix porosity and permeability. In fact, when you look at the porosity and permeability plots, a $k\phi$ plot, you see a very good trend developed, better than a lot of carbonates.

You know, a lot of carbonates are very heterogeneous, and I'm on the record at Chesapeake as having called this a very homogeneous heterogeneous rock. Okay? Meaning we don't have big vugs and we don't have fractures in the thing. It's a very matrix-driven porosity-permeability relationship, so I think it should be a very good flood candidate, and I think the field is clearly defined with the data we have.

Q. Mr. Godsey, can the unit area, in your opinion, be efficiently and effectively operated under the proposed unit plan of development?

A. Yes, I believe it can.

Q. Were Exhibits 13 through 19 prepared by you or compiled under your direction?

A. Yes, they were.

MR. CARR: May it please the Examiner, at this time we'd move the admission into evidence of Chesapeake Exhibits 13 through 19.

EXAMINER JONES: Exhibits 13 through 19 will be admitted into evidence

MR. CARR: And that concludes my direct examination of Mr. Godsey.

EXAMINATION

BY EXAMINER JONES:

Q. I don't have many questions except maybe, do you have an analogy pool, waterflood, Abo --

A. Well --

Q. -- has similar type of rock?

A. Well yes, as a matter of fact, I'm trying to think of the name of the field. The Denton or North

Denton --

MR. BRADLEY: North Denton.

THE WITNESS: -- North Denton field is out of this same. I think the production books again show it as Wolfcamp. But it's the same dolomite sitting right at the base of the Abo, and it has been flooded.

Also, not really flooded, but nearer to us in the Bronco field, this zone produced also. And it wasn't really flooded, but there was some injection into the zone, and we thought we could see a little bit of response from that little bit of injection that they did there. So this is -- this has been flooded some. If you search for it under Abo you probably won't find it, because of the Wolfcamp semantics problem here.

Q. (By Examiner Jones) But it's not the same thing as the Vacuum Abo stuff?

A. No, that's --

Q. Totally different?

A. -- that's a very different beast, totally. I mean, the Vacuum Abo, that's at the terminus of the Abo reef shelf margin, and in no form or fashion would I call that a homogeneous heterogeneous rock. It's -- you'd have a lot more vugular-type porosity, collapsed structures and like that.

In looking at the core here, we do see it as a fairly homogeneous-type-looking rock. As a matter of fact, that hot gamma-ray streak that you see on all the wells in here is not a shale at all. That's just a mineralization zone that created high gamma-ray, there's not any shale in it. I was very surprised myself.

That's comforting, because I was concerned initially that we could have some shale barriers in here, and we did not see them in the core at all.

Q. The microlog sure shows this zone very well --

A. Uh-huh.

Q. -- especially the top of it.

A. Right.

EXAMINER JONES: Well, I can't think of any other questions right now.

THE WITNESS: Okay.

EXAMINER JONES: Thank you very much.

MR. CARR: At this time we would call Everett Bradley.

EVERETT BRADLEY,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Everett Bradley.

Q. Where do you reside?
A. Oklahoma City, Oklahoma.
Q. By whom are you employed?
A. Chesapeake Energy.
Q. And what is your position with Chesapeake Energy?
A. I'm a senior reservoir engineer.
Q. Mr. Bradley, have you previously testified before the New Mexico Oil Conservation Division?
A. No, I have not.
Q. Could you review your educational background and work experience?
A. I'm a graduate of the University of Tulsa, bachelor of science degree in petroleum engineering. I have worked throughout the industry with majors and large independents, Amoco Production Company, Williams Exploration, Mapco Exploration, Enserch, and now I'm with Chesapeake.
Q. And have you at all times worked as a petroleum engineer?
A. Yes, that's correct.
Q. Are you familiar with the applications filed in these consolidated cases?
A. Yes, sir.
Q. Have you made an engineering study of the area that is involved in this case?

A. Yes, I have.

MR. CARR: Are the witness's qualifications acceptable?

EXAMINER JONES: They are acceptable.

Q. (By Mr. Carr) Mr. Bradley, are you familiar with the New Mexico Statutory Unitization Act?

A. Yes, sir.

Q. And have you prepared exhibits for presentation in this case?

A. Yes, sir.

Q. Let's go to what has been marked for identification as Chesapeake Exhibit 20. Could you identify that and review it for Mr. Jones?

A. Yes, this map shows the boundaries of the proposed unit. That boundary contains 1720 acres. This also shows each of the wells that are within the proposed boundary. Each well is identified with its lease and its number, and there are 27 -- yes, 27 of these wells within the unit.

Q. This map actually shows current development in the unit area?

A. This is the -- shows the status of the current wells, the producing wells.

Q. Let's go to Exhibit 21. What does this show?

A. 21 is very similar to the first exhibit, but we've put triangles, light blue triangles, around the proposed conversions. This will be our initial conversions. There are seven of these wells, and they're around the peripheral of the heart of the unit.

Q. Why are you approaching it this way? What information will you gather by starting with this peripheral development?

A. We envision that to flood the entire interval with timely sweep and recovery, we'll have to have more than seven wells. But we know that there may be things out there that we're unaware of, permeability trends or barriers to fluid movements. We want to examine that and see whether or not we can determine that that's the case. And based on that knowledge, we would then design to flood the rest of this unit.

Q. Mr. Bradley, before we go on, I want to address a terminology matter. On the bottom of Exhibits 21 and 22 you talk about waterflood development in the unit area in Phase 1 and Phase 2.

A. We wanted to make it clear to the other working interest owners that we envision two stages of capital investment. Our interest is in the entire unit, not a portion of the unit. But the capital necessary to start the flood and do the initial seven wells, we call that Phase 1.

Then when we go forward with the rest of the capital in Phase 2, at least the bulk of the rest of the capital, we call that Phase 2, so they would understand we're going to be coming to them for additional capital.

Q. And when we use these terms, we're not talking about two geographic areas within the unit, we're talking about stages of development; is that correct?

A. That's correct, we think of it more as a point in time.

Q. If we look at Exhibit 20, that's the current development, and then we went to 21, which showed the first phase of the waterflood project with the peripheral flood, what is Exhibit 22?

A. Exhibit 22 is a possible expansion. It envisions drilling four producing wells, one additional injection well and converting two wells to injection. With that, we would have 24 producing wells and 10 injection wells.

And I -- you could envision this as a line -- alternating line of injectors, producers, injectors, producers. That capital would bring us up to about an additional $7 million -- or, I'm sorry, a total of about $7 million.

Q. Let's go to Chesapeake Exhibit 23, the production graph. Would you review the information on that exhibit for Mr. Jones?

A. This shows the oil, gas and water production history. The oil is in green. It shows that the field started production in January of '02 -- I'm sorry, that's '01. With drilling we reached a peak over a period of approximately -- reached a peak of about 70,000 barrels per month. There was additional drilling beyond that point. Nevertheless, the field did go on decline. It's declined down to a point of around 14,400 today.

There will be conversion of wells and continuing decline of the primary production until we see the initial responses. We envision we will see that, if we start injection 1-1 of '06, in late '06 or early '07, we'll arrest the decline, start to build a bank. As those banks hit our producing wells, we'll bring the well -- the field, to a secondary-recovery peak of around 39,000 barrels per month.

We'll hold that for a short period of time. The field will go on secondary decline and recovery our secondary reserves and the remainder of our primary reserves.

Q. Could you identify Chesapeake Exhibit 24 and review the information on that exhibit for the Examiner?

A. Yes, 24 shows the volumes of oil that we anticipate to recover under primary operations. If we did not put the secondary recovery in, we believe our ultimate primary would be 2.01 million barrels.

At the anticipated start of injection, which would be 6-1 of '06, the remaining primary is .48 million. Our secondary reserves are 1,720,000. At the start of our injection, our remaining reserve, both primary and secondary, we calculate to be 2.2 million.

If future prices are $49 per barrel, this represents a cash flow of $84,300,000.

Q. Mr. Bradley, if unitized management and further development of this unit area with the waterflood project are not undertaken, will the additional reserves that you have shown on Exhibit 24 be wasted?

A. That's correct the waterflood reserve would be wasted.

Q. What is the basis for the participation formula in the unit agreement?

A. We had five parameters for our unitization. Those were -- Those were the wellbores on each tract, was one of the factors. It was weighted 20 percent. All of our tract factors were weighted equally, 20 percent each.

Our second component was the average rate of production from our existing wells. We averaged that over January, February, March and April.

The third component was the primary reserve, and that reserve was calculated as of 5-1 of '05.

The fourth component was the estimated ultimate recovery from the existing wells on primary decline.

And our last component was the hydrocarbon pore volume under each tract.

Q. And why were these parameters selected?

A. The first one, the wellbores, are essential to the recovery of any of the hydrocarbons. So using the wellbores was a way to compensate the working interest owner for that capital investment that he's contributing to the unit.

The second one, the average rate, these wells are all producing and yielding income, current income, to the operator. This is a way of recognizing and compensating the working interest owner for the current rate that he's contributing to the unit.

The third is the primary reserve. This is independent of time. Not looking at the current rate, but what is left for him to recover that he's contributing to the unit.

The fourth one, the estimated ultimate recovery, independent of whether or not that tract has a well or wells, this recognizes -- I'm sorry, I'm confused with the last one. The estimated ultimate recovery recognizes the total production that that operator would have from his existing wells and that he is now contributing to the unit.

And the fourth one is the hydrocarbon pore volume, and it recognizes the hydrocarbons under that tract, whether or not it has a well, and the fact that those would be contributed to the unit.

Q. In your opinion, does the proposed formula allocate production to the separately owned tracts in the proposed unit on a fair, reasonable and equitable basis?

A. Yes, it does.

Q. Will unitization and the adoption of this proposed -- of the proposed unitized methods of operation benefit the working interest owners and the royalty interest owners in the area affected by the Application?

A. Yes, all will benefit.

Q. Let's go to Chesapeake Exhibit 25, the Form C-108. Does this form contain all the information required by the form?

A. Yes, it does.

Q. Is this an expansion of an existing project?

A. No, it isn't.

Q. And how many wells are included in this Application?

A. Seven wells.

Q. Does Chesapeake seek authority to commit additional wells to injection at orthodox and unorthodox locations through the Division's administrative procedures?

A. Yes, we do.

Q. Let's go to this exhibit, and I'd ask you to refer to one of the maps. There's one on page 12, and I've numbered the pages. What does this map show? Do you have a copy?

A. I don't have --

Q. It will make it easier if you did.

A. Okay. This shows one of the proposed injection wells. It shows a radius of a half a mile and a two-mile radius. Those are the wells that we have examined, particularly to protect fresh waters.

Q. And this shows generally the leasehold and the ownership in the area?

A. It does. Each tract has an ownership shown.

Q. And these are current as of what, June of this year or something like that?

A. June.

Q. You have a two-mile radius and the half-mile area of review, did you say that?

A. Those are -- That's correct.

Q. Does this exhibit contain all the information required by the Division for each well in the area of review which penetrates the injection interval?

A. Yes, it does.

Q. And that's contained on a number of well sheets and tables on pages 6 through 36 of the exhibit?

A. Yes, one for each of the wells.

Q. Are there plugged and abandoned wells within the area of review that penetrate the injection interval?

A. No, there aren't.

Q. Have you reviewed the data on available wells within the areas of review for this waterflood project and satisfied yourself there's no remedial work required on any of these wells to enable Chesapeake to safely operate this project?

A. That's correct, all of these wells are in good condition.

Q. In fact, most of the wells are Chesapeake wells, are they not?

A. Yes, most wells are.

Q. There were approximately how many that were listed that were not actually Chesapeake wells?

A. Within the half-mile radius --

Q. -- of an injection well.

A. -- of an injection well, I believe there were six wells.

Q. In fact, in preparing this, in reviewing the area for this Application, we went beyond just the half-mile area of review, did we not?

A. We went beyond the half-mile -- we went a half

mile from the unit boundary --
Q. And is that shown on --
A. -- which is in excess of a half mile from the injection well.
Q. And is that shown on Exhibit 11?
A. Yes, it is.
Q. I mean on page 11, I'm sorry.
A. Page 11 shows each of those wells.
Q. What injection volume does Chesapeake propose to inject in this project?
A. In the initial stages we anticipate 1000 barrels per well, or 7000 barrels for the project.
Q. Will this be by vacuum?
A. Initially we'll see very low or possibly no pressures at all, at the surface.
Q. And do you anticipate that you would be going over these initial volumes, 1000 per well, 7000 for the project area?
A. Depending on the number of wells we ultimately develop, we might go over the 7000. Of course, we'd come back for applications, but with the initial seven wells it would be really surprising if we go over the 7000.
Q. What is the source of the injection water you propose to use?
A. We will be re-injecting all of the water we've

produced from this unit, and initially that's a small volume. We'll have makeup water, which is produced water from the Devonian formation.

Q. The Application indicated that there might be fresh water used as makeup water; is that correct?

A. It is correct that that is shown on the Application, but that's an error. There won't be any fresh water used in this project.

Q. Is there an analysis in the exhibit of the Devonian water?

A. Yes, we included the water analysis of Devonian.

Q. And that is on page 39 of Exhibit 25.

Mr. Bradley, will this be an open or closed system?

A. It will be closed.

Q. And what injection pressure is Chesapeake proposing? I think we've discussed this, but --

A. Our maximum pressure is 2000 pounds, 1800 to 2000 pounds at the surface.

Q. There was another error in the Application, was there not?

A. That's correct.

Q. It stated 4600 pounds, and that is no what you're seeking?

A. That's correct.

Q. Will a surface injection pressure of .2 pound per foot of depth at the top of the injection interval be satisfactory for Chesapeake's purposes initially?

A. Yes, it will.

Q. And if higher pressures are needed, Chesapeake will justify the higher pressure with an OCD-monitored or -witnessed step-rate test?

A. Yes, we will.

Q. What is the current status of the wells that Chesapeake is proposing to utilize for injection?

A. Those wells are producing wells.

Q. And are they producing at various rates?

A. Various rates.

Q. How will Chesapeake monitor these wells to assure the integrity of the wellbores?

A. There will be a packer that isolates the annulus. There will be a packer fluid in that space, in that annular space. We'll put a pressure gauge so that we can monitor the back side and know if there's any pressure communication with that back side.

Q. By so doing, you will comply with the requirements of the federal underground injection control program?

A. Yes, we will.

Q. In your opinion, will the proposed injection in these wells pose a threat to any underground source of drinking water?

A. No, we won't.

Q. Are there freshwater zones in the area?

A. Yes, there are freshwater zones.

Q. And what is that formation? Do you know?

A. It's the Olagallah water [*sic*] -- I hope I have that pronunciation correct.

Q. Do you know the depth?

A. It runs from 35 feet to 125 feet.

Q. And you will, of course, not be injecting into these formations?

A. No, we will not be injecting there.

Q. Are there freshwater wells within a mile of any of the injection wells?

A. Yes, there are.

Q. And does page 38 of Exhibit 25 contain a water analysis from two of these freshwater wells?

A. It does.

Q. And all wells are cased and completed in the project area so as to avoid or prevent any problem with the water wells in the area?

A. That's correct.

Q. In your opinion, will injection of water -- Well, we've asked this.

Have you examined the available geologic and engineering data on this reservoir?

A. Yes, I have.

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

A. There are no connections between the Abo and the freshwater zones.

Q. I'd like to now talk about the Enhanced Oil Recovery Act and qualifying this project under that act. Would you identify Chesapeake Exhibit 26?

A. This is our Application for this enhanced recovery project to benefit from the -- New Mexico's Enhanced Oil Recovery Act.

Q. Does this Application meet the requirements of the OCD Rules?

A. Yes, it does.

Q. And it is a complete application?

A. Yes, it is.

Q. What are the estimated additional capital costs to be incurred in this project?

A. The total capital for the project, both phases, is about $7 million.

Q. And what are the total project costs?

A. If we include life of the project, direct operating costs, overhead, workover, remedial work, royalties, overriding royalties and taxes, those expenses could come to $50 million.

Q. How much additional production does Chesapeake expect to obtain from the project?

A. We expect in excess of 1.7 million barrels.

Q. Are you going to have any significant amounts of hydrocarbon gas?

A. No, we won't.

Q. And what is the total value of this additional production?

A. The cash flow from this at $49 a barrel would be in excess of $84 million.

Q. Now this exhibit contains the -- a production graph as required by the rules?

A. Yes, it does.

Q. That is actually the same production graph that you have previously reviewed, that's marked Chesapeake Exhibit Number 23?

A. Yes, sir, it's the same exhibit.

Q. And does this Application also contain the other exhibits required by the rules of the Oil Conservation Division?

A. Yes, sir, we have outline of the unit, Exhibit A;

a list of the wells, Exhibit B; and a cross-section, Exhibit C.

Q. Is unitization as proposed reasonably necessary to effectively carry on secondary recovery operations?

A. Yes, it is.

Q. Do you believe that utilization of these methods -- do you believe they will prevent the waste of oil and protect correlative rights?

A. Yes, sir.

Q. Will approval of the Application otherwise be in the best interest of conservation?

A. Yes, it will.

Q. Were Exhibits 20 through 26 prepared by you or compiled at your direction?

A. Yes, they were.

MR. CARR: I move the admission of Chesapeake Exhibits 20 through 26.

EXAMINER JONES: Chesapeake Exhibits 20 through 26 will be admitted into evidence.

MR. CARR: And that concludes my direct examination of Mr. Bradley.

EXAMINATION

BY EXAMINER JONES:

Q. Mr. Bradley, the tract participation parameters --

A. Yes, sir.

Q. -- those are for cost and revenue; is that right?

A. That is correct.

Q. Okay, and there's only going to be one -- each tract is going to get one parameter, and that's going to be it, for the whole --

A. Each tract has one participation factor, and those together make up 100 percent of the unit.

Q. Okay, so it doesn't -- It's going to be the same, no matter if you change your configuration of injection wells, add more injection wells?

A. These tract factors will stay the same.

Q. Okay. And Chesapeake -- you're convinced that the tract factors are fair and equitable for all tracts?

A. They are in my opinion. Every working interest owner has received a copy and has reviewed this, and over 90 percent of them have voiced positive affirmation. No one has -- they've -- either positive or no reply.

Q. Okay. As far as the C-108 goes, the Devonian-Abo waters, are they compatible?

A. They are compatible. We have done a sample of those, we've mixed those, and we've performed a water analysis, and we've included that in this packet.

Q. Okay. And your predicted secondary response is not quite as high as your primary response?

A. No, we don't believe it will. We're not fully depleted, but many of these wells are substantially depleted. We won't be putting all of our injection on at the same time. Some areas will see pressures earlier than other areas, so we don't believe we'll catch that peak that we initially got, particularly since these wells were drilled in rapid succession.

Q. In your opinion, what would have been the ideal time to start waterflood operations in this reservoir?

A. I believe you should start as early as possible, while you have as much of the reservoir's native pressure to work with. So I would have desired to start a little earlier.

Q. Okay. You guys have covered an awful lot of stuff here. The likelihood is, I might have forgotten to ask some questions, but I think you covered it all really well, so I think we're okay.

A. Thank you very much.

MR. CARR: Mr. Examiner, at the end I would remind you that we did receive a protest in this case. As of two weeks ago we thought we had resolved the issue, and it surprised us last week actually when the protest was filed.

We did talk to the other side, and it was surprisingly easy to resolve it, because the parties were not in disagreement, it was just the language that didn't reflect the intent of the parties. But to resolve this, we agreed to request that the order reflect that Exhibit G to paragraph 3 be amended. That is our Exhibit 5, and I would request that that be included in the order.

And we also intend to re-ratify but only have working interest owners re-ratify, because this is only in the operating agreement. It has no bearing -- It's not a contract that involves the royalty interest owners. To require additional ratification by royalty interest owners would be a tremendous and, I really believe, unnecessary endeavor, and we are trying to get this waterflood project going hopefully, the first of the year, because we think the time is actually passing when it can be most effectively implemented.

And so for that reason, if there is anything in the order about re-ratification, we really request that it be limited only to the working interest owners, because they are the only people who could possibly be affected by and adjustment of less than one half of one percent of the working interest share.

EXAMINER JONES: Okay, we can address it in the order itself --

MR. CARR: Yes.

EXAMINER JONES: -- the -- With that, thank you very much, Mr. Bradley.

THE WITNESS: Thank you.

EXAMINER JONES: And we'll take Cases 13,582 and 13,583 under advisement.

MR. CARR: Thank you very much.

EXAMINER JONES: Thank you all.

(Thereupon, these proceedings were concluded at 1:50 p.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 29th, 2005.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2006