STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

CASE 10,653

EXAMINER HEARING

IN THE MATTER OF:

Application of Armstrong Energy Corporation for special pool rules, Lea County, New Mexico

TRANSCRIPT OF PROCEEDINGS



BEFORE: DAVID R. CATANACH, EXAMINER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

January 7, 1993

A P P E A R A N C E S

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# E X H I B I T S

APPLICANT'S EXHIBITS:



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WHEREUPON, the following proceedings were had at 11:12 a.m.:

EXAMINER CATANACH: At this time we'll call Case 10,653. Application of Armstrong Energy Corporation for special pool rules, Lea County, New Mexico.

Are there appearances in this case?

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe law firm Campbell, Carr, Berge & Sheridan.

We represent Armstrong Energy Corporation, and I have two witnesses.

EXAMINER CATANACH: Any other appearances?

Will the two witnesses please stand to be sworn in?

(Thereupon, the witnesses were sworn.)

ROBERT M. BOLING,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Robert Michael Boling.

Q. Where do you reside?

A. Roswell.

Q. By whom are you employed and in what capacity?

A. I'm an independent petroleum geologist, retained by Armstrong Energy to testify before the Commission in this case.

A. As part of your employment with Armstrong Energy Corporation, have you made a geological study of the area which is the subject of this Application?

A. I have.

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

A. I have.

Q. At the time of that testimony, were your credentials as a petroleum geologist accepted and made a matter of record?

A. They were.

Q. Are you familiar with the Application in this case which has been filed on behalf of Armstrong Energy Corporation?

A. I am.

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

EXAMINER CATANACH: Yes, they are.

Q. (By Mr. Carr) Mr. Boling, would you briefly state what Armstrong seeks in this case?

A. We seek to promulgate special rules for the Northeast Lea-Delaware field.

More specifically, we seek to increase the allowable from 107 barrels a day to 300 barrels a day.

Q. Initially I'd like you to go out of order, refer to what has been marked as Armstrong Exhibit Number 5.

Would you identify this and review what this shows for Mr. Catanach?

A. I will. Exhibit Number 5 shows in stipple the 480-acre Northeast Lea-Delaware field, which was formed in 1986.

There are three operators presently operating in the unit: Pennzoil in the southeast southeast of Section 35, Township 19 South, 34 East, with their Mescalero Ridge Unit Number 3 well; Harken Exploration in the northwest of the southeast of Section 2, 20-34, their Mobile State Number 1 well; and Armstrong Energy in the northeast of the southwest of Section 2, 20-34, in the Mobil Lea State Number 1.

Q. These are the only current operators or current wells in the pool at this time?

A. That is correct.

The exhibit also shows all the Delaware wells within a mile of the subject well, the Armstrong well.

The Northeast Lea field is subject to statewide rules, 107 barrels a day allowable, 2000-to-1 gas/oil ratio, which gives an allowable of 214,000 cubic feet a day.

Q. Are you going to review the geological characteristics of this pool, and then we will have another witness to discuss engineering aspects?

A. Yes, I am.

Q. Let's go to what has been marked as Armstrong Exhibit Number 1. I'd ask you to first identify that and then review the information on this exhibit for Mr. Catanach.

A. Okay. Exhibit Number 1 is a stratigraphic cross-section that runs from the northeast on the right, the southwest on the left --

EXAMINER CATANACH: Hang on a second.

THE WITNESS: Okay. You need some help?

EXAMINER CATANACH: Got it.

THE WITNESS: Okay. Northeast on the right, southwest on the left, includes all the wells that are currently producing in the Northeast Lea field and all wells that have the subject reservoir productive in them, plus two wells that show the terminus of the stratigraphic limits of the producing interval in our subject well.

To begin with, on the right is the Pennzoil Mescalero Ridge Unit Number 3 well. This was the discovery well that initiated the Northeast Lea field.

It is -- Let me state that there are four sand intervals that I have correlated on this cross-section. I correlated the bases of all these intervals, and I'll refer to them as the first sand, second sand, third sand -- which is the producing interval in our well -- and the fourth sand.

I might state for the record that within the general area of this cross-section, every one of those sands is a productive reservoir, or appears to be. There are shows or production established in every one of these sands that lie immediately on top of each other.

Back to the Mescalero Ridge Unit Number 3 well.

As you can see, the perforations are from 5780 to 5805, which is in a carbonate interval but is equivalent stratigraphically to where the second sand would be. The second sand has -- We've reached the point of no deposition of the second sand, but the porosity is present in the carbonate, which is limestone here.

This well was completed in 1986 for initial production flowing of 64 barrels a day. It's produced about 24,000 barrels and is currently producing about five barrels a day.

Interesting, two other things to note on the Pennzoil well is that you can see the base of the first sand, which is the first correlation mark up there, there's a remnant of the first sand present, but tight. So we're beyond the productive limits of the reservoir in the first sand at that point.

If you go down to the third, the datum base of the producing interval, you'll see that the only thing left of that third sand interval is the gamma-ray indication of more radioactivity. But there's no porosity to speak of in that sand. It's tight sand. That is the northeast stratigraphic limit of the reservoir, the productive reservoir.

You will see below that the fourth sand interval is also tight, but present.

So this is my control, my trapping mechanism for the overall accumulation that we're going to talk about that covers two and a half sections out here on the northeast updip side.

The second well from the right is the Armstrong Energy Corporation West Pearl State Number 1, which is in the northeast northeast of 2.

This well is currently producing out of the Bone Spring at a rate of about 12 barrels a day. It is this week being plugged back, and a completion attempt will be made in the third sand interval in this well, which falls at approximately 5900 feet.

You can see that from one location to the next -- We've moved one location. We have now a sand that's got 24 feet of porosity greater than 15 percent. It's got shows of gas and oil. We have good fluorescence, we have a zone that we anticipate will be productive in this wellbore.

The stippled line, by the way, that is crossing this cross-section is the oil/water contact that we've determined for the producing interval through both observation and calculation, and I'll talk -- As I get to the wells where we encountered the interval, I'll talk about how we got that oil/water contact established.

But as you can see, the zone in the Armstrong Energy Corporation West Pearl State 1 well clearly lies above the oil/water contact, which is a minus 2269.

The third well is the Harken Energy Corporation Mobil State Number 1.

It's completed from 5626 to 5695. It was completed in 1988 for initial production of 112 barrels a day. Its cumulative production is about 68,000 barrels. It's currently making about 17 barrels a day, and some water.

Interestingly enough, you see again, you move one location from the -- two locations from the Armstrong well over to the Harken well, you see the first sand goes from a remnant with no porosity, effective porosity, in the Armstrong well, to a zone that's 66 feet thick with porosity greater than 15 percent.

And the second interval develops also. Again in the Armstrong well to the northeast, only a remnant of porosity, zero porosity. We come -- The sand is now 86 feet thick, two locations away.

The producing interval in this well -- The third sand, which is our producing interval, is marked there. And as you can see, it lies just below the oil/water contact, within a foot or two of the oil/water contact. We anticipate that this zone is wet. There's 18 feet of porosity greater than 15 percent in that well.

As we move over to the subject well, the Armstrong Energy Corporation Mobil Lea State Number 1, you'll see that the first sand has thinned in terms of net porosity isopach from 66 feet to about ten. This is one location west.

The second zone has increased. It's 110 feet thick, porosity, we had shows all through -- We had shows in the ten feet in the first zone, we had shows all through this 110-feet interval.

The subject interval, our productive interval, has gone from 18 feet thick one location away in the Harken to 86 feet thick with 60 productive feet of reservoir in the well.

And the fourth interval has thickened slightly and is wet in the Armstrong Energy Corporation well.

The fifth well there is the Spectrum 7 Mobile State Number 2 well, dry hole, in the southeast southwest of Section 2.

You see that the first sand thickened back up. There's 20 feet of porosity greater than 15 percent in that well.

We have approximately the same amount of second sand.

The third sand interval, 76 feet thick, so we lost a little sand.

And the fourth is approximately the same.

Now, when we were drilling the Mobil Lea

State Number 1 well, we drilled into this third sand, the productive interval, and lost shows. We drilled 60 feet of shows, and lost shows just like that. And when we calculated that point at which we lost the shows, it came out to a minus 2269. So at that time that was my initial indication that that may be the oil/water contact.

When I went in to remap this area after the well was drilled and looked at this Spectrum 7 Number 2 well, I noticed that the upper 20 feet of that reservoir exhibited similar resistivity and porosity characteristics as our well did. And in fact, there was a transition zone in that well. And when I went back and calculated the point at which it became 60-percent water saturated, which we think is effectively not productive, that came out to minus 2268.

So it looks to me like there's 20 feet of productive reservoir in that well that was never tested for some reason. I don't know what happened. But we have two indications there that the oil/water contact is at minus 2269.

The next well is the Read & Stevens North Lea Federal Number 7 well, which was drilled in the southwest of the northeast of Section 10.

As you can see, the second zone is quite thick. This well had shows in the first interval, which is not shown entirely on this cross-section up there. Above 5700 they had a show in this thick sand, in the second zone. And then in the third interval they perforated from 5942 to 5962. They pumped two weeks on that and pumped a hundred percent water.

You'll see that the top of that interval falls at a minus 2289, another indication that the oil/water contact is above minus 2289 someplace, indicating that the minus 2269 is somewhere near where the oil/water contact is.

I might just say that in our well, the Armstrong Energy Corporation Mobile Lea State, when we produced that well, the first five days that well made 1406 barrels. It made 564 barrels the first day.

The next well is Read & Stevens North Lea Federal Number 6. It's in the northwest northeast of Section 10.

Again, first zone is very thick. It's not all on this cross-section. Show in that zone.

Anemic show in the second zone, about the same thickness.

Their third zone, the top was encountered at 5890. They perforated 5900 to 5920, IP'd that well at 117 barrels a day. When we looked at the resistivity log and porosity log on this well and calculated the water saturation, we could actually see the transition zone about 15 feet thick in this well. And we calculated that that point at which we achieved the 60-percent water saturation or nonproductivity was again minus 2269, another indication that that is the oil/water contact.

The last well is the North Lea Federal Number 5, which is in the northeast of the northwest of 10, one location west of the Number 6.

And you'll see that the productive interval is completely gone. This is the stratigraphic limit on the southwest side of the reservoir.

Q. (By Mr. Carr) Mr. Boling, would you now go to what has been marked Armstrong Exhibit Number 2, your structure map on the base of the productive interval, and review the major structural characteristics of the Delaware in this area?

A. Okay, Number 2 is -- As Mr. Carr stated, this is a structure map on the base of the productive interval across this five-section area.

The two -- There are two features that are significant on this map.

The first is, you see a depositional low spot or a low spot running from the northeast up in 35 down across to -- and snaking across the northwest quarter of 11 and dumping into the depositional low, which is in the southeast quarter of 10 and southwest quarter of 11.

There's a minor depositional low coming down across the southeast -- southwest quarter of 3 and crossing Section 10, terminating in the same depositional low in the southwest quarter of 10 and southwest quarter of 11. These are the migratory pathways that the sands are going to follow when they become deposited.

The other thing to note is that updip, at least in Section 2, is just to the northwest. And you see that updip in Section 3 is to the northeast. This is indicating a strong nosing feature in Section 3 and 2. And in fact, this is along a high trend that runs for about three or four townships northwest/southeast and has Devonian production established at depth and several -- Bone Spring production to the north of us on structures.

So that structural feature is well documented in several geologic horizons and is expressed here as a long, large northwest-southeast trending nose.

The other important feature to note is down in Section 11, approximately in the east half of 11, in the east half, west half, there is another small high. What this has done, between the flank of the nose in Section 2 and the small high in 11 you have the depositional -- you have barriers to deposition.

So as the sand starts pouring down this low spot up in 35 and comes down into 2, it hits the barrier in 11 and the updip barrier in 2, and it acts as a funnel to funnel the sand right into these low spots that we see in the southeast quarter of 2 and down into 10.

And to a minor, lesser degree, the same thing is going to happen over in Section 3 and 10, in this depositional low that crosses 10. The effect is not as dramatic. So what we would expect is that we would get thicker sand accumulations over in 2 and 35 -- or in 2 than in 10, but the sand should be present.

Q. All right. Let's go now to your next structure map, Exhibit Number 3.

A. Yes. The next structure map is a map made on the top of the productive interval, and this map was -- The blue indicates our approximate oil/water contact, minus 2269.

We had to make a map on the top, because if we had put the oil/water contact on the base, it would have appeared that our well was wet, because the base is below the oil/water contact, but most of the reservoir is above it. So we had to make one on the top to give you a clear indication of where the oil/water contact is relative to the subject wells.

This map would indicate that the southwest quarter of 2, possibly the south half of the northwest quarter of 2, portions of the northeast quarter of 2, the north half of the northeast of 10 and the south half of the southeast of 3, are all going to be productive in this reservoir. They all occur -- portions of that sand reservoir occur above minus 2269.

Q. All right. Let's go to the net porosity isopach, Exhibit 4.

A. The net porosity isopach map, Exhibit 4, basically shows the effective productive area of the sand based on porosity. And what we see here is what we expect to see.

There in Section 2, in the southwest quarter, the depositional thick, 90 feet of porosity, just where you would expect to find it, wedged between the high in 11 that acts as a barrier to deposition and the flank of the nose in 2 and 3 that act as barriers to deposition.

That's where the thick is going to be, that's where it occurs, and it comes on down to the lowest depositional point out here, which is the southeast quarter of 10 and southwest quarter of 11.

If you use this map plus the base map, you can determine at which point you've lost your reservoir, and you're not going to have any more productive locations.

These two maps are the ones that indicate the production in the areas that I previously mentioned, in 3, 10 and 2.

Q. Mr. Boling, what conclusions have you been able to reach about this portion of the Delaware from your geologic study?

A. Well, there's several conclusions.

This is a -- These four sand intervals are separate reservoirs. They're not vertically connected.

We know that because we have oil in reservoirs that have water above them and oil above that, so we don't -- And that's exhibited in -- most specifically, in the North Lea Number 6 well where that's very evident. And in fact, they had oil in the third zone, water in the second zone, oil in the first zone, and there's another zone before that that's got oil in it, that's not present over in Section 2.

These are all separate reservoirs, and they all -- There's not a well out here, with the exception of the Pennzoil well, that has not been completed with the capability of producing more than the top allowable depth bracket at this point, 107 barrels a day.

Read & Stevens has wells that they've maintained 100 barrels a day consistently because that's the allowable, but they have other reservoirs that could be exploited if the allowable were higher.

In our case, I know that what's going to happen is, when we drill the next well we're going to move updip from this well. And when we do that, if the reservoir capacity to deliver, the productive capacity, is the same, is dynamic, and it's the same updip as it is in this well and it's linear, we're going to move updip and we're going to have 40 feet of reservoir left.

We have 60 feet of reservoir in this well that's capable of making 350 or 400 barrels a day. We go updip, we're going to have 40 feet of reservoir. If the dynamic of the reservoir is linear, that well is going to make 250 to 300 barrels a day. But the fourth interval that's wet in our well will be updip. It will be productive, and we'll test it first.

So we have a sort of unique situation here. We have four extremely high quality reservoirs in terms of lithology and deliverability capacity that all can be exploited, and in some cases we're going to have three of those quality reservoirs that are productive in the same wellbore.

Q. Will Armstrong also call an engineering witness to discuss the efficiencies or inefficiencies of producing these multiple zones under one allowable?

A. Yes, we will.

Q. Were Exhibits 1 through 4 prepared by you?

A. Yes, they were.

MR. CARR: Mr. Catanach, at this time I would move the admission of Armstrong Energy Corporation Exhibits 1 through 4.

EXAMINER CATANACH: Exhibits 1 through 4 will be admitted as evidence.

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

(Off the record)

EXAMINATION

BY EXAMINER CATANACH:

Q. Your Exhibit Number 4, is that just the net sand in the third --

A. Yes.

Q. -- in the producing interval?

A. Correct.

Q. Okay. Would you expect that Spectrum Mobil

State Well Number 2 to be productive in that zone?
A. Yes, I do.
Q. Do you anticipate that any of the remaining intervals will be as prolific as that third sand?
A. Well, that's -- The second sand is the only one that has not been tested in the area, production tested, even though we have shows.
It's kind of an enigma because it's quite thick in our well, we had shows all through it. It's quite thick in Read & Stevens' Well Number 6, northwest, northeast of 10. It's actually 20 feet higher, the top is, in their well, and their shows were different from ours.
Mud logs are not quantitative, but I would expect that at some point where we can encounter production into the second sand, it will be as prolific, yes.
With the exception -- With this one overriding exception: The grain size in the second sand versus the third sand is dramatically finer. When we look at these rocks in microscopic samples in the cuttings, there are two characteristics here that are unique.
They're very clean sands, which is unusual for the Delaware. We're very close to the source.

And the grain size differentiation between the second sand and the third sand is dramatic. The third sand is big grain size for the Delaware, and I think that's one of the reasons we have such deliverability in that sand.

But the second sand has a lot more vertical thickness over the area. So even though it's finer grain, the deliverability may be restricted because -- the permeability may be less, because the grain size -- we have a lot more H, and it's going to be -- Someplace, it's going to be a hell of a reservoir too.

And we know the first sand -- I don't know. Read & Stevens has completed four wells in that first sand, and I know that they've had wells that -- What's your best conclusion? 147 barrels a day?

So prolific reservoirs, yes.

Q. Okay. Would you expect all four reservoirs to be productive within about the same horizontal interval, I mean the same geographic interval?

A. Yeah, I've mapped all these sands individually across nine sections, and the third and fourth sands are going to be restricted to this area of the east half of 10 and 2.

They're not present in the west half of 10 or in 3 or around the corner in Section 9 or 4.

So this is the limit of the third and the fourth sand, right here.

The second sand, much greater lateral distribution. It goes around in 10 and up into 3, and it's thicker over there, it's consistently thick over there.

And the first sand is in fact much more widespread. It actually goes on up north of here, up into Section 33, up into the township to the north.

The productive portions of those reservoirs appear to lie -- of all those reservoirs -- appear to lie in these Sections 2, 3 and 10.

EXAMINER CATANACH: That's all I have.

MR. CARR: At this time we would call Mr. Stubbs.

<u>BRUCE STUBBS</u>,

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. Bruce A. Stubbs.

Q. And where do you reside?

A. I live in Roswell, New Mexico.

Q. By whom are you employed and in what capacity?

A. I'm a consulting petroleum engineer. I've been retained by Armstrong Energy to review the Northeast Lea-Delaware.

Q. And you've made an engineering study of the area?

A. Yes, I have.

Q. And you've prepared certain exhibits for presentation here today?

A. Yes, I have.

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 a petroleum engineer accepted and made a matter of record?

A. They were accepted.

Q. Are you familiar with the Application filed in this case on behalf of Armstrong Energy Corporation?

A. Yes, I am.

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

EXAMINER CATANACH: They are.

Q. (By Mr. Carr) Mr. Stubbs, let's go to

Exhibit Number 5 that Mr. Boling referenced in his testimony. Again, I'd like you to identify that and then in a little more detail review for Mr. Catanach what it shows.

A. Exhibit 5 is a one-mile radius around the Armstrong Energy well. It shows all the Delaware producing wells in that one-mile radius.

It also shows in the shaded area, the 480 acres that are attributed to the Northeast Lea-Delaware field.

Q. Are there any additional Delaware wells east of the acreage that is shown on this plat but within a mile of the pool?

A. No, we did a -- We pulled the records on all the wells, all producing wells in the nine sections surrounding that well, and they're in the pages attached to that first page, and there are no Delaware wells to the east of Section 2.

Q. What are the attachments to the initial plat in Exhibit Number 5?

A. Those are the listings of all the penetrations or all the producing wells in the nine sections surrounding the Armstrong Energy well.

Q. And those wells are indicated by a dark arrow?

A. Yeah, the Delaware wells are highlighted by a dark arrow.

Q. Let's move now to what has been marked as Armstrong Exhibit Number 6. Would you identify and review this, please?

A. Number 6 is a Delaware well summary, just so everybody can keep straight which zones we're talking about.

The first well is the Armstrong Energy Mobil Lea State well, producing out of the third sand at over 100 barrels per day.

The second well is the Mescalero Ridge up in Section 35. As Mr. Boling stated, it's producing out of a limestone. It's produced 23,000, almost 24,000 barrels to date and is presently producing about five and a half barrels per day. And that interval is equivalent to what we're calling the second sand.

Next well is the Mobil State, which is -- Mobil State Number 1, which is the Harken well. It's the east offset to the Armstrong Energy well. This is a first sand completion. It's cum'd about 70,000 barrels. They tested the third sand, and it was wet in that particular wellbore.

The next well, the Mobil State Number 2, is the south offset to the Armstrong Energy well. It tested the first sand, and it was found to be wet. And as Mr. Boling stated, the third sand, which is the equivalent sand the Armstrong Energy well is completed in, appears to have about 20 percent -- or 20 feet of porosity that should be productive. And I'm kind of at a loss why they didn't test it.

The next three wells, the North Lea Federal 1-Y, Number 2, and Number 3, are Morrow gas wells. I've looked at those logs, and what we find on those logs confirms what Mr. Boling has discussed as far as the oil/water contact. All three of those wells -- or two of those wells are -- the third sand falls below the oil/water contact. The North Lea Federal Number 2, which is the far west well, have a facies change, and the third sand disappears and turns to a lime.

The North Lea Federal Number 4 is a first sand completion. It's presently producing about 85 barrels a day.

And Number 5 is a -- has been completed in three different intervals. The fourth sand was 6000 feet. The third sand equivalent, which is a lime in that particular well, and then the first sand. And that well is capable of making over a hundred barrels a day.

The fourth sand produced about 72 barrels a day. The middle zone, the lime zone, produced over 50 barrels a day. And the first sand is producing over 107 barrels a day.

One comment on Number 5, and we'll discuss it a little bit more later, has had two casing leaks in the Seven Rivers Reef interval, and that gives us all some concern in this whole area.

North Lea Federal Number 6 is completed in the third sand, which is the same sand that the Armstrong Energy Well is completed in, and is also capable of producing over 107 barrels a day.

And as Mr. Boling discussed, the North Lea Federal Number 7 tested the third sand, but it's below the oil/water contact.

Next two wells, the Mark Federal Number 1 and Number 2, are on the west side of Section 3. They're first-sand completions, and both of those wells are capable of over 100-barrels-a-day production.

The last two wells are two kind of insignificant Delaware wells that kind of give you the boundaries on the south and to the west.

The Powell Federal Number 1 is in Section 4, which is west of the Read & Stevens wells, and it's a pretty poor well, making about nine barrels a day, eight barrels of water.

Union Federal A Number 2 is in the southwest of Section 10, making nine barrels a day and 75 barrels of water.

Q. And this exhibit basically confirms that we're dealing with multiple pay zones in this portion?

A. Yeah, there's at least four pay zones in this area.

Q. All right. Let's go to your production curves, Exhibit Number 7, and I'd ask you to review these for Mr. Catanach.

A. These are the decline curves for the wells in the Northeast Lea-Delaware field.

The first curve is just a summary, and -- of the two wells, the Pennzoil well and the Harken well -- and they've cum'd to date 93,583 barrels.

Then there's two separate curves for -- or one separate curve for each well, plus the daily production or monthly production figures.

The first one is the Pennzoil well up in Section 35, producing out of that carbonate equivalent to the second sand, and it started producing about 30 barrels a day and has since declined down to about five and a half or six barrels a day.

Q. How do these wells actually compare to the Armstrong well?

A. They -- Productivity-wise, they're not even in the same class. They more or less describe or determine the edge of the reservoir, in my opinion.

Q. Let's now go to the Mobil Lea State Number 1 well, your Exhibit Number 8, and I'd ask you to review that information for Mr. Catanach.

A. Okay, the Mobil Lea State Number 1 was frac'd and put on production October 28th, and this is a daily production test from that well.

As you can see, the first week or two they didn't know exactly what they had, and the first few days it made over 500 barrels a day. And they kind of got it under control and it leveled out, and then requested an exception from the OCD to produce it at twice allowable, and that's what they were shooting for at around 200 barrels a day. We had one period from about the 10th of December to a little after the 15th that we tested it at 275, 300 barrels a day.

What we were looking for during these tests was any indication that we were bleeding off excess reservoir energy or influencing water-coning or anything like that.

And now the next curve is the oil- and water-cut percentages. As you can see, the oil cut has been around 89 percent, and the water cut's been about 11 percent, and no real changes during any of the tests that we performed.

Third curve is the gas/oil ratio, and the gas/oil ratio has pretty well leveled out at 300 standard cubic feet per barrel.

Q. Basically, what this shows is, pulling the well at this rate you're not increasing the water cut?

A. We're not increasing the water cut, and it doesn't appear like the gas/oil ratio is increasing either.

Q. And what does this tell you about the possibility for causing reservoir damage by producing the well at the higher rate?

A. It looks like the well is capable of high-rate production without damage to your reservoir.

Q. Let's move to Exhibit Number 9. Could you identify this and then briefly review what it shows?

A. This is a calculation I did to derive a productivity index for this particular reservoir.

On December 17th, we ran a production test of 283 barrels a day, water production of 36 barrels, fluid level was at 48 joints, and casing pressure was 220 pounds.

The casing on this well has been shut in. We're not closing flowing gas off the casing, so it's remained static.

Also, I might mention that on January 1st we shot another fluid level, and it was still at 48 joints. So that means the fluid level in the annulus is about 1488 feet.

To calculate a flowing bottomhole pressure I used 38-degree gravity API oil gradient of .38 p.s.i. per foot to the middle of the zone at 5905, gives me a hydrostatic pressure of 1722 plus the casing pressure of 220, gives us a flowing bottomhole pressure of 1942 pounds.

Calculated a static bottomhole pressure from a drill stem test that was run on the North Lea Federal Number 3, and also compared it to a drill stem test that was run in this zone in the Harken well. It appears that the bottomhole pressure gradient is about .43 p.s.i. per foot, which yields a bottomhole pressure of about 2539.

So we're running -- We're producing 283 barrels of oil and 36 barrels of water with a pressure drop from 2539 to 1942, yields .53 barrels of fluid per p.s.i.

If we're able to pump this well off and maintain just 100 p.s.i. pump intake pressure, the well is capable of producing over 1300 barrels of fluid a day, being about 1156 barrels of oil and 147 barrels of water.

So at a production rate of 300 barrels a day, we're just barely lowering the bottomhole pressure by about 24 percent. We're not pulling the well very hard at all at that point.

Q. Let's go now to Exhibit Number 10. Would you identify the graphs that together comprise Exhibit Number 10?

A. Okay, Exhibit Number 10 is production decline curves for the Read & Stevens wells, the Powell wells -- or the Powell Federal well and the Union Federal well, and then the last about five or six curves are just some good Delaware wells located in Lea County.

And what I want to show in this is that the wells are capable, the Mark Federal wells are capable of producing over 100 barrels a day.

The first one is Mark Federal Number 1, and it's over 3000 barrels a month.

Mark Federal Number 2 has produced over 3000 barrels a month.

North Lea Federal Number 4 is now producing over 3000 barrels a month. It had a pump change. That dip is a pump change that was made on that particular well.

The North Lea Federal Number 5 has just been recompleted in those additional zones and the casing leak fixed, and it's up to 3000 barrels a month.

And then these two kind of poor wells, the Powell Federal in Section 4, Union A Federal in the southwest of Section 10, as you can see, that's again kind of showing the edge of the reservoir, not near the productivity that we're experiencing up in Section 2 in the North Lea Number 6.

And the last group of curves are some good Delaware wells, just typical good Delaware wells located in Lea County. I want to show that it is possible for these things to produce for a long period of time at 100 barrels a day.

The first one is a Cotton Draw well in the Paduca (Delaware), and it produced five years at 3000 barrels a month or a hundred barrels a day.

And the next Cotton Draw well produced over eight years at 3000 barrels a month.

And then the next three curves are some Inca Federal wells over in the Shugart field that are operated by Siete Oil Company, and again they produced two or three years at a hundred barrels a day before they showed any kind of decline.

Q. What is the reservoir drive mechanism you anticipate in the subject portion of the Delaware?

A. I feel like in this area, because of the better permeabilities, we're probably going to have a combination of solution gas drive and a water drive, and that's -- As you can see in the decline curves on some of the Cotton Draw wells, that they're more or less constant rate, being that they start out at about 3000 or 4000 barrels of fluid a day, 3000 oil and some water, and then they end up toward the end of their life making 3000 water and some oil.

So I think we have a similar situation here with a water leg to the south and enough permeability where we can see the effects of that water leg.

Q. Would you identify what has been marked as Armstrong Exhibit Number 11?

A. This is a volumetric analysis of the third sand in the Armstrong Energy well, trying to get an idea of what the recovery might be for 40 acres in that particular reservoir, and came up with a number of 261,000 barrels.

Q. Let's move right on into Exhibit Number 12, and I'd like you to first explain what this is and then review it.

A. Okay, this is a proposed -- or a decline curve. I think this well could possibly produce -- the way it possibly would produce at 107 barrels a day.

Using the 260-plus-thousand barrels ultimate recovery, it would produce about five years and then start some kind of decline. And I've run economics on that scenario, holding the rate constant for 5.4 years and 107 barrels a day, and then declining it.

And then the second curve is what would probably happen at a higher rate, 300-barrel-a-day allowable. It would probably produce for about a year and then go on approximately the same decline.

Q. How do the payouts compare under each of these allowable scenarios?

A. The payout at 107 barrels a day is about .82 years, and of course increasing the rate by a factor of three reduces the time by about -- to about one-third or .28 years.

Q. Why is this significant, other than just recouping your investment more quickly?

A. Well, it's significant for a couple reasons.

We want to recoup the investment early on so we have money to invest in the next well.

It also by a higher allowable is a much more efficient recovery of the reserves, because you shorten the life of the prospect or shorten the life of that particular zone from -- in this case, from 9.6 years to

6.7 years, so you save three years of lease operating expenses.

And by having a higher allowable, you would be more encouraged to complete the additional pay zones in the area.

Q. Have you experienced any kind of physical problem with the wells in this area that would -- corrosion, anything of that nature?

A. Well, I mentioned a while ago the concern we have about the Seven Rivers Reef interval. It is a very porous, lost-circulation zone that has lots of corrosive water moving around in it. And it not only causes problems drilling, but it has caused casing problems in the North Lea Federal Number 5, which has had casing leaks.

It is possible that if the life of these wells were drug out too long, that you could have a casing leak and lose the well and actually lose reserves.

Q. In view of that, is it more efficient to produce these wells at a faster rate?

A. In my opinion, it would be more efficient and prudent to produce them at as high a rate as possible.

Q. Let's take a look at Exhibit Number 13. Could you identify that, please?

A. This is copies of the logs on the Armstrong well and the Read & Stevens North Lea Federal Number 6 well, and as we've discussed previously that there are multiple pays in this field, and we feel like that each of these pays are capable of producing over the allowable.

There's two other zones in the Armstrong well, and at least two other zones in the Read & Stevens well that will be tested at some point in time.

Now, the economics we talked about previously, by not going ahead and completing those zones it will have a multiplying effect on the economics because you probably wait four or five, six years to complete those other zones and not realize any benefit from those zones for some period of time.

Q. Mr. Stubbs, in your opinion will approval of this Application prevent waste?

A. I feel like it will prevent waste and more efficiently produce the reserves from these wells.

The higher rates will mean quicker payouts.

It will reduce the operating costs, thus resulting in more capital for future investment.

Q. Okay, and what are the other benefits that are related to these quicker payouts?

A. Well, like we stated before, there are problems in drilling these wells that add about $100,000 to the cost in additional casing and lost-circulation problems in the Seven Rivers Reef zone.

Because it costs more to drill these wells, there has been a reluctance to develop this area.

Higher allowables would generate more cash flow, which would be an incentive to go ahead and develop these wells.

Q. How would this lost-circulation problem, if you would state again, affect this overall Application?

A. Well, it's my concern that later in the life of the wells, if you have casing leaks, you could jeopardize a wellbore and you'd actually lose reserves.

Like I said before, we've had two cases where we've had casing leaks, and it's a distinct possibility that we're going to see more casing leaks as time goes on.

Most of the deep wells in the area have two strings of casing, so they have not experienced that kind of problem. But the shallower wells don't have the benefit of the deep intermediate through that zone to protect the production casing.

Q. If you encounter these problems with corrosion, could that in fact result in premature abandonment and ultimately loss of reserves in this area?

A. I believe it could.

Q. Mr. Boling testified about four zones capable of production in this portion of the Delaware. How does that factor, in your opinion, affect this Application?

A. Well, it would be more efficient to produce all the zones at the same time and not delay completion or production out of those zones for a number of years. It would just be more efficient to go ahead and produce them all together, and it would save operating costs and reduce exposure to casing failures.

Q. Will approval of the Application cause reservoir damage?

A. I don't believe it will. The zones appear to be highly productive, the pressure drawdowns are not great, and we see no evidence of water influx or increased GOR ratios.

Q. Will approval of this Application protect correlative rights?

A. I believe it will, because most of the productive area lies on the Armstrong lease and on the Read & Stevens leases. And Read & Stevens, I believe, is in support of this Application for higher allowables.

Q. If the Division should decide to grant temporary rules for this pool, for how long a period do you think temporary rules should remain in effect prior to being called back to provide additional data on the performance of wells in the reservoir?

A. Well, it's probably going to take another six months to get a couple more wells drilled and get additional pay zones opened up.

And then I think you'd want to see at least 12 months, maybe 18 months of production, so you can get some idea of what kind of reservoirs you have and what kind of drive mechanisms and what the actual declines are going to be.

So a minimum of 18 months and preferably probably two years.

Q. Would you identify what has been Marked Armstrong Exhibit 14?

A. That's just a summary of our main reasons for requesting higher allowables.

Q. Is Exhibit Number 15 a copy of an affidavit confirming that notice has been given to all operators and unleased mineral interest owners, if any, in the pool?

A. That's correct.

Q. And also notice has been given to operators of wells within a mile of the pool?

A. That's correct.

Q. What is Exhibit Number 16?

A. I believe that's the letter from Read & Stevens in support of our Application for higher allowables.

Q. Were Exhibits 5 through 16 either prepared by you or compiled under your direction?

A. That's correct.

MR. CARR: At this time, Mr. Catanach, we move the admission of Armstrong Energy Corporation Exhibits 5 through 16.

EXAMINER CATANACH: Exhibits 5 through 16 will be admitted as evidence.

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

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Stubs, am I correct in my understanding that the wells producing from the Quail Ridge Delaware field are in fact not in communication with the Lea field?

A. The North Lea Federal Number 6, located in the northwest of the northeast of 10, is producing out of the same sand as the Armstrong Energy well, and so those two are probably going to be in, you know, the same interval.

Now, they're quite a distance apart. The ones located over in the southwest of Section 3 are producing, I recall, in the first sand, and the Armstrong well is not completed in that sand at this time.

Q. The sands are continuous over that area, and they could possibly be in communication with the Armstrong well?

A. The first sands, yes, and also the third sand that we see in Number 6, Lea Federal. Those sands, I think, are -- as Mr. Boling stated, are continuous over that area.

Q. None of the wells in the Quail Ridge Delaware field are capable of the rates of production you're seeing in the Armstrong well?

A. Yes, they are.

Q. They are?

A. They're not capable of 300 barrels a day, but they can produce well over 100 barrels a day.

As we can see in the decline curve, they have pretty stable production at 107 barrels a day, 3000 barrels a month.

Q. In your opinion, would raising the allowable in your field have an adverse effect on those operators in the Quail Ridge Delaware field?

A. I don't believe it would at this time. The Armstrong Energy well is 1980 feet away from the west line of Section 2, so it's at this time quite some distance from the Read & Stevens leases.

The Harken well has already tested the third sand and found it to be wet. So it won't affect anything in the Harken acreage.

Q. I presume Armstrong will propose to drill more wells in this field?

A. That's correct.

Q. Probably closer to the Quail Ridge field?

A. That's probably correct, yes.

Q. Mr. Stubbs, in your various production scenarios, 107 barrels a day versus 300 barrels a day, have you determined what the ultimate recovery would be in each of those cases?

A. Well, I held the ultimate recovery basically constant in the two cases at a little over 260,000 barrels, based on a volumetric analysis.

Now, because it's more efficient and you can get the production out earlier in the life of a well, it's possible that your operating costs would be lower early in the life of a well, and you could go ahead and produce the well past what we've picked as the economic limit of this case, so you could have more reserves at a higher rate under that scenario.

Q. Could have more reserves --

A. -- at a higher rate.

Q. Could you also have less reserves?

A. Anything's possible. We don't know at this time.

Q. Is there not a way to estimate, based on the projected decline curves, what the recoveries might be from these wells?

MR. STOVALL: The decline curves, as I understand the way you did them, though, were based upon the projected ultimate recovery rather than the reverse, right?

THE WITNESS: Right, right. We don't have enough production history on this well to really have any kind of decline-curve analysis. We have two months' production, and it's basically flat.

MR. STOVALL: Let me ask you -- I think what the Examiner may be getting at is, do you have an opinion as to whether the producing at the higher rate could cause an earlier depletion of, I guess, reservoir energy of some sort, or do something in a physical way, rather than an economic way, to reduce the potential ultimate recovery?

THE WITNESS: I don't believe so at this point in time.

There's quite a few cases where the Delaware is producing large volumes of fluid and it doesn't appear that they've been harmed in any way. Like in the Paduca (Delaware) field, they're producing 200 or 300 barrels of fluid a day down there out of the Delaware, and it's --

MR. STOVALL: In other words, it's not rate-sensitive as far as ultimate production?

THE WITNESS: No, it doesn't appear to be.

The mobility ratio between the water and the oil is about the same. The viscosities of the fluids at reservoir conditions are about 1.2 centipoise, and the water is about 1.2 centipoise.

So there's no reason the water is going to override the oil, and I just don't feel like it's going to be a problem.

Q. (By Examiner Catanach) At a rate of 300 barrels of oil per day, how long would it take you to finally establish a decline?

A. Well, if it follows my scenario, about a year, and then it would start showing some kind of decline.

But I think before that year was up, the other zones would probably be completed, and that might extend on farther past that.

Q. Which leads me to a next question. Would Armstrong propose that the various sands in the same wellbore be completed simultaneously?

A. If our higher allowable was available, it would be prudent to go ahead and complete all the sands at the beginning of the well, I think.

Q. Which may reduce the volume of oil you're producing from a single zone?

A. That's correct. You may -- If it was 300-barrel-a-day allowable, you may have, just for example purposes, 100 barrels a day out of each of the three intervals, if you had three intervals completed.

Q. Now, assuming that that was not the case, assuming you had a well that could not produce from the third sand and you wanted to complete in a different sand, you really haven't done an analysis of any of the other sands to see what kind of effect a higher producing rate would have on those reservoirs?

A. I've looked at the first sand completions over on the Mark Federal wells. And again, they're not as highly productive as this well, but they would benefit from the same scenario, being able to produce at a higher rate.

Q. But have you done an analysis to determine whether that higher rate would be detrimental to the reservoir?

A. No, I have not.

Q. We are talking about four distinct and separate reservoirs?

A. That's correct.

Q. If you were producing at a 300-barrel-a-day rate, what evidence, if any, would you see if you were causing excessive water-coning in the reservoir?

A. If you had water-coning, of course, you'd see an increase in water production, and your percent water cut would increase.

We haven't -- Like I said, in our production tests, we have seen no increase in the water rates, water percentages.

Q. Do you believe that the test period that you've done in the Number 1 well is sufficient to demonstrate that there's no harm being done to the reservoir?

A. It's -- Well, it's two months, and that's a fairly long production test, and we've watched it pretty close. If there was going to be a drastic problem, I think we'd have seen some kind of indication of water increases.

But we're quite a ways away from really the water leg itself, because we're -- This well is quite a ways updip.

EXAMINER CATANACH: I believe that's all I have.

MR. STOVALL: Mr. Carr, you're the one that provided the Affidavit of Notice.

MR. CARR: Uh-huh.

MR. STOVALL: Do you have sufficient information to say that that is everybody who would be entitled to notice under the --

MR. CARR: We believe we've given notice to everyone who is entitled to notice under Division rules.

We did not expand this to the Uhden test because we could not find anyone who would be personally affected by this.

The royalty owners in the area are only the state and the -- level.

MR. STOVALL: Well, I don't think the royalty owners are affected, because I don't think it changes --

MR. CARR: And so what we have done is, we have given --

MR. STOVALL: -- their interest.

What about within a mile of the pool?

MR. CARR: We've given to all operators of wells within a mile, as required by the rules.

MR. STOVALL: Okay. Yeah, I agree with you, I don't think it's a Uhden royalty owner case at all.

MR. CARR: And I don't believe there are unleased mineral tracts within the 480 acres, and so we have covered everything required by --

MR. STOVALL: Anybody that owns a working interest within the pool and a mile thereof.

MR. CARR: Well, either the owner or their operator has been notified.

MR. STOVALL: Yeah, okay, right.

EXAMINER CATANACH: Within a mile of the pool boundary?

MR. CARR: Yes.

MR. STOVALL: That's really the one we were focusing on, is the mile, more than --

MR. CARR: It says operator of wells within a mile, and they've been covered, because there aren't wells over there.

MR. STOVALL: Right. Well...

EXAMINER CATANACH: Is that it?

MR. CARR: That's all we have.

(Off the record)

EXAMINER CATANACH: There being nothing further, Case 10,653 will be taken under advisement.

(Thereupon, these proceedings were concluded at 12:20 p.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 10653, heard by me on January 7 1993.

David R Catanach, 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 January 10, 1993.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1994

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

APPLICATIONS OF ARMSTRONG ENERGY CORPORATION

CASE NOS. 10,653
10,773

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

BEFORE: WILLIAM J. LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
JAMI BAILEY, COMMISSIONER

FEB 1 1 1994

January 13, 1994

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on Thursday, January 18, 1994, at Morgan Hall, State Land Office Building, 310 Old Santa Fe Trail, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

January 13, 1994
Commission Hearing
CASE NOS. 10,653 and 10,773



* * *

# E X H I B I T S

| | Identified | Admitted |
|---|---|---|
| **APPLICANT'S:** | | |
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| Exhibit 2 | 15 | 34 |
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* * *

A P P E A R A N C E S

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* * *

WHEREUPON, the following proceedings were had at 9;24 a.m.:

CHAIRMAN LEMAY: We will call the Cases Number 10,653 and 10,773.

MR. STOVALL: 10,653 is the Application of Armstrong Energy Corporation for special pool rules, Lea County, New Mexico.

10,773 is the Application of Armstrong Energy Corporation for pool extension and abolishment, Lea County, New Mexico.

CHAIRMAN LEMAY: Appearances in Cases 10,653 and 10,773?

MR. CARR: May it please the Commission, my name is William F. Carr with the Santa Fe law firm, Campbell, Carr, Berge and Sheridan.

I represent Armstrong Energy Corporation in each of these cases and request that they be consolidated for the purpose of hearing.

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Additional appearances?

MR. BRUCE: Mr. Commissioner, Jim Bruce from the Hinkle law firm in Santa Fe, representing Read and Stevens, Inc.

I have two witnesses. There's no objection to the consolidation.

CHAIRMAN LEMAY: Thank you.

Would those witnesses please stand, raise your right hand to be sworn in?

(Thereupon, the witnesses were sworn.)

CHAIRMAN LEMAY: Okay? Mr. Carr, you may begin.

MR. CARR: May it please the Commission, at this time we would call Mike Boling.

ROBERT M. BOLING,

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. Robert Michael Boling.

Q. And where do you reside?

A. Roswell, New Mexico.

Q. By whom are you employed?

A. Armstrong Energy Corporation.

Q. And in what capacity are you employed by Armstrong?

A. As a consulting petroleum geologist.

Q. Mr. Boling, have you previously testified before the New Mexico Oil Conservation Commission?

A. Before the Division, not the Commission.

Q. Could you briefly summarize your educational background and then review your work experience for the Commissioners?

A. I have a bachelor of science degree in geology from New Mexico Institute of Mining and Technology.

My early work experience was with a geophysical subsidiary of Texas Instruments. I started working in 1973. My first job assignment was in Peru. I worked on a helicopter-supported seismic crew in the Amazon Basin for two years.

I returned to Houston in the employ of GSI, became -- worked on a land data- -- seismic data-processing crew in Houston, processing data from all onshore and shallow water Gulf Coast of the United States.

In 1977 I was transferred to Denver, at which time I became the in-house technical consultant to all of our customers in the Rocky Mountains with respect to any technical help they needed in designing geophysical parameters or quality control management of their seismic crews while we were under their employ.

In 1981 I went to work for Phillips Petroleum as an exploration geophysicist. I was assigned in Denver. I worked Alaska, I worked both on and offshore, Bering Sea, Beaufort Sea, special projects in the Prudhoe Bay unit, also in the Cook Inlet.

In 1983 I moved to Roswell and became an independent petroleum geologist, and in the last ten years that I have been in Roswell, I have participated in prospects or projects in New Mexico, Texas, Oklahoma, Kansas, Nebraska, Colorado, Montana, Wyoming, California, Oregon and Alberta, Canada.

Q. Are you familiar with the Applications filed in each of these cases?

A. I am.

Q. Are you familiar with the Northeast Lea-Delaware Pool and the Quail Ridge-Delaware Pool?

A. I am.

Q. Have you made a geological study of these pools?

A. I have.

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

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Carr) Mr. Boling, would you briefly state what Armstrong Energy seeks with this Application?

A. Armstrong Energy seeks to abolish the Quail Ridge-Delaware Pool, to extend the boundaries of the Northeast Lea-Delaware Pool to cover the area now covered by the Quail Ridge-Delaware Pool, and we seek adoption of special pool rules for the Northeast Lea-Delaware Pool, including a special oil allowable of 300 barrels a day.

Q. Briefly summarize for the Commission the rules that currently govern development in these --

A. In both the Quail Ridge-Delaware Pool and the Northeast Lea Pool, statewide rules apply. There are standard 40-acre spacing units, standard depth bracket allowables, 107 barrels a day, 2000-to-1 gas/oil ratio, and both pools are governed by the same rules.

Q. This case came before a Division Examiner in January of 1993?

A. That's correct.

Q. Were you a witness at that time?

A. I was.

Q. What was Armstrong seeking in that case?

A. In that case we were seeking the special oil allowable for the Northeast Lea-Delaware Pool of 300 barrels per day.

Q. And that case was -- or application was denied in February of last year?

A. That's correct, by Order R-9842.

Q. This case is different in that you have extended the Application to basically consolidate the Northeast Lea-Delaware Pool and the Quail Ridge-Delaware Pool?

A. That's correct.

Q. Could you briefly summarize for the Commission what has occurred since Order Number R-9842 was entered denying Armstrong's original request?

A. In both the -- A combined total of nine new wells have been drilled in the two fields by the two primary operators, Read and Stevens of Roswell, and Armstrong Energy of Roswell.

We have also -- Armstrong Energy is also undertaking an extensive and exhaustive testing program as requested by the Commission -- by the Division at our previous hearing, to try to determine drive mechanisms in the reservoir, the productivity of the reservoir, and gas/oil ratios and whether or not an increased -- extended increased productivity harmed the reservoir in any manner. And this testing has been taking place over the last year.

Q. The original Order denying the Application, recommended that the pools, the two pools, be treated as one common source of supply; is that correct?

A. That is correct.

Q. And that is the reason that the additional Application was filed to address the Quail Ridge as well as the Northeast Lea-Delaware Pool?

A. That's correct.

Q. What has caused the delay in bringing this matter to the Commission for review?

A. Well, originally when we came before the Division in January of 1993, we had support from offset -- the offset operator in the Quail Ridge field -- that's Read and Stevens -- supporting the increased allowable, and we have a letter to that effect.

Subsequent to that agreement, Read and Stevens became concerned about the oil allowable being raised, and they changed their position.

After that, Armstrong sought and received authority from the Division to conduct a special production test on the Mobil Lea State Number 2 Well, and agreed to continue this hearing to such time that Read and Stevens had subsequent time to drill additional wells to try to determine the extent of the reservoir that was in question.

As a part of that agreement to allow Read and Stevens to drill their subsequent wells, Read and Stevens agreed not to seek make-up of the overproduction accumulated by Armstrong during the production testing phase of the Mobil State Number 2 well, and Read and Stevens has agreed to this.

Q. Now, you're talking about an agreement with Read and Stevens?

A. Correct.

Q. And also authority to run certain tests that were granted by the Oil Conservation Division?

A. That's correct.

Q. Have those tests in fact been run?

A. Yes, they have.

Q. Has Read and Stevens drilled additional wells in the field?

A. Yes, they have.

Q. And are you ready to present the data that you've accumulated this year on the formation to the Oil Conservation Commission?

A. Yes, we are.

Q. We're going to now start looking at the exhibits that have been prepared by Armstrong Energy Corporation.

There is not initially an orientation plat. The orientation plat is contained in the engineering exhibit, which is Exhibit Number 10, and it is at page B-1. The pages are numbered.

And it might be helpful to open to that, because as we work through both the geological and engineering presentations, it may help orient the Commission as to exactly what portion of this common source of supply we're actually talking about.

All right, Mr. Boling, let's go to what has been marked Armstrong Energy Corporation Exhibit Number 1. Would you identify this and review it for the Commission, please?

A. Yes, sir. Exhibit Number 1 is a type log from the Northeast Lea-Delaware Pool. It is a compensated neutron density log on the left -- there is a dual lateral log on the right -- from the Mobil Lea State Number 2 Well, which is located in the northwest of the southwest of Section 2, 20 South, 34 East.

The purpose of the type log is twofold: One is to familiarize you with the nomenclature which we use, which is slightly different than the nomenclature that Read and Stevens is going to use when we talk about this in the future. We have simply named these four major producing -- four major sands the first, second, third and fourth. Each of these sands is annotated, and the dark, heavy line is indicating the base of each of these intervals.

The two primary reservoirs in the Quail Ridge-Delaware Pool and the Northeast Lea Pool are illustrated on this log.

The uppermost sand, labeled "first sand" or "base of the first sand", that sand immediately above that annotated line is the main producer in the Quail Ridge Delaware field. It is productive in the south half, south half of Section 3 and north half of Section 10 in 20 South, 34 East, and also in one well in the east half of Section 2, in this northwest of the southeast of Section 2.

The second major reservoir, which is the primary reservoir in the Northeast Lea-Delaware Pool, is annotated between 5900 feet and 6000 feet. We have called this the third sand. This sand is productive in the west half of Section 2, also in the northeast northeast of Section 2 and in several wells in the north half, north half of Section 10, on Read and Stevens' acreage.

The other thing to note is, on the resistivity log you will notice that in the interval that lies between the base of the first sand and the top of the third sand is a sand that we have called the second sand. In this well it's approximately 80 feet thick. This sand occurs between 50 and 200 feet thick and is extensive across both pools.

You will notice in the resistivity log that it -- I apologize for the poor quality of the copy here, but it is obviously wet. It shows two ohms of resistivity, while the sands above and below obviously show higher resistivities. And in fact, the third sand is extremely productive in this well, and we had shows in the first sand.

It is important to note that between the two primary reservoirs in these two pools, you have a thick, wet sand along with two carbonate barriers. The base -- Below the base of the first sand and above the top of the second sand is a carbonate barrier that varies from 12 to 40 feet thick across the area, and at the base of the second sand and above the third sand there is another carbonate barrier that is approximately 30 feet thick across the area.

These are -- The first and third sands are the two major reservoirs in these two pools.

There is no way that production from one of these reservoirs can affect production in the other reservoir. We have two significant carbonate barriers between, plus a thick, wet sand that separates these two reservoirs throughout the area.

We will discuss the nature of the second sand and where it's been tested and why we think it's wet everyplace out there in a minute.

Q. Mr. Boling, let's go now to Armstrong Energy Corporation Exhibit Number 2, the net isopach on the first sand, and I would ask you to review that exhibit for the Commission.

A. The next three maps are just -- are going to be net isopach maps, net porosity isopach maps of three of the four sands.

The purpose of these isopach maps is to show the extensive nature of the reservoir across the pools in the area.

This is, as annotated, the first sand interval. This is porosity at or greater than 15 percent. As you can see, it's quite thick, with a thick plot of sand in the south half, south half of 2, another one in 9, and wells that are productive in this reservoir in the south half, south half of 3 and the north half of 10.

It is important to note that Read and Stevens' wells are all -- all of their wells are producing at least out of this reservoir.

There is one well in the east half of 2, which is annotated 66 feet, which is the Mid-Continent Exploration Well Number 1. It has produced about 76,000 barrels out of this reservoir.

It is also important to note that in five of the six wells that Armstrong Energy has in Section 2, this first sand occurs, has shows in them. We have mud log shows and geophysical log responses that indicate that this sand will be productive in each of those wells on Armstrong's acreage.

Q. All right. Let's go now to the next Exhibit, Armstrong Exhibit 3, the net isopach on the second sand.

A. This is the net isopach map of the second sand, again showing the extensive nature of the sand.

As you can see, it's quite thick, varying from 50 to 176 feet in Section 10, and approximately 60 to 110 feet in Section 2.

This sand has been -- Completion attempts have been made in this sand in three wells. The Mark Federal 5 and 8 in Section 10 both produced water. And also

Armstrong's West Pearl State Number 2, which is in the -- is the well in the southwest of the northeast of 2, annotated "76".

This sand has been attempted in these three wells on the east edge of the field -- east edge of the sand accumulation in the West Pearl State 2 and near the center of the -- to the westerly side of the accumulation in Section 10. It produced water all three times, and every log of every well out here is wet in this interval.

This sand is extremely fine-grained and appears not to be permeable to oil. It's full of water.

The actual zone, a correlative carbonate zone, does produce from this interval in the southeast southeast section of -- southeast southeast proration unit of Section 35. It is the Pennzoil Mescalero Ridge Unit Well Number 3. It has produced approximately 26,000 barrels out of this carbonate interval.

Q. All right. Let's skip now the third sand and go to Exhibit Number 4, which is the net isopach on the fourth sand.

A. Yeah, the fourth sand, you see that it is not nearly as extensive nor as thick as the previous sands. In fact, it occurs mainly in Section 2 in the east half of Section 10. It is not a significant producer. In fact, there is only one well that may be producing out of this interval.

It has been uniformly wet in all the wells that Armstrong has drilled in Section 2 and is not a significant reservoir in this area -- in either of these two pools.

Q. All right. Let's go now back to the third sand, and let's start with the structure map, Armstrong Exhibit Number 5.

A. The third sand is, as I mentioned, the primary producing sand in the Northeast Lea-Delaware Pool.

The first map is a structure map on the base of the interval.

There are several significant characteristics that are revealed by this map. The first is, it is evident that there are two major and one minor --

COMMISSIONER WEISS: Which exhibit are you at?

THE WITNESS: I'm at 5, that one.

COMMISSIONER WEISS: That's titled "Cherry Canyon"?

THE WITNESS: Yes, "Base of Producing Interval".

Let's see. Look at the annotation and see if it says "Structure Map, Base of Producing Interval".

COMMISSIONER WEISS: Yeah.

THE WITNESS: Okay, that's the one we're on. Are you ready?

COMMISSIONER WEISS: Yeah, go ahead.

THE WITNESS: Okay. As I said, there are several important characteristics that this map shows us.

The first is that there are two major and one minor depositional pathways etched in the carbonate that lies underneath the base of this sand.

The first one begins in the southwest quarter of Section 3 and transects Section 10 to the southeast and terminates in the southeast quarter of 10 and the southwest quarter of 11.

There is another major depositional pathway that runs north/south across the west half of Section 2. It terminates in the northwest quarter of Section 11.

There is a minor depositional pathway that runs north/south from Section 35 down into the northeast quarter of Section 32. There is minor sand accumulation in that depositional pathway. There's 24 feet of porosity greater than 15 percent in the well in the northeast northeast quarter of Section 2, and none of the other wells in the east half of 35 have any sand present. So this is a minor depositional pathway.

It's important to note these two depositional pathways, because this is where the two sand thicks are going to lay, where the primary producing reservoir will be out here.

The other significant topographic feature that this map shows is a nose that runs between these two depositional pathways and lies in the southeast quarter of Section 3, the northeast quarter of 10 and the northwest quarter of 11.

This topographic nose separates these two depositional pathways and acts as a topographic barrier to any kind of sand that would be deposited and crossing that nose. There is no sand deposited on top of that nose, and we know that by well drilling information.

If you will look at the well that's in the northwest of the southwest of Section 2, annotated minus 2321, that is Armstrong Energy's Mobil Lea State Number 2 well. In the third sand that well has 97 feet of porosity greater than 15 percent.

You will note the well immediately to the west of it, which is the Read and Stevens Number 8 well, annotated minus 2320. There's two feet of sand in that well. That well is on the flank of the nose.

This well information, plus the mapping, indicates there is no sand on top of that nose, so that there is no horizontal connection in the oil leg between the third sand reservoir in the depositional pathway on Read and Stevens' acreage and the one in the west half of 2 that's on Armstrong's acreage.

This nose is extremely important, and it serves as the topographic barrier to these two sand bodies.

Q. (By Mr. Carr) All right, let's go now to the structure map on the top of the third sand.

A. The next map is the structure map on top of the producing interval. This map is not a significant exploration, but it does show the same features as the map on the base of the interval.

You see the depositional pathway, clearly evident in Section 3 and 10, running to the southeast. Also, the one in Section 3 -- in the west half of Section 2, running north-south.

As you will note, each of these depositional pathways have minor perturbations or re-entrants running into them. Those little re-entrants sometimes have sand in them and sometimes don't.

As noted, on the flank of that nose, the Number 8 well had two feet of sand in it. On the other side of the nose, on Read and Stevens' well in Section -- in unit letter P, annotated minus 2231, there's approximately 76 feet of sand.

Another indication that there is no sand on that nose is the placement of Read and Stevens' well in P of 3, the Number 4 Well.

That well was originally staked 660 in the middle of that proration unit. It was then amended to be 990 from the south and 330 from the east, to be closer to our wells.

After the well to the north that was drilled with two feet of sand in it, the location was amended again and moved at 990 from the east and 330 from the south, moving it further away from the nose and trying to get in a position where they would find sand.

Q. Now, that's Exhibit Number 6 that you've just addressed?

A. Yes.

Q. That does not define the topographic conditions on which the sands were actually laid down, but it does show, basically, the same picture of the Delaware as Exhibit number 5?

A. Yes, that's true.

Q. All right, let's go now to Exhibit Number 7, and I'd ask you to identify that first and then review it for the Commission.

A. Exhibit Number 7 is the net porosity isopach map on the third sand, the main producing intervals in the Northeast Lea-Delaware field.

As you can see, and as one would expect, there are two sand thicks that correspond with the two depositional pathways.

The thick in Section 3 and 10 is -- approaches 100 feet thick and runs northwest-southeast in the center of the depositional pathway and terminates down in the southeast quarter of Section 11 -- southwest quarter of Section 11, as you would expect, corresponding with a depositional pathway.

The same is true in the west half of 2. A major thick running north-south in the center of the depositional pathway in the west half of Section 2, terminating also downdip in the water leg in the west half of Section 11.

It is again important to note that there is only two feet of sand in the well in the northeast of the southeast of Section 3, while we have offset that well with two wells that have 98 and 94 feet of sand in them.

We have dipmeter information in three of the four wells in the southwest quarter of Section 2.

In the two wells in the west half of the southwest quarter of Section 2, the two wells annotated 94 and 98 feet, dipmeter indicates straight south dip, which is telling us that the sand thick is to the north.

The well annotated in the northeast of the southwest of Section 2, annotated 86 feet, has dipmeter information dipping to the southeast indicating thickening to the northwest.

The map, the drilling information and the dipmeter information all indicate that this sand is restricted to the west half of Section 2. It's going to run north-south.

We know that we have wells to the west with two feet of sand and wells to the east of us with as little as 18 feet of sand. We know where the sand is; it's in the west half of 2. It is not --

CHAIRMAN LEMAY: Could I stop you just a minute? I'm sorry. Your Exhibit Number 7, which I think you're talking about --

THE WITNESS: Yes.

CHAIRMAN LEMAY: -- is there -- does it say what sand you're isopaching here?

THE WITNESS: Yeah, the producing interval -- It says "producing interval". It's the third sand, is what we're talking about. The last three maps --

CHAIRMAN LEMAY: So under "producing interval", that title should be also "third sand"?

THE WITNESS: Yes, sir.

COMMISSIONER BAILEY: How about for the previous exhibits?

THE WITNESS: It's the same. For the previous two exhibits the producing interval is the third sand. Excuse me.

CHAIRMAN LEMAY: I'm sorry, just for clarification.

THE WITNESS: That's fine.

Anyway, to reiterate, dipmeter information, well information and mapping indicates that the sand is restricted to the west, and this sand in this depositional pathway is restricted to the west half of 2 and is not connected to the sand in Sections 3 and 10 in the oil leg. They are connected downdip in the water leg, but not in the oil leg.

So there's no horizontal connection of these two sands in the oil leg.

Q. (By Mr. Carr) Now, Mr. Boling, let's go take out the cross-section, which is the large exhibit. That's Exhibit Number 8.

A. Okay.

Q. After we get that out, I'd ask you then to review the information on the exhibit for the Commissioner.

A. This cross-section is quite long. I don't know if all of you want to unfold all of them or not.

Q. All right, Mr. Boling. First tell us what this is.

A. This is a cross-section that traverses the producing wells in the Northeast Lea-Delaware field and several of the producing wells in the Quail Ridge field in Section 10.

Q. And you have an index map on this exhibit?

A. And I have an index map from A' to A, A' on the northeast.

Q. Now, what have you shown generally on the cross-section?

A. What are annotated on these logs are the base of the first, base of the second and base of the third, base of the fourth sand, the oil/water contact, as we have determined it in the third sand, and also the perforations in each of the wells.

Q. Now, before we get into that, on the West Pearl Number 1, perforations need to be added, correct?

A. Correct.

Q. And that is which well on the cross-section?

A. The second well on the cross-section. It's the West Pearl State Number 1. The perforations are not on that well, but they are from 5890 to 5910.

Q. All right. Could you briefly now review this exhibit for the Commissioners?

A. The first well on the right, Pennzoil Mescalero Ridge Number 3, is in the southeast southeast of 35.

This is a well is productive out of the carbonate interval that corresponds to the second sand. As you can see, there's only tight sand in this well. The well is perforated in a limestone interval and has produced about 26,000 barrels since its inception day.

The next well to the left is the West Pearl State

Number 1, which is in the northeast northeast of Section 2.

This sand -- As you can see, this well has no first sand, no second sand present, only a remnant of the third sand, and the fourth sand. This well was perforated in the remnant of the third sand and is currently producing about 48 barrels a day.

The next well is the Armstrong Energy West Pearl State Number 2, which is in the southwest of the northeast of 2.

As you can see again, here the second sand is present, but only a remnant of the third sand is present and some porous carbonate above it. We have passed into a facies change from one depositional pod, and we're going to pass into the next one. This sand was perforated in the remnant. It is currently making about 25 barrels a day.

The next well is the Harken Energy Corporation Mobil State Number 1, the discovery well for the Northeast Lea-Delaware Pool. It is in the northwest of the southeast of Section 2.

As you can see, it has a very thick first sand interval, 66 feet thick. It's been perforated in that interval. It has a fairly thick second sand. It only has 18 feet of the third sand present, all below the oil/water contact. This well has made about 76,000 barrels from that first sand interval.

CHAIRMAN LEMAY: How much? I'm sorry?

THE WITNESS: 76,000.

The next well is Armstrong Energy Corporation Mobil Lea State Number 1, the first well that Armstrong Energy drilled in the Northeast Lea Pool.

As you can see, there's a remnant. We have lost quite a bit of the first sand, from 66 feet down to about 18 feet. The second sand is slightly thicker, but the third sand is significantly thicker. We've gone from 18 feet of porosity in the Harken well to 86 feet in the Mobil Lea State Number 1. You can see the perforations there.

This well -- During initial testing phase of this well, the first two or three days of testing, this well made in excess of 500 barrels a day.

The next well is the Armstrong Energy Corporation Mobil Lea State Number 2.

As you can see, again we have thinned in the second sand, but still a thick, wet second sand with a carbonate barrier below it and above it, separating our main producing reservoir, the third sand, from the first sand above it.

The third sand in this well is 97 feet thick. You can see the perforations there. This well also -- it IP'd -- We IP'd the well for 211 barrels a day. It also has the capability of producing in excess of 500 barrels a day.

The next well is the Spectrum 7 Exploration Mobil State Number 2 Well, the dryhole in the southeast of the southwest of Section 2.

As you can see, again a quite thick second sand interval, thick carbonate above it, thick carbonate below it, approximately 76 feet of sand in the third sand, but only 18 feet above the oil/water contact.

We recently sought approval from the Division and received approval to drill an unorthodox well offsetting this well in which we moved about 300 feet to the northwest of this well and went from 18 feet above the oil/water contact to 46 feet above the oil/water contact.

We have recently completed that well. We have four days of productive history. It's been producing in excess of 200 barrels a day, this week.

The next well is the Mobil Lea State Number 3 Well.

As you can see again, thick, wet number two sand, thick carbonate below it, above it. Also about 97 feet of sand in the third sand in this -- porosity in this third sand in this well, not quite as much above the oil/water contact, about 26 feet. This well is capable of producing in excess of 200 barrels a day routinely.

The next well is the Read and Stevens Mark

Federal Number 4, which is in the southeast southeast of Section 3.

It has 76 feet of third sand interval, as you can see, a few feet above the oil water contact. This well was completed in December of 1993 for about 92 barrels a day.

Again, even on Read and Stevens' side, you see a thick carbonate barrier between the second and third sand. A carbonate barrier is present between the second and the first sand. It's not as thick in this particular well, but there is carbonate barriers, and the thick wet sand present between the two primary reservoirs on all the acreage.

The next well is the Read and Stevens Federal Number 10. It was also completed in the third sand. It tested about 26 feet above the oil/water contact. It IP'd for 56 barrels a day in April of 1993.

The next well is the North Lea Federal Number 7. As you can see, quite a thick third sand interval, all below the oil/water contact. A completion attempt was made in this well. It was swabbed a hundred percent water.

The next well is the North Lea Federal Number 6 in Section 10 of 20 South, 34 East.

As you can see, again about 26 feet above the oil/water contact in the third sand. This well has been completed in the third sand. It IP'd for about 117 barrels a day in April of 1993. Again, a thick carbonate interval above it, between it and the thick, wet second sand.

And the last well is the North Lea Number 5. As you can see, the third sand is now gone. We're out of the depositional channel and we're into the dolomite facies, no third sand present.

This well is one of the wells where the thick, wet second sand was attempted. You can see the perforations there at 5812. This well swabbed 100 percent water in that second sand.

Q. (By Mr. Carr) All right, Mr. Boling. What conclusions can you reach from your geologic study of the Delaware formation in this area?

A. My conclusions are, we have two primary reservoirs that are quite extensive across the Northeast Lea and Quail Ridge fields. Our nomenclature calls them the first and third sands.

They're extensive across a wide area of these two pools. They're prolific, both the first and the third are prolific. They are separated, consistently separated by a thick, wet second sand and two carbonate barriers so that there is no vertical connection between these two reservoirs.

We have drilling and mapping information that tell us that across the topographic nose in the southeast of Section 3 and northwest of Section 10, no sand occurs.

We have a well that goes from 97 feet of porosity to two feet on the flank of that nose, and we have evidence that Read and Stevens moved their location away from that nose, trying to get sand.

We have plenty of evidence, geologic evidence, that says there's no sand on that nose. If there's no sand on that nose, there is no horizontal connection of the third sand reservoirs in these two depositional pathways. They're connected hydrologically in the water leg, but not in the oil leg.

We also know that they're not vertically connected because in many of -- in several of the wells that Read and Stevens has, they completed in the third sand and then went up and completed in the first sand and got increased production, which indicates that we have two separate reservoirs, two different sources of supply.

We would have to -- for Armstrong to produce oil in the third sand reservoir out of -- off of Read and Stevens' acreage, we would have to pull -- Since there is ample evidence that no sand occurs across the topographic nose in the high there, we would have to pull the oil down through the water leg around that nose and back up into our acreage, and I find that extremely difficult to conceive of a mechanism that would allow us to do that.

So in my opinion, there is no connection in the third sand reservoir, in the oil leg, between the depositional pod and the sands that occur in Section 3 and 10 and the one that occurs in the west half of Section 2.

Q. Is Exhibit Number 9 an affidavit confirming that notice of this hearing has been provided as required by Oil Conservation Division Rules?

A. Yes, it is.

Q. And to whom was notice provided?

A. All operators in both pools.

Q. And there are no unleased tracts in either of these pools?

A. That's correct.

Q. How close is the nearest Delaware production outside what are now the established pool boundaries?

A. Eight miles to the southwest in the Hat Mesa field.

Q. Will Armstrong also be calling an engineering witness in this case?

A. Yes, they will.

Q. Were Exhibits 1 through 8 prepared by you?

A. Yes, they were.

Q. And Exhibit 9 is the notice affidavit?

A. Yes, sir.

MR. CARR: At this time, may it please the Commission, we would offer into evidence Armstrong Energy

Corporation Exhibits 1 through 9.

CHAIRMAN LEMAY: Without objection, those exhibits will be entered into the record.

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

CHAIRMAN LEMAY: Thank you, Mr. Carr.

Mr. Bruce?

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Boling, if you could keep your Exhibits 5 and 7 handy --

A. Okey-doak.

Q. -- that's the only ones I have questions on as far as --

A. Okay.

Q. A part of your Application is to abolish the Quail Ridge and extend the Northeast Lea?

A. That's correct.

Q. Okay. So I presume you're saying that the pays in the Northeast Lea-Delaware correlate with those in the Quail Ridge?

A. I beg your pardon?

Q. The pay zones in the Northeast Lea correlate with those in the Quail Ridge?

A. That's correct.

Q. Okay.

A. We are actually -- For the record, we were directed by the Division in their Order to treat these two pools as one. That is why we made it part of our Application.

Q. Looking at your Exhibit 7, that is the isopach on your third zone; is that correct?

A. Yes, sir.

Q. Okay. Looking at the wells in the southwest quarter of Section 2 and then in the southeast quarter of Section 3 --

A. Yes, sir.

Q. -- what is -- and I don't have the names, but I'm looking --

A. Okay.

Q. -- the well that has your well, that has a "98" by it. What is the gross --

A. That's the Mobil Lea State Number 2.

Q. Number 2.

A. The Number 3 is south of it. The Number 1 is east of it. And the well that offsets the dryhole, annotated "86", is the Number 4, recently completed.

Q. Okay. Well, let's look at the Number 2 and the Number 3.

A. Okay.

Q. What are the gross thicknesses of the sands?

A. Actually, in these two sands, the gross thickness is extremely close to the net porosity. The sand is very porous, so it's approximately the same.

Q. Okay. 95 or 100 or --

A. Yeah, there is actually -- Consistently in the southwest quarter of 2, there is about 20 -- between 11 and 18 feet of tight sand that occurs at the top before you hit the porosity, and approximately 10 feet in the bottom. So there's approximately 30 feet, or 25 to 30 feet, in excess of these numbers that's tight. So that would be the gross number.

Q. Okay. Now, let's go over to the Read and Stevens wells.

A. Okay.

Q. These two wells in the southeast quarter of Section 3, one of them you don't have a number by.

A. The one that's annotated "2"?

Q. Correct, the one in the northeast quarter --

A. Okay, that's the Number 8.

Q. -- of the southeast quarter.

A. That's the Number 8, yeah. Two feet of porosity in that one.

Q. What is the gross --

A. Six.

Q. -- sand thickness? Six feet gross sand?

A. That's my interpretation, yes, sir.

Q. What about the well in the southeast quarter of the southeast quarter? What is the gross?

A. I don't recall. I think it's -- But it is a very porous well, so it's similar to -- It's a little bit more than 76 feet.

Q. Okay. My question is, between your Number 2 and Number 3 wells and the Read and Stevens well in the southeast of the southeast of Section 3, and the other one, the --

A. Number 8.

Q. -- Number 8 --

A. Yes, sir.

Q. -- Well, in looking in the northeast northeast of Section 10, is there any other well control, any well control that would show a zero porosity between those wells?

A. I'm not -- Are you asking me if there are more wells out there than I have on the map? What are you asking me?

Q. I'm asking you what the basis is for showing this big nose starting in the southeast quarter of Section 3 and going down into the northeast quarter of Section 10.

A. Well, the nature of these depositional pathways are such that you're either in or out of the pathway, and it -- as -- when you map out there, you'll find that -- if you'll notice a trending across the northeast -- I mean the -- the northeast and southwest portions of Section 2, you'll see several other noses.

There are nosing trends out there with the low spots in between the noses and the low spots where the sand is, and this is consistent with almost all Delaware topography that I've mapped in the last eight years.

Q. What I'm asking is, do you have any control which would show a zero in between your wells --

A. Yes, sir, I have their well that has two feet in it, and my well right beside it has got 97 feet in it.

Q. Well, that's not quite in between, though. And there is rapid dropoff --

A. And you will notice if you'll look in the west half of Section 10, and the north -- southeast quarter of Section 3, the same thing happens. When you're in the depositional pathway, you're in the sand. And when you're out, you're out, and there's no sand. You're in a dolomite facies.

The nose is present because we have these two depositional pathways, we have two low spots. You normally have -- Unless there's one huge low spot out there, which there's not, you have a high in between them.

Q. Well, I'm looking at your map. I don't see any other nose out here.

A. Well, if you'll look in the southwest quarter of Section 2, you'll see a well that's a dryhole, annotated minus 2320. There's a nose there.

I'll point them out to you if you want me to.

Here we go, there's a nose here, there's a nose here --

MR. CARR: Mr. Boling, if you could instead of just saying "here" tell us by description where they're located?

THE WITNESS: I'm sorry, there's a nose in the southwest quarter -- southwest quarter of Section 2, there's a nose. And there's also a nose in the northeast quarter of Section 2.

Q. (By Mr. Bruce) So this nose you have on your Exhibit 7 is based solely on your structure controlling the deposition of the sand?

A. That's correct.

Q. Okay, nothing else.

What is your oil/water contact?

A. We have determined that in the third sand it is approximately -- not approximately, we believe that at 2269 there is approximately a six-foot transition zone.

A recent well drilled by Read and Stevens indicates the absolute oil/water contact appears to be 2275. For our purposes, we've used 2269 because we have several wells where we note loss of shows and change in the resistivity characteristic at that level. We're talking about a difference of six feet.

Q. Okay. And looking at your Exhibit 5, then, the Read and Stevens well, certainly in Section 10 and perhaps some of those in Section 3, are lower structurally than the Armstrong wells?

A. That's correct. And that's -- As noted on the cross-section, you'll notice how much of their sand is above the observed oil/water contact versus the amount of sand in the Armstrong well that is above the observed oil/water contact.

Q. What is the -- Looking at your wells in Section 2 and the Read and Stevens wells in Section 3, is the gravity of the oil the same?

A. Yes, sir, I believe it is.

MR. BRUCE: I don't have anything further, Mr. Chairman.

CHAIRMAN LEMAY: Thank you, Mr. Bruce.

Questions? Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. I'd like to draw back from these maps.

A. Okay.

Q. Can you give me a brief, three-line summary of the depositional history --

A. No.

Q. -- of the Delaware sand in this area?

A. No, I cannot. I can tell you this, though: The Delaware probably has no analogue in geologic history, nor possibly in modern history.

The depositional environment has been debated for years. It is in question. There are some people that believe there's a modern analogue to the Delaware Basin -- Delaware sands off the west coast of Africa, but that is currently being debated.

So I cannot do that in three lines. I may be able to do it in three hours, if you want to listen to a lecture in geology.

Q. No, I was just listening -- waiting for your interpretation.

The closest Delaware production that --

A. Eight miles to the southwest.

Q. Eight miles to the southeast? Does it have the --

A. West.

Q. -- same type of --

A. Characteristics? No.

Q. -- characteristics, with the lobes and --

A. No, the Hat Mesa field is eight miles to the southwest. This sand is in the -- The Delaware has been divided into three sections: the upper portion called the Bell Canyon, the middle section called the Cherry Canyon, the basal portion of the section called the Brushy Canyon. And we're talking about a 2500-foot section.

This sand that we're producing out of both of these reservoirs, all four of these sands in the Northeast Lea and Quail Ridge fields are in the Cherry Canyon, the last sands deposited at this particular time in the Cherry Canyon.

The wells at Hat Mesa to the southwest are primarily producing out of the Brushy Canyon, much deeper. Completely different kind of animal down there.

COMMISSIONER BAILEY: No further questions.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah. Mr. Boling, you said that the third sand is connected only downdip in the water leg --

A. Yes, sir.

Q. -- and not in the --

A. And not in the oil leg, that's correct.

Q. Okay. Now, that's based purely on your maps?

A. That's based on my maps and the engineering data that we have.

Q. You have some more data?

A. We've got a lot more data.

Q. Okay. But your interpretation is from the maps.

And then you said there was no vertical communication between the --

A. Absolutely none.

Q. Do you think -- I assume that's again inter-well. What about at the wellbore?

A. No, I don't think that there's any vertical communication -- I don't understand.

Q. Are the wells all cemented properly?

A. Oh, absolutely, absolutely.

There has been -- In fact, we're extremely careful with the cementing procedures, because there have been some casing problems out there and we have had -- experienced lost circulation. So we're extremely careful with cement.

Q. So there is support to come --

A. Absolutely.

Q. -- lack of communication at the well?

A. (Nods)

COMMISSIONER WEISS: No more questions. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Boling, just going back to your Exhibit Number 5 --

A. Okay.

Q. -- I'm curious. Do you have on top of this main producing sand --

A. Mapped?

Q. Let's see. Exhibit 5 is the --

A. -- base.

Q. -- the base of the --

A. Yes, sir.

Q. Okay.

A. Exhibit 6 is the top.

Q. Actually, my question could refer to either exhibit.

A. Okay.

Q. Do you have a regional dip on the Delaware with these sands, so many feet per mile, estimated?

A. Not really. The problem here, Mr. LeMay, is that the sands are so restricted areally to this small area, and there -- the dip is -- in the third sand, maybe up to 200 feet per mile, two degrees, but -- which is -- You know, the standard dip out here is about one degree anyway.

But regional dip is quite flat except in these depositional pathways. Apparently the edges of these incised channels must be quite abrupt, because you go from sand to nothing really -- real fast. And actually, there's probably not a thinning, as indicated on this map. I mean, you're in it and you're out of it. And you go from sand to dolomite just like that.

Q. The reason why I ask is, it looks to me like your -- and this isn't a form of criticism but just a form of exploring your style.

A. Okay.

Q. You tend to keep your contours tight and maximize structure utilizing your method of contouring?

A. Actually, it's quite the opposite. I don't utilize -- The contours are tight only because I use such a fine contour interval, ten feet.

If I used 25 feet or something -- I like to use ten feet because, you know, God is in the details. So you look for the small things out here.

And I actually try not to accentuate the structure because I'm more of a -- I like to map a big area and get a feel for the trend and then try to be consistent with the trends as I've shown here, noses and low spots, and I don't normally try to accentuate the structure.

Q. So you would say it wouldn't maximize structure, your style would --

A. No, it wouldn't.

Q. Okay. It's difficult not having regional dip to compare with your style.

A. Sure.

Q. That's why I ask the question on regional dip.

The continuity of the sands as you've mapped them --

A. Yes, sir.

Q. -- and your identification of the first, second, third and fourth sands -- It's been a while since I've even looked at the Delaware. Is that becoming standardized terminology at all?

A. No, that's mine.

The reason why I did that is because at -- Once we drilled the first well and had the discovery, had the shows in the first interval that we had along with this tremendously prolific well in this other sand, I went back and did a much more detailed map in the area and broke those sands down, because I recognized that we had two reservoirs, and at the time I thought we might have four reservoirs. So I just -- That's just a nomenclature I picked up.

And actually, if you go to the south of Section 10, down in Section 15, there are no carbonate barriers down there to these sands; you just have one big pile 400-

feet-thick sand.

So we're very close to the source. We're getting back up to -- up shelfward, and we have those carbonate barriers between the sand. It was just a convenient nomenclature for me to use while I was mapping.

Q. Final question. I assume that Charlie Read and Bob Armstrong don't go to the same church?

A. No, sir, I don't believe they do. Does Charley go to church? I don't know.

CHAIRMAN LEMAY: You want to identify those? I'm sure there would be a lot of oil, gas operators would like to know.

Any further questions of the witness? If not, he may be excused.

THE WITNESS: Thank you.

CHAIRMAN LEMAY: We can take about a fifteen-minute break here.

(Thereupon, a recess was taken at 10:23 a.m.)

(The following proceedings had at 10:41 a.m.)

CHAIRMAN LEMAY: We will continue.

Mr. Carr?

MR. CARR: At this time, we would call Mr. Bruce Stubbs.

BRUCE A. STUBBS,

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 name is Bruce Allen Stubbs.

Q. And where do you reside?

A. Roswell, New Mexico.

Q. By whom are you employed and in what capacity?

A. I'm employed by Armstrong Energy as a consulting petroleum engineer.

Q. Mr. Stubbs, have you previously testified before this Commission?

A. I have not testified before the Commission; I have testified before the Division.

Q. Could you briefly summarize your educational background and then review your work experience?

A. I'm a graduate of New Mexico State University with a bachelor of science in mechanical engineering in 1972.

Out of college I went to work for Halliburton Services, which is an oilfield service company. I worked for them for nine years, numerous locations in the Permian Basin in southeast New Mexico, primarily as an engineer.

In 1981 I went to work for Read and Stevens. I was their operations manager/engineer for approximately six years, primarily working southeast New Mexico, nonoperating properties in the Rocky Mountains and Texas.

In 1987 I went to work for Hondo Oil and Gas as the Permian Basin operations manager. I operated 1200 wells in west Texas, southeast New Mexico, and I worked for Hondo Oil and Gas up until mid-1992.

And in 1992 my partner and I started our own company called Pecos Petroleum Engineering. Since that time we've been providing service to the oil and gas industry as engineers.

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

A. Yes, I am.

Q. And are you familiar with both of the pools that are involved in the cases?

A. Yes, I am.

Q. Have you made an engineering study of these pools?

A. Yes, I've studied every well in the pools.

Q. Are the results of this engineering study contained in what has been marked for identification as Armstrong Energy Corporation Exhibit Number 10?

A. That's correct.

MR. CARR: May it please the Commission, at this time we would tender Mr. Stubbs as an expert witness in petroleum engineering.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Carr) Mr. Stubbs, let's go to Exhibit Number 10, and first I would like you to identify what is Exhibit A in Exhibit 10.

A. Exhibit A is just a short narrative of what we looked at in these fields, some of our findings and some of our conclusions.

Q. And does this basically contain your -- summarize the entire study that you have made?

A. Yes.

Q. There's an index ahead of that to all the exhibits in this book?

A. That's correct.

Q. Let's go to the portion of the exhibit marked Exhibit B -- the pages are numbered at the bottom -- and I would ask you to identify what is marked Exhibit B-1.

A. Exhibit B-1 is an enlarged view of a land plat which shows the location of the two fields. The Northeast Lea-Delaware field is outlined in orange. The Quail Ridge-Delaware Pool is outlined in red.

It also spots the wells, and later we'll use this map to identify the wells and what the production is.

To simplify things a little bit, when we talk about the West Pearl wells, they'll be located in the northeast quarter of Section 2. The Mobil Lea State wells are in the southwest quarter of Section 2. The Mark Federal wells, Read and Stevens Mark Federal wells, are in the south half of 3. The Snow Oil and Gas wells are in the southeast of 4 and the northeast of 9 and the southwest of 10. And the North Lea Federal Read and Stevens wells are in the north half of Section 10.

Q. There's a circle drawn on this map, and this circle really is not applicable to the issues involved in this case; is that right?

A. No, that's just kind of a reference to see the wells that are within one mile of the wells we're talking about.

Q. All right. Could you identify what has been marked Exhibit B-2?

A. All of the wells in the pool are listed with the operator, the well name, their location and the zones that have been perforated, and then any comments about particular wells.

Q. If we go to the second page of that exhibit, the Mobil State Number 2 is listed as being operated by Spectrum 7 Exploration. What is the status of that well?

A. That well was drilled back in 1986 by Spectrum 7 shortly after they drilled the Mobil State Number 1 well. They tested that well and, for whatever reason, it was not productive. And they have since plugged and abandoned that well. And in fact that well, that plugged wellbore, is now on the Armstrong lease.

Q. Let's now go to Exhibit Number C, the type log. How does this type log compare to the type log that was marked Exhibit Number 1 and offered by Mr. Boling?

A. This is essentially the same type log, and I have essentially the same picks as Mr. Boling has. Concerned mainly with the sands where he included the carbonate barriers, but in my analysis I'm mainly concerned with the sands.

Q. All right. Could you generally summarize the nature of the sands in each of these intervals and, in so doing, try not to just duplicate what Mr. Boling presented, but if you could briefly review each of them for the Commissioner?

A. Okay, the first sand from 5520 to 5706 is productive or potentially productive in all the wells in both fields, excluding the Mescalero Ridge Number 3, which is in Section 35, and the West Pearl Number 1, which is in the northeast northeast of Section 2. It is the main pay in the Quail Ridge field, marked Federal 1, 2, 3, 5 and 6, and the North Lea Federal 4, 5, 6, 7, 8 and 9 are completed in that first sand. The Snow Oil and Gas wells are also completed in that first sand.

Now, the discovery well, which is the Mobil State Number 1 -- it was originally drilled by Spectrum 7 and is now owned by Mid-Continent Energy, located in the northwest of the southeast of Section 2 -- that was the discovery well for the northeast Lea Field. That well is completed in the first sand and has made 76,000 barrels to date.

The first sand over both fields has produced in excess of a half a million barrels, and the daily production has been about 700 barrels a day.

We'll show in production curves in a little while that we have constant GORs, the water rates are constant. We'll show that we have an oil/water contact in the first sand that's not real definite, but at minus 2043, and that occurs in the North Lea Federal 1 Y well.

There's also evidence of that sand extending south into Sections 11, 14 and 15, so there's a large water leg associated with this oil column.

There doesn't appear to be a gas cap present. The reservoir is above bubble point, so there's no free gas.

And the oil column covers approximately 1200 acres. And if you'll look back at the map, B-1, it essentially covers the area, south half of 3, north half of 10, the southeast quarter of 4, northeast quarter of 9, southwest of 2, northeast of Section 2.

Q. All right. Let's go to the second sand. Could you generally describe the characteristics of that sand?

A. The second sand on the type log occurs from 5745 to 5840. It's been tested in three wells -- again, you might want to refer back to the map, B-1 -- in the West Pearl State Number 2, which is in the southwest of the northeast of Section 2, and also in the -- let's see, in the West Pearl 2 and the Mark Federal 5 and the Mark Federal 8, which are on the opposite side of the field. The Mark 8 is in the northeast of the southeast of 3, and the Number 5 is in the northeast of the southwest of 3.

So we have a pretty nice representation all across the field on the second sand has been tested and in all cases has been found to be wet. I think this is also confirmed by the log analysis. The resistivity of the zone is three ohms or less, and usually that means it's wet, especially with 20-percent porosity.

The only well that has produced anything out of that interval -- and it's not a sand interval; it's a limestone interval -- is the Mescalero Ridge Number 3 up in Section 35, and it's a fairly poor well. It's made 26,000 barrels of oil to date.

Q. All right. Let's go to the third sand.

A. The third sand, from 5870 to 6048, is the main pay in the Northeast Lea field. All of the Mobil Lea State wells have been completed in that third sand, and also the two West Pearl wells have been completed in that third sand.

The wells in the Quail Ridge field, the North Lea Federal 6 and 10 and the Mark Federal 4, have been completed in the third sand. Then the North Lea Federal 5 and 8 have been completed in that interval, but it's a limestone, it's changed to a limestone facies over in the east half of the southwest quarter of Section 10.

We've established an oil/water contact on the Mobil Lea State side. There's a little transition zone. It starts at about at minus 2269, water saturations increase. At minus 2275, it's basically above 60 percent considered wet.

There's no gas cap present, indicating the reservoir is undersaturated, and it's above the bubble-point pressure. There's about a two- to two-and-a-half-degree southeast dip through this third sand formation.

The third sand has produced over 234,000 barrels to date. Production is about 750 barrels a day. The zone is believed to have a strong water drive, as evidenced by constant GORs, stable bottomhole pressures, flat production rates and material balance analysis, which we'll look at here in a few minutes.

Evidence of this sand can be seen in Section 11, Section 10, Section 14, again indicating a large water leg associated with this reservoir.

The third sand covers approximately 400 acres. It covers about one-third the area of the first sand.

Q. All right. Quickly, the fourth sand?

A. The fourth sand is basically any sand we find below the third sand, and there's been two wells that have had small shows or small amounts of production. That's the North Lea 5 and the Snow Oil and Gas SCJ Federal Number 1, and it really hasn't been a significant producer in the area, and not much consideration has been given to that sand.

Q. Do the wells that are the subject of the cases before the Commission today, do those wells perform as typical Delaware wells?

A. No, back when we first started looking at this thing, it became pretty obvious pretty quick that these were not your normal Delaware oil wells.

If you'll turn to Exhibit D, D-1, what we've done is totaled all the production for all the Delaware completions in different years, starting with 1985. And 1985 is a little hard to see, so if you would turn to maybe the second one, 1986, where the gas/oil ratio -- or the gas production is overlaid with oil production.

A typical Delaware well initially starts out with a fairly low GOR. You get a flush production due to the stimulation treatment and the reservoir being at the highest pressure it's ever going to be. That bleeds off pretty quick, and you get to bubble-point pressure fairly rapidly.

You'll notice on D-2, that the gas production stays relatively high as the oil production decreases. This shows you that the GOR is increasing.

In this case, out at the end there in 1993, the GOR is about 2500 to 1. And it starts out roughly one to one. So we've reached bubble point, primarily solution gas drive. The wells after about three years flatten out to around 11 percent decline.

And this is -- If you want to glance through D-3 through D-6 real quick, it's fairly typical.

Q. You have about a year with a high decline rate that flattens out for a couple of years, and then it becomes fairly -- very flat after that?

A. Yeah, its final decline.

Q. Do you have any opinion as to what the reservoir mechanism is in the normal Delaware reservoir?

A. It's primarily a solution gas drive with maybe just a little bit of water influx in some cases.

Q. Now, Mr. Stubbs, you were a witness at the hearing last January, were you not?

A. That's correct.

Q. And when that application was denied, Armstrong was directed to accumulate some additional data on the pool; is that right?

A. That's correct.

Q. Were you involved in the May request to the Division for authority to conduct special tests on the -- I believe it's the Mobil Lea State Number 2 Well?

A. That's right, I was.

Q. And when you received that approval, was Armstrong directed to come back at the Commission hearing and present the data they had been able to accumulate on the reservoir?

A. That's correct.

Q. And are you prepared to do that at this time?

A. Yes.

MR. CARR: May it please the Commission, we are going to look at the wells individually in the pool. We're going to do that as quickly as we can.

In that regard, just as a tool to keep us all oriented as to the portion of the reservoir we're discussing, it might be helpful to pull Exhibit 2 and

Exhibit 7. Those are the net isopach maps on the two primary producing intervals.

COMMISSIONER WEISS: Before we do that, I need a little clarification. I don't see which of these curves on these six production history plots is the GOR.

THE WITNESS: There's not a GOR curve. There's gas production and oil production.

COMMISSIONER WEISS: Okay.

THE WITNESS: As the gas production stays relatively flat and the oil production drops, the GOR increases.

COMMISSIONER WEISS: It says "GOR longdash", and I can't see those.

THE WITNESS: No, there's no GOR plotted on there.

COMMISSIONER WEISS: Thank you. Which --

MR. CARR: Exhibit Number 2 and Exhibit Number 7. Those are the two net-porosity isopachs, zone 1, and the other on zone 3.

THE WITNESS: If you'll turn to Exhibit E-1, we'll quickly run through the production histories of these wells.

Q. (By Mr. Carr) First, Mr. Stubbs, we're going to do the wells that are in the Northeast Lea-Delaware Pool, correct?

A. That's correct.

Q. All right.

A. We'll start in Section 35 and go to Section 2.

Q. All right. Starting first with the Mescalero Number 3 in 35?

A. That's correct.

Q. Okay. Can you review for the Commission what is shown in regard to that well?

A. Exhibit E-1 is -- The top box is the production history of the well. If you'll -- Probably since this well is in the second sand lime equivalent, it really doesn't have a lot of bearing on the first or third sand that we'll be talking about.

But the thing we need to look at is, it behaves like a typical Delaware well: high initial rates, drops off, finally levels out. GOR starts at 400 or 500 cubic feet per barrel. Over the life of the well it's increased to 2500 cubic feet per barrel.

Q. All right. What do you have on page E-2?

A. E-2 is the raw data that we obtained from *Dwight's Energy Data*, and it's just a -- same plot. We took that data and put it in a computer program to get the GORs and blow it up a little bit where you can see it a little better.

Q. Okay. Now let's go to the wells located in

Section 2. Would you go to page E-3?

A. Okay. E-3 is the West Pearl State, located in Unit A of Section 2. This is a third sand completion. And I want to try to tie some of the production back to the geology. I think you'll see a real close correlation.

If you look on Exhibit 7, you'll notice that this well is up in that little pod in the northeast quarter of Section 2, more or less isolated by itself, not really connected to the main sand body.

And this affects, I think, the production, number one, and it also affects the GOR. We have a GOR increase from about 300 to slightly over 700 cubic feet per barrel. This indicates that there's probably, if anything, minor water influx, and it's primarily solution gas drive.

Water cuts have remained constant at about 10 percent. This well has made 24,000 barrels so it's kind of an edge well, off kind of by itself.

Q. Okay, let's go to the next well, the Pearl State Number 2.

A. West Pearl State 2 again is on the edge of the main sand body, almost into that isolated little pod on the northeast quarter. It was a third sand completion.

In the middle of 1993, they made an attempt to test the second sand. The second sand was perforated and no increase in oil production and a drastic increase in water production is evidenced by the water cut at the bottom box. In June it was about 20 percent; after the completion if was over 60 percent.

Q. Okay, Mobil State Number 1 well?

A. Okay, the Mobil State Number 1 Well is the discovery well in the Northeast Lea-Delaware field, originally drilled by Spectrum 7 and now operated by Mid-Continent Energy.

If you'll refer to Exhibit 2, that's the well that's located in the northwest of the southeast of Section 2, Unit J. It's kind of on the northeastern edge of the first sand reservoir. And it is behaving similar to what we call a typical Delaware well: High initial rate, it drops off, levels out, GOR has increased from 400 or 500 cubic feet per barrel to now slightly over 1000.

Water cuts are about 30 percent, and this well has made about 76,000 barrels out of the first sand.

Q. Let's go now to the Mobil Lea State Number 1.

A. The Mobil Lea State 1 is a third sand well, and if you'll refer to Exhibit 7 you'll see that the four Armstrong wells lay in the guts of the north-south trend of that deposit, with -- Most of them have around a hundred feet of gross interval, 60 feet above the oil/water contact.

If you would turn the page, this is the test data

on E-10 that we acquired while we were testing this well. These are daily tests, obtained from the pumper, and you'll notice that when the well was first completed back in November of 1992, there was a few days it was over 500 barrels a day.

It took a few days to get equipment --

COMMISSIONER WEISS: Which Exhibit are you on?

THE WITNESS: E-10.

COMMISSIONER WEISS: Thank you.

THE WITNESS: Once it was -- chokes were installed and the well was calmed down enough to tell what was going on, it leveled off at about 180 barrels a day. It's been produced at 180 to 300 barrels a day, and it was -- Starting in about April, it was put on about a 200-barrel-a-day production test till about mid-July.

The important things to notice here is the GORs. The middle box, GORs are initially about 300 in May.

The way they were producing it before May was, they were just allowing it to flow up the tubing. And this kept quite a bit of pressure on the well, and that evidently restricted the gas flow a little bit.

They opened the annulus in May and bled off that gas, and the GOR was stabilized at about 400 cubic feet per barrel.

Another important note is, the bottom box is the water cuts. You'll notice that the water cut initially was about ten percent, and even after the production of 200 barrels a day, the water cuts have actually decreased to less than ten percent.

So we feel like there's no coning problems in this particular reservoir, probably due to the laminated nature of the reservoir. If we do have water influx, it will probably be from the edge of the reservoir.

Q. (By Mr. Carr) All right, let's go now to page E-12.

A. I might just mention that that well in November made 3444 barrels, 114 barrels a day.

Q. Now, the E-12.

A. E-12.

Q. The Mobil Lea State Number 2.

A. Mobil Lea State Number 2. If you'll turn to E-13, this is the daily production test that we ran when that well was initially completed. The well was completed in April of 1993, and again, excellent well; we had days over 500 barrels. We finally got it choked back and calmed down to 150 barrels a day.

In June we got permission to run a 300-barrel-a-day test. Rates were increased, stabilized at 300 barrels a day.

The important things to note, again, GORs are 300 to 400 cubic feet per barrel. During the tests they leveled off just slightly over 400 cubic feet per barrel.

And again, the bottom box, water cuts. During that 300-barrel-a-day test the water cuts were less than ten percent, and there toward the end they even dropped off to as low as seven percent.

So again, even at higher rates, we're not seeing any kind of water coning or bringing water in from some other place to affect the production on this well.

Q. Now, the Mobil Lea State Number 3?

A. The Mobil Lea State Number 3 was completed in September of 1993.

COMMISSIONER WEISS: Which exhibit?

THE WITNESS: This is E-15.

COMMISSIONER WEISS: Thank you.

THE WITNESS: Another excellent well, capable of the same type of production as the 1 and 2. In November, it made 3470 barrels, which is 115 barrels a day. Water cuts about 22 or 23 percent. Gas/oil ratio is below 400 cubic feet per barrel. And this well made about 11,000 barrels.

Q. (By Mr. Carr) Now, Mr. Stubbs, have you reviewed now all of the wells in the Northeast Lea-Delaware field?

A. Well, there's one other well, and that's the Mobil Lea State Number 4. It's just been completed in the last few days. In fact, I've got a test for this morning. It's out of the third sand from 5910 to -40. First production was last Saturday, so it's been about five days now, they've been getting things on production.

This morning's test was 222 barrels of oil, 15 barrels of load water, 77 MCF of gas, fluid level at 47 joints, which would be roughly 1500 feet from surface. So there's about 3500, 3800 feet of fluid column below the producing zone.

CHAIRMAN LEMAY: Where is that well located?

THE WITNESS: That's in the southeast of the southwest of Section 2, just south of the number 1.

MR. BOLING: Offsetting a dryhole, slightly to the northwest of the dryhole.

THE WITNESS: If you will refer to Exhibit B-1 in my book, it's on that map.

CHAIRMAN LEMAY: Is that it?

MR. BOLING: Yes.

CHAIRMAN LEMAY: Got it. Thank you.

Q. (By Mr. Carr) Now, Mr. Stubbs, can you draw any conclusions about the Northeast Lea-Delaware Pool?

A. The Northeast Lea-Delaware Pool in the third sand is excellent production, probably some of the best Delaware production you're going to see in southeast New Mexico. It has a large interval, a lot of it -- a majority of it above the oil/water contact. It has the capacity to produce at high rates. We've seen no evidence of any kind of reservoir damage due to water influx, increasing GORs, damage due to fines or production rates decreasing, due to production rates.

The second sand has been tested. It's not productive, it's wet. Calculations show it to be wet, well tests show it to be wet.

The first sand has been produced in the Mobil State Number 1 in the southeast of Section 2, is the discovery well, so it's productive. We feel like it's productive all across the southwest quarter of Section 2. There's good log shows, good mud log shows. The logs calculate that this should be productive in the first sand.

Q. With the exception of the discovery well and the well in 35, are all wells in this field producing from what we call the third sand?

A. All except for the West Pearl 2, which has been perforated in the second sand, and it's -- Mostly it's all water, it's no production increase due to that workover.

Q. All right. Let's go on now, and let's take a look at oil wells in the Quail Ridge-Delaware Pool, and we will start with the Mark Federal Number 1 on page E-16. Would you briefly review the information on this well?

A. Okay, the Mark Federal Number 1 is a first sand well. It's located in Unit M of Section 3.

Noteworthy things to notice on this are the stable production. This well has been on production now 34 months. In the last few months it's averaged -- In November it averaged 190 barrels a day. It's been a top-allowable well. Again, not your typical Delaware well. The GORs have remained stable, between 300 and 400 cubic feet per barrel, and the water cuts have remained stable at slightly less than 30 percent.

Q. All right. Let's go now to E-18, the Mark Federal Number 2.

A. The Mark Federal Number 2 is also a first sand well. It's in Unit Letter N. It's the east offset to Number 1.

Again, notice the stable production. In November it made 3035 barrels. It's averaged 101 barrels a day.

One noteworthy thing: We see a slight increase in the GOR in this well. Initially, it was around 300 cubic feet per barrel, and the last seven or eight months it's come up to 400 cubic feet per barrel, and this may be an indication that we're finally getting in that one particular area down maybe to the bubble-point pressure, or close to bubble-point pressure.

Also, the water cuts have remained below ten percent in this well. It's produced 92,000 barrels to date.

Q. All right, let's go now to page E-20, the Mark Federal Number 3.

A. The Mark Federal Number 3 is another first sand well, completed February of this year. It's kind of a poor well. And it looks like, in my opinion, that maybe the stimulation treatment got in the second sand. It's had some water problems, water cuts above 60 percent. In November it made 1369 barrels. That's 45 barrels a day. And it's only cum'd about 12,000 barrels.

Q. All right, let's now go to page E-22, the Mark Federal Number 4. Would you review the information on that well?

A. This is a new well. It was -- Drilling was completed in mid-November, and the well was completed the first part of December out of the third sand. This well is located in Unit P.

The production test on December 3rd was 98 oil, 62 barrels of load water, 24 hours with 95 barrels of load left to recover. So that should be a top allowable well also. It's got about 30 or 40 feet above the oil/water contact.

Q. All right, the Mark Federal Number 5 on page E-23.

A. This well was completed in October of 1993. It didn't have any third sand. The second sand was tested. In fact, it was tested twice, two different intervals. The first interval, at 5814 to -36 was wet, 100 barrels of water per day, no show. The second interval, 5720 to -24, swab tested water. And the well was finally completed in the first sand, 5650 to 5670, for 31 barrels of oil a day, 84 barrels of load water.

If you look on Exhibit 2 -- and this well is located in Unit K -- you'll see that it's kind of on the northern edge of the first sand reservoir, so it's a little skimpy on the pay.

Q. All right, let's go to the Mark Federal Number 6, page E-24.

A. This -- Drilling was completed on this well the end of October, and it was completed in the first sand, 5652 to 5674. The test November 14th was 123 oil, 66 water, and it had a partial month of production in November and made 2536 barrels. This is, like I said, a first sand well located in Unit L of Section 3.

Q. All right, let's go to the Mark Federal Number 8, E-25.

A. Mark Federal 8 is the well located in Unit I of Section 3. It tested the fourth sand, and there was no show in that sand. It also tested the third sand and had a -- There's a low porosity part right in the top above the oil/water contact, and there's -- the sand that actually has over 15 percent porosity is below the oil/water contact. That zone tested 8 oil, 24 water, on October 30th.

An attempt was made to complete the well in the second sand, 5698 to 5727. It had a show of oil, one barrel of oil, 100 barrels of water, and that zone has since been squeezed off.

An attempt was made in the first sand, 5548 to 5572. On December 8th they were testing that well. I think since that time that zone has not been commercial, and the well is shut in, awaiting further evaluation at this point.

Q. All right. The wells we've discussed so far in Quail Ridge are operated by Read and Stevens; is that correct?

A. That's correct.

Q. Let's go now to the Snow Oil and Gas Powell Federal Number 1 on E-26.

A. Okay, this well is located in Unit P of Section 4. It's completed in the first sand. I'm going to call this a typical Delaware well. It never had a real high production at the first, but it's been fairly stable throughout its life.

The GOR started at about 400, increased to 1000, and the last couple of years the production has been so low they just haven't sold much gas off that lease. So the GOR doesn't mean much the last year or so.

Water cut has been 30 to 40 percent. The well has cum'd 43,000, 44,000 barrels. And we're probably going to call that an edge well on the western edge of the A sand.

Q. All right, let's go to Snow Oil and Gas's Federal SCJ Number 1 on page 28.

A. Okay, this well is located in Unit A of Section 9. It's completed in the first sand and the fourth sand.

Again, it's kind of a poor well. It started at 30 barrels a day, 35 barrels a day, and it's down to about 10 barrels a day now. It has some water problems. Probably out of the fourth sand it's only made 2600 oil and about 12,000 water. Water cut is about 90 percent.

Q. Mr. Stubbs, let's go now to Read and Stevens Northland Federal Number 4 on page E-30. Review this well and also review the history of the well during periods of shut-in or re-work.

A. Northland Federal Number 4 is located in Unit D. This is a south offset to the Mark Federal Number 1. This well has made 57,000 barrels. It's completed in the first sand.

It was a top-allowable well up to about January of 1993. It had a casing leak in the Seven Rivers interval, and after that casing leak there's a reduction of about 30 barrels a day in production. So now the well is making about 75 barrels a day. In November it made a total of 2266 barrels, 75 barrels of water.

GORs have been between 300 and 400 cubic feet per barrel. And since the casing leak was repaired, water production has been almost nil.

Q. In the order that was entered last February it was noted that there was no evidence that mechanical failures could result in the loss of oil and gas reserves in this pool. Is what happened to this well evidence that when there are mechanical failures, in fact, there can be a resulting loss of oil and gas?

A. I believe that's what it indicates. The well was making 100 barrels a day prior to having a casing leak. After the casing leak, it appears that it's been damaged in some way and now the production is about 30 barrels less per day.

Q. Let's go to the Lea Federal Number 5 Well and the information set forth on page E-32.

A. North Lea Federal Number 5 was initially completed in the fourth sand and third sand lime equivalent. Then in mid-1992 it was completed in the first sand interval. Since that time it's been a top-allowable well.

In November it made 3375 barrels of oil, which is 112 1/2 barrels of oil per day. This well has also had -- In fact, it's had two casing leaks. It had one casing leak in March of 1992 and another one in September of 1992. It doesn't appear that this well suffered any damage due to those casing leaks.

This well has made about 60,000 barrels to date.

Q. Move on now to the Lea Federal Number 6 on page E-34.

A. This well was initially completed in the third sand, about 70 barrels a day. In July of 1983 it was completed in the first sands. In November it made 3967 barrels; that's 132 barrels of oil per day.

It has a little bit of a water problem. There's a tracer that indicates that the stimulation treatment on the first sand frac'd down into maybe the first few feet of the second sand, and that's why you see the drastic increase in water cuts. Water cuts are now running over 60 percent, but it's still a top-allowable well, even under those conditions.

Q. Okay, let's go to the North Lea Federal Number 7 on E-36.

A. The North Lea Federal 7 tested the third sand at -- That sand is right at or below the oil/water contact.

It was wet. It was then completed in the first sand.

This well has been in production now about ten months. It has averaged 98 barrels a day over that ten-month period. In November it made 2916 barrels, and that's 97.2 barrels a day.

GORs have been 300 cubic feet per barrel or less, and the water cuts are about 50 percent. Again, there may be a little water coming from that second sand.

Q. Okay, let's look at the next well, the North Lea Federal Number 8.

A. This well was completed in March of 1993. It tested the fourth sand at 6184; it was wet. It was then completed in the third sand lime equivalent, 5934 to -60. It started out about -- almost 70 barrels -- 65 to 70 barrels a day.

In September, October, it was completed into the first sand, 5636 to -60. There was a tracer log that indicates that stimulation treatment may have been gone down into the second sand, and we see a drastic increase in water production.

November, that well made 1402 barrels of oil, 7290 barrels of water.

Q. All right, let's go to the North Lea Federal Number 9 on E-40.

A. The Number 9, located on Unit H, tested the lime barrier above the third sand from 5892 to -04, and that was found to be wet.

It was then completed in the first sand, 5610 to 5676, and this well has been a top-allowable well. It has been on production six months. It's averaged 104 barrels of oil a day during that period of time. November it made 3046 barrels, which is 101 1/2 barrels a day.

Again, GORs are less than 300 cubic foot per barrel. The water cut is about 60 to 70 percent, 65 percent.

Q. Okay, Mr. Stubbs, let's go to the last Read and Stevens well, the North Lea Federal Number 10, on page E-42.

A. Number 10 is completed in the third sand, 5910 to 5930. This well is located in Unit A of Section 10. It's cum'd 15,000 barrels since it was completed in April. Production has been fairly flat at about 70 barrels a day. In November it made 2015 barrels of oil. That's 67.2 barrels a day.

GOR -- We've seen a slight increase in the GOR from about 300 to 500. And I believe this well has a little less permeability, and it may be something in relation to that nose. It just doesn't seem to have the permeability that it should. There's 26 foot of pay above the oil-water contact in this well.

And another note that we'll talk about a little later, the North Lea Federal 10 is 2486 feet away from the closest Armstrong well, so it's scooted back to the west and to the south from the Armstrong well.

Q. All right, and the last well in these pools, the Union "A" Federal Number 2, page E-44.

A. Okay, this well is located in Unit K of Section 10. It's completed in the first sand. It's made 4000 barrels of oil, 22,000 barrels of water, and this is probably the southwest boundary of that first sand. It's a relatively poor well. In fact, it's been shut in since February of 1993.

CHAIRMAN LEMAY: Just a point of clarification, Counselor.

It looks like the North Lea Federal Number 5 and the North Lea Federal Number 10 are located in the same unit letter --

THE WITNESS: Let's see.

CHAIRMAN LEMAY: -- A, of 10-20-34.

THE WITNESS: North Lea Federal 5, that's a mistake.

CHAIRMAN LEMAY: Where is the North Lea Federal Number 5 located?

THE WITNESS: Unit letter C of Section 10.

CHAIRMAN LEMAY: Thank you.

THE WITNESS: It's in the northeast of the -- northeast of the northwest of Section 10.

Q. (By Mr. Carr) All right, Mr. Stubbs, you've reviewed the information on each of the wells in this pool. What conclusions can you draw about both of the pools?

A. The biggest thing that jumps out at us is, the sands or the zones do not produce like a typical Delaware sand. We don't have initial -- high initial production, and about a 50-percent decline in the first year.

Some of these wells now have been on production for three years, and the production has been essentially flat for that three-year period. The Mobil Lea State wells have been on production for a year now, and the production has remained flat.

This was our first clue that this is not a typical Delaware well, and there's some other mechanism taking place to keep these wells at this high production rate.

Q. Let's go now in your engineering exhibit to Exhibit F-1. Would you identify that?

A. This is a water analysis from the Mobil Lea State Number 1 Well, and we'll use this analysis in some of our calculations to determine density, chloride content, and establish a good Rw for the formation water. We'll also use this water analysis to determine the gas solubility and also on the viscosity of the formation fluids.

The thing we need to note on here is the chlorides are about 133,000, so it's fairly salty water.

Q. And the next page, F-2?

A. We determined Rw at .04 from this chart using the resistivity in the chlorides from the water analysis, and we used that to generate the water saturation chart on F-3.

Most of the logs we've looked at, we've talked about 20 percent porosity and four or five ohms. If you'll go to the column, 20 percent, and the Rt column of 4 to 5, you'll notice that the water saturations in the producing intervals range from about 40 to 45 percent. That's what we use this chart for.

Q. Now, Exhibit G, G-1 and G-2.

A. G-1 and G-2 are where we tried to determine the oil/water contacts, and it's been a little hard in the first sand. There's not a real definite oil/water contact. The best one I found was in the North Lea Federal 1 Y, which is a Morrow gas well located in the southeast quarter of Section 10.

And you can see at minus 2243 you get a break in the resistivity curve, and it goes from three or four ohms down to two ohms at that point, and we feel like that's probably a pretty good oil/water contact in that first sand.

Now, the next one, G-2, is the third sand and it sticks out like a sore thumb. This is the Mark Federal Number 4 well, and at minus 2275 you can see a drastic decrease in the resistivity from about five ohms down to about two ohms, three ohms.

So we feel pretty confident on that oil/water contact.

As we stated before, in the Mobil Lea State wells, we have a little bit of a transition zone, about five or six feet, that starts at minus 2269. But by 2275 they're the same oil/water contact.

Q. All right. Now, if you'd review Exhibits H and I together and review for the Commission your conclusions about the mobility of the fluids in this formation.

A. Since we think we have we have a water influx, we wanted to determine the efficiency of the water displacing the oil and come up with a mobility ratio.

Exhibit H-1, we wanted to determine the viscosity of the water, and in this case under reservoir conditions the viscosity is slightly over one centipoise.

In Exhibit H-2, they're the same thing for the oil, and came up with a viscosity of 1.4 centipoise.

And if you'll look at Exhibit I, this is a typical Delaware permeability -- or relative permeability curve. And then using this curve plus the viscosities, we determined -- we find that under the present saturation of about 40 to 45 percent oil saturation -- or water saturation, we have about 45 to 50 percent of the permeability, oil permeability.

Using that number, we come up with the mobility ratio of about 1.78. This means that the oil will move about two times easier through the formation as the water will, so it should be efficiently displaced by the water influx.

Q. Mr. Stubbs, let me take you back for a minute. With Exhibit G we were talking about an oil/water contact.

A. Yes, sir.

Q. Do you have an opinion concerning the potential for water coning in the reservoir?

A. We have studied now with the production tests and the high-rate tests, trying to see if there's any coning problems, and we haven't seen any coning problems. I think this is probably due to the nature of the reservoir.

As the sands, different sands were deposited, we had thin layers of shale or maybe even thin layers of limestone deposited in series, so it has a laminated nature.

And these laminations, if they're shale laminations or tight lime laminations, don't have any real permeability. So you have a reduction in vertical permeability. You have good horizontal permeability, but the fluids are not able to migrate up.

So we're not going to have a bottom water drive in this reservoir. We feel like the water is probably going to come from the edge, and in most cases from the south or southeast as indicated by Mr. Boling's maps.

Q. Okay, and you have reviewed Exhibits H and I would show that -- your study shows that the oil has a tendency to move twice as quickly or easily through the reservoir as the water?

A. That's correct.

Q. What have you observed about gas/oil ratios in the reservoir?

A. Well, as we went through the production data on these wells, we noted that the GORs on the main wells of the field have remained constant, 300 to 400 cubic feet per barrel. The edge wells, which are either farther away from the water influx or a little lower permeability, exhibit increased GORs more typical of a Delaware well, and we're not seeing water influx; they're primarily solution gas drive.

Q. Let's go now to Exhibits J and K. Could you review these for the Commission and what they're designed to show?

A. J is a gas analysis of the gas on the Mobil Lea

State 1. The main thing we want to get off this was the gravity, which is .972. It's a fairly rich gas, 1480-BTU gas.

This was used in Exhibit K to determine an oil density at reservoir conditions. Using the 38-gravity oil and the .972 gas gravity, we calculated a specific gravity of .71, and that gives us a gradient of .3112 p.s.i. per foot, and we'll use that number in a minute in some of the calculations.

Q. All right, let's move on, then, to Exhibit L, bottomhole pressure.

A. We have three good drillstem tests in the Quail Ridge North Lea area. The first one is a drillstem test on the North Lea Federal, and it tested in the third sand interval, 5891 to 5937. Final shut-in pressure was 2395, and that pressure was extrapolated to 2539, gives us a gradient of mid-zone of about .429 p.s.i. per foot. So bottomhole pressure, the third sand is going to be around 2500 pounds.

We have two DSTs in the first sand. The first one is the North Lea Federal Number 2, tested the interval 5630 to -77. Final shut-in pressure was 2347. That's a gradient of .415 p.s.i. per foot. That's not an extrapolated pressure, so that pressure would probably go ahead and build up to somewhere around that .3 gradient.

Same thing in the Mobil State Number 1, which was the discovery well. It tested 5635-5714, which is the first sand interval. Final shut-in pressure was 2328, and that's a gradient of .41 p.s.i. per foot. Again, that -- didn't have the data to extrapolate that, so we would expect it to be slightly higher than that, maybe .43 p.s.i. per foot. That's the gradient we used to determine bottomhole pressures in this reservoir.

Q. Let's move now to Armstrong's Exhibit 10-M. Would you identify and review this?

A. Exhibit M is a pressure history that we have calculated as we tested these wells. One number we need to look at before we talk about that, if you'll turn to Exhibit P -- start talking about bubble-point pressure, and from Exhibit P we determined the bubble-point pressure to be 1200 p.s.i. for the first and third sands.

Now, if you'll turn back to Exhibit M, the first batch, the data is off the Mobil Lea State 1, and the data starts in December of 1992, and the last data is in November of 1993.

This first column is the date the test was done. The next column is the casing pressure. The next column, joints to fluid level. The next column, the amount of fluid above the pump, the hydrostatic -- that column. And then the gas hydrostatic, or the hydrostatic of the gas column, calculated bottomhole pressure, and then the last column is the rate that that well was producing at that time.

Now, these are instantaneous pressures. The wells weren't allowed to build up. They were just shut down long enough to run down these bottomhole pressure gradients, or bottomhole fluid level tests to get bottomhole pressure.

If you'll recall, we determined that the bubble-point pressure was about 1200 pounds. If you'll look at the next to the last column on the right, you'll notice that at no time did we get below 1200 pounds while these wells were producing. And this is another real strong indication that the bottomhole pressure has been being maintained by water influx.

Also, one thing to notice in -- if you'll recall, we mentioned that in May of 1993, the production technique was changed, the way that they were producing the Mobil Lea State 1. It dropped down -- The oil rate stayed the same, and the pressures decreased because they were venting off or bleeding off the gas and the gas rate increased, so the bottomhole producing pressures dropped for a little while. But you'll notice they built right back up again.

Now that the wells have been pinched back to allowable, the 126 barrels a day in November, the bottomhole pressure had increased back up to over 1800 pounds.

These wells, in fact all four of these Mobil Lea State wells, are only being pumped by a time clock for a short period each day, just to keep the water off of them. If the time clock runs a little too long and gets too much hydrostatic off of the formation, these things will kick off and flow at 30 or 40 barrels an hour, just like they did back a year ago. So bottomhole pressure is still real high in the third sand reservoir.

Q. So after the tests you ran in mid-year, you've cut it back to allowable, and the reservoir has re-pressured?

A. Yes, we're seeing the higher fluid levels and higher bottomhole producing pressures.

Q. Okay. Let's go to Exhibit Number N. Could you review that?

A. Exhibit N is just an exhibit to show how productive these wells could be. We took the fluid levels back in December of 1992 and the production -- produced 283 barrels of oil that day and 36 barrels of water. The fluid level is at 48 joints, which is 1488 feet from the surface. Casing pressure was 220 pounds.

If you want the calculation, we came up with a bottomhole flowing pressure of 1837 p.s.i., and we knew that the static bottomhole pressure was originally 2539 pounds, and if we go down and calculate the productivity index we find that we produced 319 barrels of fluid with a 702-pound pressure drop. That's .45 barrels per p.s.i.

If we were able to pump that well off completely, it would produce over 1100 barrels a day fluid, and since the cut is roughly 90 percent oil and 10 percent water it would be 983 barrels of oil and 125 barrels of water a day.

Took the calculation just a little bit farther since we had a productivity index, went through the calculation to come up with the relative permeability of oil, came up with 12.7 millidarcies. And if you'll remember back to the relative permeability curve, that only about 45 percent of the total permeability is permeable to oil. That means the formation has a permeability somewhere between 25 and 30 millidarcies.

So it's -- We already knew this, we knew the well was very, very productive. This just confirms that the well is very productive, good permeability, excellent reservoir.

Q. Mr. Stubbs, could you now just identify what is contained in Armstrong Energy Corporation Exhibits O through T?

A. This is just some basic engineering numbers that we'll use in some later calculations. We've already talked about P, which is the bubble-point pressure. O is gas formation volume factors. Q is the oil formation volume factor, and that was determined to be 1.24, 400 cubic feet per barrel GOR.

R is the formation compressibility, and that was determined to be 3.7 times $10^{-5}$. Oil compressibility was determined to be 1.188 times $10^{-5}$.

Q. That's Exhibit S?

A. S. Exhibit T, water compressibility was determined to be 3.03 times $10^{-6}$.

Q. All right. What is Exhibit U?

A. Exhibit U is a volumetric analysis of the third sand reservoir, and we need a volume, reservoir volume, to do a material balance equation, which will be the next thing we do.

So we estimated the reservoir volume for the third sand, or the oil column in the reservoir of the third sand, and we used an average porosity of 20 percent or 400 acres as the area. Average height is 40 feet, water saturation of -- average water saturation of 45 percent, and oil formation volume factor of 1.24.

This calculation indicates that there's 11 million barrels of oil in place in the third sand reservoir.

Q. All right, let's go to the next page, Exhibit V.

A. This is a material balance equation for an initially undersaturated oil reservoir -- meaning that we don't have any free gas; there's no gas cap -- with an active water drive.

At this point we've pretty well proved to ourselves that we have water influx because our bottomhole pressures are staying up, we're not seeing any pressure depletion.

And we know we're above bubble-point pressure because we -- from our pressure tests we never, even during all the time we were producing the well, we've never gotten below the bubble point.

When we use this equation, we use it a couple of different ways.

The first way is in Exhibit W, and we want to determine in Exhibit W the amount of oil that would be produced if we lowered the pressure, how much -- if we lowered the pressure in the reservoir. And right now we feel like we've only lowered the pressure, maybe average pressure, about 300 pounds. And we can see from this chart that that's about -- a little over 50,000 barrels.

If we could lower the reservoir pressure farther down to the bubble point, which would be a 1300-pound reduction in bottomhole pressure, we'd see that we could produce, due to the compressibility of the system, 240,000

barrels.

Under the present, the way we're producing these wells, we're only utilizing, really, only one drive mechanism, and that's the water influx, and we're not able to take advantage of any of the compressibility or gas expansion or any of the other mechanisms available to produce the oil out of the third sand.

If you'll turn two pages to Exhibit X, we feel like this is where we're at right now, with a moderate drawdown in reservoir pressure, in this case a 300 p.s.i. drawdown.

We have produced about 56,000 barrels due to the expansion or the compressibility of the system. All the other oil, the other 178,000 barrels that we've produced, a total of 234,000 barrels to date, is going to be produced by about a 270,000-barrel water influx.

Now, if we continue -- If you'll turn to the very last page, there's a real simple diagram that kind of shows what I think is going to happen in the third sand. The blue line is the oil/water contact on the south southeast edge of the reservoir. The pink line or the red line is the facies changes in the permeability barrier to the northwest and to the north, and the wells are spotted there. The sawtooth line is the line that I envision the water front moving towards the wells. The first row of wells, like the North Lea Federal 10, the Mobil Lea State 4, are probably going to be ones that are watered out first as that front moves toward the wells.

Then the front will continue on to the upper row of wells, the 6, the 4, the 2, the Mobil Lea State 2, and then the Mobil Lea State Number 1.

What we'll have if we don't do some good reservoir management at this point in time, and we'll either lower -- find some other mechanism to produce these reserves, we're going to have oil trapped along the upper edge of this reservoir that's not going to be produced. There's no mechanism right now, there's no bottom water drive, there's no reduction of pressure to allow those floods to expand. There's no gas cap right now to allow that fluid to be pushed down to the producing well.

So we're going to actually have oil trapped at the boundary of this reservoir between the producers and the permeability pinchout. There will also be a fairly large amount of oil trapped or not moved between the wells.

Q. How can this be recovered?

A. Well, if you'll turn back to Exhibit Y, I think the first thing we need to do is systematically lower the reservoir pressure, and this will cause -- give a chance for the system to expand and let expansion of the reservoir fluids move fluid to the producing wells.

This Exhibit Y indicates that we could reduce the reservoir pressure down to 1300 pounds, which would be the bubble-point pressure. Approximately 240,000 barrels of oil would be produced due to the compressibility of the system, and any remaining reserves at that point would be due to water influx.

Now, we can take that one step further and at that point the reservoir will be evaluated, and there's two things that could be done after that.

We could either inject more fluid if the pressure was not staying up like we thought it ought to, or we could take it below bubble-point and allow gas expansion to actually expand on a forced basis and push oil toward the producing wells and possibly even build a gas cap up against a permeability pinchout. And that would displace the oil, as represented by the green shading on the last little sketch. That would push the oil downdip to the producing wells.

Q. Without this pressure drawdown and the subsequent development of a secondary gas cap, in your opinion, will the reserves that are indicated by the green-shaded area on the cartoon which is the last page in the exhibit, would those reserves be lost?

A. Yes, I'm afraid they probably would be. If we continue like we are, I think there will be about a million and a half barrels recovered from the third sand.

If we can manage this reservoir efficiently, I think there's another 600,000 barrels that could be recovered from the third sand. So that would be a total of 2.1 million barrels out of the 11 million barrels in place.

Q. And without the drawdown in pressure and the development of the secondary gas cap, then this 660,000 barrels could in fact be wasted?

A. That's right, it would be left in the ground.

Q. Now, we've been talking about the -- primarily the third sand?

A. Right.

Q. Would the statements that you've made concerning the third sand also be applicable to the first sand?

A. I think they are. If you'll recall, when we look at production curves, we've seen very stable production, low GORs, very little if any increase in GORS.

We have the same characteristics in the first sand as we do the third sand, and it indicates to me that it also has a strong water drive, and the same conditions apply.

We're going to have a ring of oil around the permeability pinchout in the first sand. And if we don't do something, and fairly soon do something, we're going to have reserves up against that permeability pinchout and in between the wells that's not going to be produced.

Q. And Mr. Stubbs, if we raise the production rate as is requested by Armstrong, will that cause the pressure to come down in the development of the secondary gas cap?

A. I believe that's correct. If you go back to Exhibit -- I believe it's Exhibit M, where we had the pressure data, when we were at 300 barrels a day we had lowered the pressure to about 1400 pounds, and that was with only two wells in the northeast Lea field and the Read and Stevens wells producing.

Now we've got three more wells, the Mark 4 and the 2, the 3 and the 4 North Lea State wells, in the Northeast Lea field now producing. So between all those wells we ought to be able to draw the reservoir pressure down to 1200 pounds.

Q. And will that have the net effect of preventing waste of hydrocarbons in this portion of the Delaware?

A. I believe it will.

It will allow the fluids in the reservoir to expand, and we'll get the benefit of that recovery mechanism, and if we decide to take it below bubble point, we'll be able to get the benefit of gas expansion and possibly even creating a gas cap.

Q. If this Application is granted, will correlative rights be protected?

A. I believe they will.

Q. And how so?

A. Well, for a number of reasons. Everybody will have the opportunity to produce their wells and manage this reservoir, and if everybody brings the pressure down equally, they ought to recover the fluid that they're entitled to from under their lease.

A couple other points. We mentioned a while ago that the North Lea Federal 10 is over 2400 feet away from the Mobil Lea State -- closest Mobil Lea State well, whereas the Mobile Lea State wells are only a few hundred feet away from the oil/water contact.

I think reason dictates that probably fluids would move from the water toward the Mobil Lea State wells, rather than oil moving 2000 feet from the Read and Stevens lease to the Armstrong lease.

Also, in the third sand there appears to be a definite nose with little porosity or little sand across that nose, and -- separating the two depositional channels. So there are really almost two separate reservoirs in the oil column connected with the big water leg to the south.

Q. Could you identify what has been marked as Armstrong Energy Corporation Exhibit Number 11?

A. Yes, that's the letter, order.

Q. Do you have a copy of that?

A. No, I don't believe I do. Yes.

Q. Is this the approval that was given to Armstrong to conduct certain tests in May of 1993?

A. That's correct.

Q. Did Armstrong then proceed, pursuant to this letter, to obtain waivers from the offset operators as required by the Division?

A. That's correct.

Q. In your opinion, has adequate data been collected and engineering analysis performed to prove the drive mechanisms involved in the reservoir?

A. Yes, they have.

Q. And in each of the zones that comprise this reservoir?

A. Yes.

Q. And have you now presented the data as required by that order to the Oil Conservation Commission?

A. Yes, I have.

Q. You are the witness who testified last January, were you not?

A. That's correct.

Q. In denying the application of Armstrong, the Division determined that evidence had not been presented on certain questions. In your opinion, has data been presented on the mechanical well failures in this area, which have resulted in loss of reserves?

A. Yes, they have.

Q. Does the available data, in your opinion, conclusively demonstrate that oil production at the proposed rate of 300 barrels of oil per day will not cause reduced ultimate recovery of oil from the third sand due to excessive expenditure of reservoir energy?

A. Yes. In fact, we need to lower the pressure to increase the recovery.

Q. Has evidence been presented on the nature and the characteristics of each of the producing intervals in the Northeast Lea-Delaware Pool?

A. Yes.

Q. In your opinion, does the evidence also demonstrate that the requested producing rate will not reduce the ultimate recovery from each of the producing zones?

A. It will not reduce the recovery. In fact, it should increase the recovery.

Q. As the Division suggested in that order, you're now requesting that both of these pools be treated as a single common source of supply and developed under one set of rules; is that correct?

A. That's correct.

Q. In your opinion, has Armstrong now responded to each of the reasons set forth in the Division's February order denying Mr. Armstrong's application?

A. Yes, we have.

Q. In your opinion, will approval of these Applications and production of the Delaware formation in accordance with the recommended 300-barrel-a-day allowable result in the recovery of oil that otherwise will not be recovered?

A. Yes, it will result in higher recoveries from this reservoir.

Q. Was Armstrong Energy Corporation Exhibit Number 10 prepared by you?

A. Yes, it was.

Q. And Exhibit 11 is the Division's May 18 letter?

A. Yes, it is.

MR. CARR: At this time, may it please the Commission, we offer into evidence Armstrong Energy Corporation Exhibits 10 and 11.

CHAIRMAN LEMAY: Without objection, Exhibits 10 and 11 will be entered into the record.

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

CHAIRMAN LEMAY: Mr. Carr.

Mr. Bruce?

MR. BRUCE: Just a few questions, Mr. Chairman.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Stubbs, you talked about typical Delaware pools. Are you aware of any other Delaware pools in New Mexico that have a strong water drive?

A. I believe the Parkway does, and probably the Paducah.

Q. Paducah?

A. Paducah. I believe the Paducah is probably one of the best Delaware -- I think it may be even a deeper zone than this, but it's excellent Delaware production.

Q. Brushy Canyon?

A. Yes.

MR. BOLING: It's actually shallower.

THE WITNESS: Is it shallower?

MR. BOLING: Yes.

THE WITNESS: Okay.

Q. (By Mr. Bruce) Does fracturing of these wells create vertical communication in the reservoir?

A. Well, yes, you usually get a vertical fracture. That's the reason you can cover -- You know, if you perforate 30 or 40 feet, you can cover that 30 or 40 feet with a fracture treatment.

Q. Have you done any calculations as to whether coning will occur in any of these wells?

A. Yes, we've looked at the coning situation, and as we stated, it doesn't appear to be a problem, mainly due to the laminated nature of this reservoir.

MR. BRUCE: Thanks, Mr. Chairman.

CHAIRMAN LEMAY: Mr. Bruce.

Mr. Carr?

MR. CARR: May it please the Commission, I omitted -- If you can believe it, I omitted a couple of questions, and with your permission, could I ask Mr. Stubbs just a couple of additional questions?

CHAIRMAN LEMAY: Certainly.

DIRECT EXAMINATION (Continued)

BY MR. CARR:

Q. Mr. Stubbs, Armstrong Energy Corporation's wells in the Northeast Lea Delaware Pool are completed in the third sand; is that correct?

A. That's correct.

Q. Is the first sand present throughout the Northeast Lea-Delaware Pool?

A. Yes, they are.

Q. Under the current allowable rates, will you be able to produce the first sand?

A. No, the productive life of the third sand at the present 107 barrels a day is going to be a number of years, 8, 10, 15 years. So it's going to be a long, long time before those reserves are recovered and the wells are available to move up to the first sand.

Q. And during this period of time, will other operators be able to produce reserves in the first sand?

A. Yes, they will. In fact, there's two operators producing on either side of the Armstrong acreage right now.

Q. And what impact does that have on Armstrong's correlative rights?

A. I think they're probably being drained.

MR. CARR: That's all I have. Thank you.

CHAIRMAN LEMAY: Mr. Carr.

Mr. Bruce?

CROSS-EXAMINATION (Continued)

BY MR. BRUCE:

Q. If I could just ask a follow-up question, what is the drainage of these wells?

A. The better wells probably drain over 40 acres. The standard proration unit is 40 acres, and based on volumetric analysis, I think you can show that some of the better wells with a higher permeability, may drain more than 40 acres, and the lesser wells may drain a little less than 40 acres.

Q. Why didn't Armstrong request an increase in the spacing if that's the case?

A. Because I think the average is going to be 40 acres, and that's a standard spacing unit.

Q. Okay. So if the average is 40 acres, then there shouldn't be any drainage of the first zone in Armstrong's wells?

A. Over a long period of time, if you're not able to compete equally, you could have drainage.

CHAIRMAN LEMAY: Thank you.

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Going back to the cartoon, the very last --

A. Yes, ma'am.

Q. -- portion, is this the scenario for the third sand --

A. Yes.

Q. -- all sands? What's --

A. Well, this is for the third sand, but the same situation would apply to the first sand, especially the wells along the permeability pinchout, because there's no mechanism now, if that reservoir pressure remains high, there's still no mechanism to produce those reserves above the last row of producing wells and the oil in between the producing wells. Same scenario would apply to the first sand.

Q. Okay, I'm trying for a correlation between this and one of the exhibits --

A. Okay, the first sand --

Q. -- like maybe Exhibit Number 7, if this is for the third sand.

A. Okay.

Q. Is there some sort of correlation between these lines --

A. Okay, the red line would be the --

MR. BOLING: Structure map would be the --

THE WITNESS: -- where the --

Q. (By Commissioner Bailey) Which --

A. -- pay goes to essentially zero. You have a zero pay. You can see this southwest-northeast trending; that would be the permeability pinchout of the northern edge, northwestern edge of the reservoir.

And the southwest -- or the southeast boundary is going to be the oil/water contact which occurs at minus 2275. And if you would -- I think Exhibit 6 is a structure map on the top of the third sand. If you would follow the contour, minus 2275, you'd see that it's a northeast-southwest trending line as we demonstrated in the cartoon.

In fact, I've sketched it in blue here. That's what it actually -- the oil/water contact would actually be, and that's represented by the blue line in the cartoon.

Q. Okay, that will help me when I further study it. Thanks.

Putting together these lobes that are showing up so strongly in the southwest of Section 2, along with this concept that you have in your cartoon, will there be areas of higher porosity through that section which will then cause a greater drainage of -- higher than the 40 acres, if that allowable is increased substantially to the point where it would then cause a decrease in the correlative rights of the wells outside of these lobes?

A. I don't believe so. You have a -- somewhat of a limiting factor, if I understand your question correctly. The wells outside the lobe have lower permeability, so they're not going to be affected as much by the drawdown in these main sands.

The main sands are also usually thicker, so you have more pay, so you have more capacity to produce too. So there's -- It's kind of balanced out, I think.

Q. I'm just trying to evaluate the impact on the lower permeability wells, for their ultimate recovery.

A. I don't think that you're going to see any impact on the lower permeability wells. They're probably not draining the 40 acres that they're in to begin with, and because there's a permeability change from the good wells to the poor wells, as that permeability decreases, the fluids are not going to move through that tighter rock very fast at all, or if it all.

Q. Right, along with the concept of the coning through the laminated --

A. Yeah, but you're talking about vertical permeability as opposed to horizontal permeability.

Q. I'll keep thinking. No questions.

A. It's two different directions. The vertical permeability --

Q. I'm well aware of that.

A. -- controls the coning, and the horizontal is the flow of the oil into the --

Q. No, I'm just putting together fracturing and your vertical permeability.

A. Well, these reservoirs are not naturally fractured. It's an induced hydraulic fracture stimulation treatment.

COMMISSIONER BAILEY: That's all I have.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, this is -- Your analysis is very interesting and very well thought out, I think. It is dependent on a lot of properties that you mention. But the production data supports your analysis.

Now, let me get clear in my mind, is this 300-barrel-a-day allowable request only for the third sand, or is that for the first sand also?

A. It's also -- It would be fieldwide. And we feel that Read and Stevens has essentially the same problem in the first sand as Armstrong has in the third sand, is they have high fluid levels, they're not able to bring the pressure down, they've got reserves they're going to have to try to manage to recover also.

The third sand is very similar to the first sand. There's the same drive mechanism, excellent permeabilities, excellent porosities. They're real close to being identical sands.

Q. And then the other question I had was, the -- any evidence to support that there's no communication between the zones at the wellbores?

A. Well, yes, I think there is, because there's been wells completed in the third sand, and they make like 50 barrels a day, say, and then you move up to the first sand and complete that, and it makes 150 barrels a day. So if they were communicated, there would have been no increase in production. So --

Q. Is that typical of most of the wells --

A. Yeah.

Q. -- that observation?

A. Yeah.

Q. And one other question. What was -- Everything else you had was documented. What was the source of the KR curves?

A. That's -- Let's see, that's Exhibit --

Q. It was I, Exhibit I.

A. Yeah, we don't have any real core data to go by out here. This is data from just my basic experience in the Delaware and some other permeability data that we have.

We know two or three things about the Delaware that helped us construct this curve.

We know that when the water saturation gets down to about 40 percent, that the Delaware will essentially produce no water. It's 100-percent permeable to oil.

We also know that when we get water saturations greater than 60 percent, that you're going to get mostly water. And if it gets toward 65 or 70 percent, the permeability to oil is zero. So that gives us a couple of starting points.

We also know that if we have 100-percent oil saturation, we're going to have 100-percent permeability to oil, and vice-versa on the water.

So we use those numbers plus just what experience I have in the Delaware to construct that curve, and it may not be exactly right because, like I say, we don't have any core data. But it's a close approximation.

COMMISSIONER WEISS: I have no other questions. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Stubbs, is 300 barrels of oil per day, the request -- is that a magic number? Or is it just kind of, the higher the number, the better, or -- How do you come up with 300 barrels a day?

A. Well, it's somewhat magic. If you'll go back to Exhibit M where we had the pressure data and the producing rates, at 300 barrels a day we got the producing bottomhole pressure down to about 1400 pounds, and that was with only two wells in the reservoir.

So to manage this thing with two additional wells on the Armstrong side and the additional Read and Stevens wells, with that 300-barrel allowable we ought to be able to get the reservoir down to the bubble-point pressure of around 1200 pounds.

But see, even at 300 barrels a day on the Mobil Lea State 2, we didn't get -- we didn't reduce the pressure to the bubble-point pressure.

So it's going to have to be a combination of all the wells in that pool to draw that pressure down.

So I think 300 barrels a day is a good number.

If we don't have 300 barrels a day, then we probably aren't going to be able to withdraw that -- you know, draw that pressure down like we need to.

Q. As that water encroaches, would the potential for coning increase with the higher deliverabilities that the wells would produce?

A. No, I don't think so, because of the -- you just -- I don't feel like you have any vertical permeability because of the laminated nature.

See, you're not going to have a bottom drive, you're not going to have classic coning where the water comes from the bottom, because there is layers of shales and limes that don't have permeability so they're going to act as barriers to the water moving from the bottom.

The water is going to come in from the side. You're going to get a -- It's going to be just like a waterflood. The water's going to move in from the side, push the oil toward the producing wells. And you're going to get this cusping effect like you do in a waterflood. Where you have a pressure sink, the oil is going to move in toward that well. And you're going to have oil in between the wells that you may not move, but it's going to be just almost like a waterflood except you're not going to have to inject water for a while, probably.

Q. Help me understand this drive mechanism a little bit more. You indicate initial bottomhole pressure was like 2400 pounds, but all of a sudden you're down to 1400 to 1800 pounds. With a water drive, why would you get that initial pressure loss?

A. Well, that's -- If you recall, we had mentioned that that was the producing pressure, and that was an instantaneous pressure while the well was producing.

So if you could imagine a pressure drawdown curve, from the edge of the reservoir would be 2500 pounds. As it approaches the wellbore, it drops off to the producing bottomhole pressure.

Now, if you were to shut that well in and allow it to build up, it would build back up to the average reservoir pressure, which you probably haven't dropped more than a few pounds.

Q. So you'd anticipate a static bottomhole pressure in the neighborhood of the initial shut-in pressures that you --

A. Yes.

Q. -- you quoted?

A. That what we're saying.

We don't think we've dropped the reservoir pressure at this point more than 300 pounds, and that's just due to the compressibility of the water column moving into the oil column. We've taken some water out of the water column, which is going to lower that pressure a little bit.

So that's where the pressure loss is coming from, is the water moving into the oil column in producing the well.

Q. Have you looked up the volumes of third sand that would be water-saturated in terms of the --

A. I've looked --

Q. -- ratio of that to the oil-saturated zones?

A. I've looked a mile and a half to the south, and that sand is still going. So there's two or three square miles of third sand down there that's pushing the water into that 400-plus acres in the oil column.

And it also gets thicker the farther south you go. Instead of having 100-foot sands, that sand grows into some pretty good-size sands.

Q. How do you visualize secondary, tertiary operations in this field? With 11 million barrels of oil in place, one would hope they could recover more than 10 or 15 percent of the oil in place.

A. Well, through the life of this reservoir it's going to require constant management, and I think the first phase is to see how we go getting the pressures down.

If everything looks good, then go below the bubble point and produce everything -- We can do a gas expansion and maybe even create a gas cap to help move those reserves.

Or at some point in time, if the water column is not able to keep up with the withdrawal, you may want to start injecting water into the ground and to go to some secondary-type operation where you're actually injecting water back into the reservoir.

Q. But at this point in time you really don't have an idea how you would go about a secondary or tertiary operation? I mean concrete -- I mean, do you have plans for that, I guess is my question?

A. Well, we have some ideas. I'm not sure you'd call them plans at this point.

You're going to have to have a decision point at some point in time to decide whether -- if you need to put more water in the ground, if your withdrawal rate is so high that the water drive is not able to keep up. All indications are now that the water drive is going to be pretty efficient.

You may just let it go and produce primary by the water influx and solution gas drive. Or you could go to a secondary and actually turn some of your wells into injectors and start putting water back in the ground.

Probably, my guess, there's going to be a tremendous amount of oil left in place. If we withdraw 2 or 2 1/2 million barrels, there's still a lot of oil in place. This would probably be a good candidate for $CO_2$-flood or some other tertiary-type flood.

Q. Are you familiar with any other orders the Division has issued concerning increased allowables in the Delaware?

A. Not in the Delaware, no.

MR. BOLING: I think there was one in --

Q. (By Chairman LeMay) There's been some. I just wondered if you were familiar.

A. No, I haven't followed that.

CHAIRMAN LEMAY: Commissioner Weiss?

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. This information you have on Exhibit M, I think your plans are quite dependent on maintaining this type of a record. Is that --

A. Yes.

Q. Is that part of your plan, to maintain this type of information?

A. On M? Yes. The pressure data?

Q. Yes.

A. Yes, definitely.

Q. So you --

A. But --

Q. -- don't get your 300 barrels a day and go home?

A. No, huh-uh, because I think everybody realizes -- at least in the Armstrong organization -- realizes that there's a lot of oil to be made here, and it needs to be efficiently managed, and everybody is aware that we're going to keep meticulous data and know what the pressures are and what the reservoir is doing.

Q. Is there enough dip here to take advantage of a secondary gas cap, such as you mentioned?

A. Yeah, there's about 2, 2 1/2 degrees of dip, which is a couple hundred feet per mile.

COMMISSIONER WEISS: I have no other questions. Thank you.

CHAIRMAN LEMAY: That's all I have.

Thank you. The witness may be excused.

MR. CARR: We have nothing further in this case.

CHAIRMAN LEMAY: Thank you. Let's take -- I need to -- I don't know if I mentioned the problem that a few of us have, I guess myself and -- We have a budget hearing at -- it's now 1:30.

So what I'd like to do, if you don't mind, is come back in about 10 or 15 minutes and break late for lunch. Maybe we can get one of your witnesses in or -- We'll see how that works.

So let's just take about a ten-minute break now, and we'll come back.

(Thereupon, a recess was taken at 12:12 p.m.)

(The following proceedings had at 12:25 p.m.)

CHAIRMAN LEMAY: We'll resume.

Mr. Bruce, your pleasure.

BILL BRADSHAW,

the witness herein, after having been first duly sworn upon his 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. My name is Bill Bradshaw. I live in the City of Roswell, New Mexico.

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

A. I'm a full-time employee as a geologist for Read and Stevens.

Q. Have you previously testified before this Commission?

A. No.

Q. Would you please outline your educational and employment background for the Commission?

A. I have a bachelor's degree in geology from the College of Worcester in Ohio. I have a master's degree in geology from West Texas State University. I'm a certified petroleum geologist through APG.

I started work in 1980 with Gulf Oil Corporation. I worked three and a half years in Hobbs, New Mexico. I worked for Texas Oil and Gas for four years in Midland and Amarillo and, most recently, the last six years with Charlie, or Mr. Read, in Roswell.

CHAIRMAN LEMAY: We all know him as Charlie.

THE WITNESS: I guess everyone knows --

Q. (By Mr. Bruce) And you've got approximately nine years' experience in New Mexico geology?

A. Yes, I have worked about nine years in New Mexico. I've been responsible for picking all of the Delaware locations for Read and Stevens that we've drilled out the Quail Ridge field.

Q. Have you testified as an expert before any other state commissions?

A. I've testified before the Texas Railroad Commission.

MR. BRUCE: Mr. Chairman, I tender the witness as an expert petroleum geologist.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Bruce) First off the bat, Mr. Bradshaw, I just want to ask you whether or not Read or Stevens is in agreement with the Armstrong request for 300 barrels of oil

per day?
A. No, we're not.
Q. You would like it to remain at just the statewide allowable?
A. Statewide allowable.
Q. Well, let's refer to Exhibit Number 1 and identify it for the Commission.
A. Okay. Might clarify, it's a little bit confusing. Exhibit D is not Exhibit D; it's Exhibit 1 if you look at the stamp. I suppose you go by that all the time.
But basically -- It's not exactly outlined on your plat, but what I wanted to point out was that Read and Stevens controls approximately 1640 acres in this area.
Q. Most of it within that heavily outlined area?
A. It's in the heavily outlined area, with the exception of the stippled acreage in the southwest -- in the west half of Section 15 of 20-34. That acreage has expired. But all of the other stippled acreage in the area is owned by Read and Stevens.
And in the past we've drilled five Morrow wells, which cost approximately $7 million, and then we have drilled 14 Delaware wells, indicated on this plat right here. We've spent approximately $6 million developing the Delaware.

Q. Now, you have --

A. That's a total of about $13 million.

Q. You have these on your legend, certain Delaware producers A through F. For ease of reference or cross-reference, Armstrong refers to the third zone. What color is that on your map?

A. That is the green sand, what I call the D sand. The top -- The A, B and C sands refer to -- Armstrong referred to those as the number one sand. I've actually broken it down into three sands.

Q. Okay.

A. And there are five productive sand intervals out there that we've indicated.

Q. Now, how many of Read and Stevens' Delaware wells have been drilled in the past year?

A. We have drilled eight wells in 1993, and we have anticipated drilling additional -- nine potential development locations in the north half of Section 3 and one well in the north half -- the north -- it would be the northwest of the southeast quarter of Section 3.

Q. What you're saying is, there's nine potential Delaware wells that Read and Stevens has in the north half of Section 3?

A. That's correct.

Q. And one final question on this exhibit. Does

Read and Stevens have an interest in Section 2?

A. Yes, we have a ten-percent working interest.

Q. Now, you just said there's been quite a bit of development over the past year. Has this development changed your view of the geology in this pool -- in this field?

A. A year ago, we had six Delaware wells, and since we have drilled the additional eight, I would say that the picture of the geology has changed out there. We can see that there's quite a bit more sand present on Armstrong's lease that is also present on our acreage in the Quail Ridge field.

Q. Okay. Let's move on to the geology. First, your Exhibit 2, the cross-section.

A. Yeah, I'd like to take the cross-section out. It sure would be easy if I could hold this thing up somehow and...

Basically, you can see -- This is a structural cross-section, and we're -- Basically, there's a map on the corner down here that shows that we're going up the east side of Read and Stevens' acreage and the Quail Ridge Delaware field, and then we're crossing over into the Northeast Lea Delaware field where Armstrong has their wells.

And what I wanted to point out first of all was that most of our production is coming from these A, B and C sands, specifically the B sand. If you look at that production index map that I gave you at first, those yellow -- the orange dots right there represent basically the B sand.

Armstrong, as you will notice, also has the B sand indicated behind pipe.

I would also point out that they have A sand and they also have C sand. And if you were to look at Mike Boling's Exhibit Number 2, which is an isopach map of the Number 1 sand interval, which is what I'm talking about, referring to right now, I'd like to point out to Mr. LeMay that the sands that he's -- He's indicating sand in the southwest quarter of Section 2. That sand could just as easily be drawn to correlate directly with sands present in the southeast quarter of Section 3.

You recall, his lower sand is trending northeast-southwest. There's no reason why these upper sands couldn't also trend in a northeast-southwest direction.

In effect, if you look at the cross-section, their wells are located on strike or updip of our acreage.

Q. And as far as their first-zone wells, you concur that that is behind pipe?

A. Yes, their zones are behind pipe. In effect, we are downdip to them, and at this time we don't feel that we're draining their upper sands.

Q. Okay, thank you.

Now, let's move on to your Exhibit 3.

A. I need to point out a couple other things.

Q. Okay.

A. On this cross-section, you'll notice this lower pinnacle right down in here. This is the Armstrong sand that is productive, and you'll notice that there's a common oil/water contact approximately minus 2275, which corresponds with what Bruce has said.

And I just want to point out that this lower sand is continuous across our acreage, it is productive in the four wells that we have, and that we are closer to the oil/water contact than the wells updip in the Armstrong acreage, and I'll point that out on some more maps.

Q. Okay, Mr. Bradshaw, now let's move on to your Exhibit 3, your -- Would you identify that for the Commission and also, where necessary, cross-reference that to Armstrong Energy's --

A. Yeah, this is a --

Q. -- isopach?

A. -- a net-porosity isopach map, and basically I've got net values of porosity greater than 16 percent over gross sand interval.

It's this exhibit right here. I don't know if you can see it or not.

Basically, it indicates the wells that are productive in green from this lower sand, the third sand that Armstrong refers to.

And I'd start out by pointing out that originally this was a -- mapped as a northeast-southwest trend, and recently Armstrong drilled their well in the northwest of the southwest quarter of Section 2, and you'll notice they have 94 feet of sand present in that well. And immediately south of there, they had 92 feet of sand. And it sets up the possibility for this re-entrant of sand, which could come down from the north, feeding into this main northeast-southwest system.

Matter of fact, Mike Boling was pointing out that the dipmeters in these wells indicated north-south deposition of sand.

We would point out that the possibility exists for additional locations in the east half of our Section 3, which could also encounter this sand.

A discrepancy that I have with Mr. Boling would be our Mark Federal Number 8, which is drilled in the northeast of the southeast quarter of Section 3. He's indicated approximately six feet of gross sand and two feet of net sand, and I indicate 62 feet of gross sand present in that wellbore, four feet of net sand.

I'd like to point it out to you on the cross-section here.

You can see the Mark Federal Number 8, from a depth of 5906 to 5996. There's sand present on the log. We've even got little bit of porosity in the bottom of it, sand that's greater than 16 percent.

We've perforated that interval. It's capable of producing eight barrels a day.

Right now the well is temporarily abandoned, but we have plans to possibly go back and produce that oil from that interval. We tried some other zones up the hole.

What I'm trying to point out is that we do have sand present on the east half of our acreage and possibly under the locations in the north half of our acreage in Section 3.

I'd also like to point out on this cross-section, well in the southeast quarter of Section 3, our Mark Federal Number 4. There's a very obvious oil/water contact at 5942 that you can see on the electric log in the Mark Federal Number 4 on the cross-section.

And I would point out that Mr. Boling, on his exhibit, points out about four or six feet of net pay that's above the oil/water contact. And our oil/water contact here would indicate that we have about 34 feet of net pay.

MR. BOLING: I'd have to concur that --

MR. BRUCE: Well --

MR. CARR: Shhh.

THE WITNESS: The point being that I'm trying to demonstrate that we have good productive pay in the Mark Federal Number 4 in the southeast quarter of Section 3.

Q. (By Mr. Bruce) Why don't you -- Okay. One thing, though, looking at your isopach, you have -- You know, going from the west half of the southeast quarter of Section 2, the Armstrong Energy wells, over toward your acreage in Section 3, there appears to be continuous sand; is that correct?

A. Yes. I'd also like to --

Q. And -- well, let --

A. Okay.

Q. Now, compare that with Mr. Boling's Exhibit 7, I believe it is --

A. Right.

Q. -- where he basically shows a big zero line running between your acreage and the Armstrong Energy acreage.

A. It's kind of a --

Q. Do you see any basis for that?

A. There is no basis in terms of -- Just looking at the isopach values, there's no indication that there's any barrier at all present. And in fact, I think his basis for saying it was there was saying that there was a little nose there at the base of the sand, and I would contend that the small structures out here don't necessarily reflect the deposition of the sand. It could have been post-depositional, it could have been post-depositional compaction, it could have been post-depositional movement. There's no isopach value indicating thinning sand between our acreage and their acreage.

Q. Now, Mr. Boling also made a statement about -- I think it's the Mark Federal Number 4 in the southeast southeast of Section Number 3 -- that it was moved to -- moved away from the thin net pay. What was the reason for moving that?

A. As indicated, as you're going over towards our lease on the cross-section, that we are becoming closer to the oil/water contact. And in order to take advantage of the structure, we moved our location from an eastward location to a more westward location in that proration unit to move updip in the reservoir.

We were not concerned about picking -- or about losing the sand to the east. We figured we would thicken in sand to the east, but we were afraid of losing structure.

Q. Do you have any other comments on your Exhibits 3 and 4 that you'd like to point out to the Commission?

A. Yes, I'd also point out on Mr. Stubbs' Exhibit Number 10, that there's no barrier indicated that would correspond with the geology that Mr. Boling in his --

Q. You're talking about his very last page of his exhibit?

A. Yes, the colored picture seems to be more in line with the geology that I have mapped in terms of the net sand presence.

Q. It doesn't show that barrier between Sections 2 and 3?

A. No, there's no barrier indicated.

Exhibit 4 demonstrates all of the potentially productive interval, Armstrong sand, above the oil/water contact. And as you can see, in our well that we drilled in the southwest of the northeast quarter of Section 10 on Exhibit 4, that well tested wet and downdip in the Armstrong sand.

Q. And you're afraid of having your wells water out?

A. Yes, we're closer to the oil/water contact when we are downdip. Structurally, this is a structure map on top of the D sand, and you can see that if you look at the Armstrong wells over in the southwest quarter of Section 2 that they are -- the majority of them are updip to our acreage --

Q. Okay.

A. -- by about 10 to 20 feet, depending on which well you choose.

Q. Were Exhibits 1 through 4 prepared by you or under your direction?

A. Yes.

Q. In your opinion, is the denial of the Armstrong Application for an increased allowable in the interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes, it is.

MR. BRUCE: Mr. Chairman, I'd move the admission of Exhibits 1 through 4.

CHAIRMAN LEMAY: Without objection, Exhibits 1 through 4 will be admitted into the record.

Mr. Carr?

MR. CARR: Mr. LeMay.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Bradshaw, to follow on the question the Commission Chairman asked earlier, you don't go to the same church as Mr. Boling, do you?

A. We live on the same street now, but he hasn't come down to help me unpack yet.

Q. Your geologic interpretation is based on well control, is it not?

A. Yes, it is.

Q. You're not integrating seismic or anything else --

A. No.

Q. -- into this interpretation?

Although we've got a lot of disagreement, are we really in agreement that there are really two primary producing zones in this area? What we call the one and the three, you call, I think, the B and the D sand, something like that. Is that a fair statement?

A. Yes, I think they're separate.

Q. And you're generally familiar with the Delaware in this area, are you not?

A. Yes.

Q. And don't we generally have a sort of southeast general depositional dip in this area?

A. Yes. Depends on which sand.

Q. Where we really get into disagreement is as to whether or not there is a nose or any kind of a barrier between your wells in Sections 3 and 10 and the Armstrong wells in 2; is that right?

A. Yes.

Q. You and Mr. Boling aren't in agreement on the gross sand interval in your -- I think it's your --

A. -- Number 8.
Q. -- Mark Federal Number 8?
A. Right.
Q. Mr. Boling found two feet of porosity. You found how many?
A. Four feet.
Q. So you're basically in agreement on the porosity; it's just the gross interval that you're not in agreement?
A. That's correct.
Q. It is possible that with additional development or information in there, you might see a nose instead of just a deterioration in the formation?
A. I'm not understanding the question.
Q. Basically what we have is just two differing geologic interpretations based on the same data points?
A. Yes, he contours it differently than I do.
Q. And he sees a nose and you don't see them?
A. That's correct.
Q. To resolve that we would have to get some additional data, wouldn't we?
A. Yes.
MR. CARR: That's all I have.
CHAIRMAN LEMAY: Mr. Carr.
Commissioner Bailey?
COMMISSIONER BAILEY: No.

CHAIRMAN LEMAY: Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. I think I wrote down that you agreed with Mr. Stubbs' cartoon, his last exhibit, basically?

A. Well, what I was basically pointing out was that they did not indicate that there was a barrier on his cartoon, whereas the geology indicated that there was a barrier.

Q. Do you think the edge of the reservoir is such as he depicted, that is, lying to the north --

A. Well, I believe it goes further to the north than he's depicted. I think that it could go in the north part of our acreage.

COMMISSIONER WEISS: Okay, thank you.

CHAIRMAN LEMAY: Are you going to have an engineering --

MR. BRUCE: Yes.

CHAIRMAN LEMAY: -- witness too?

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Talked Charlie into a well up there in the northeast of Section 3?

A. I'm sorry?

Q. Have you talked Charlie into drilling a well in the northeast of Section 3?

A. Well, he's trying to talk me into it right now. He wants to drill the northwest of the northeast of 3 right now. He's got that acreage.

I'd prefer to -- I'm a little more conservative. I step out a little bit, one well at a time. But you know Charlie.

Q. I think it's just an interpretation based on the -- The differences, I should say, are based on the presence or absence of a nose and whether that four feet or two feet indicates a termination to the north or extend it down, a kind of a tight spot between those --

A. Uh-huh.

Q. -- those wells.

A. I think that, you know, with the subsurface control, we don't have any -- There's no basis to say that it's thinning. It's purely interpretation to say that, Well, there's a nose in there, so therefore you would have less sand.

There's no evidence to indicate that the structure controlled the deposition of sand. It could be post-depositional compaction, it could be post-depositional structural movement out there. We know in general that it's a northeast-southwest trend.

Q. Do you have any objection -- or I should say, does Read and Stevens? -- do they have any objection to the consolidation of these pools?

A. I can't answer that. I don't know. I couldn't speak for my boss at this time.

Q. But you do to the allowable? You'd like to keep statewide --

A. Yes --

Q. allowable? Okay.

A. -- about our drainage.

CHAIRMAN LEMAY: Okay, that's the only question I have.

Is there anything else of the witness?

If not, he may be excused.

You may call your next witness. We might be able to get this in.

MR. BRUCE: Call Mr. Maxey to the stand.

JOHN C. MAXEY,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you lease state your full name for the record?

A. John Maxey.

Q. Where do you reside, Mr. Maxey?

A. Roswell, New Mexico.

Q. Have you previously testified before the Commission as an engineer?

A. Not *de novo*, but I have testified.

Q. Okay. You have testified before the Division?

A. Right.

Q. Okay. Who is your employer?

A. Read and Stevens, Inc.,

Q. And what is your position there?

A. Petroleum engineer.

Q. Would you briefly outline your educational and employment background?

A. I graduated with a BS in petroleum engineering in 1980, Oklahoma State.

I went to work immediately for Chevron in Midland, Texas, worked in the drilling department for Chevron for a couple of years, then went to work for Mesa Petroleum in Roswell, worked then as a drilling engineer. With Chevron, I was a drilling representative. A lot of workover/completion drilling-type of work. With Mesa Petroleum I was drilling engineer for about a year and a half.

Then moved to the Amarillo Office, the corporate office, was a petroleum engineer, working production at reservoir assignments in the Amarillo office till about

1985. Total time with Mesa was about five years.

I worked about two years for a company out of Dallas, Texas, Matador Oil Company, and was a petroleum engineer with Matador, doing drilling, production and reservoir work, and then in 1988 went to work for Read and Stevens as their petroleum engineer.

Q. And does your area of responsibility include the engineering matters related to the Quail Ridge Delaware Pool?

A. Yes, it does.

MR. BRUCE: Mr. Examiner, I would tender Mr. Maxey as an expert petroleum engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Bruce) Mr. Maxey, first, what is Exhibit 5?

A. Exhibit 5 is a letter dated December 30, 1992, that I wrote. It was to Campbell, Carr, Berge and Sheridan. It was a letter in support of an increased allowable in Armstrong's -- last year. The hearing, I believe, was in January.

Q. Do you support that application today?

A. No.

Q. Why not?

A. There's some things that have changed since the initial application, the initial hearing.

One of the things that has changed is the geology. After they drilled the Mobile Lea Number 2, it changed the geology significantly from our point of view. We felt like that initially when we supported this Application, that the D sand, what I call the D sand, this sand that they'd like to get the increase, they're providing out of, was not present on the east half of our acreage. And once they drilled the Mobile Lea 2, it became apparent that we had -- very possibly had D sand on the east half of our acreage, and therefore we did not want to incur any drainage before we had a chance to develop the acreage.

And number two, in their initial hearing they brought up some testimony indicating that there was a partial water drive, which concerned me because I was assuming we had a solution gas drive reservoir.

And those are the two major reasons that we oppose it now.

Q. Well, what is Exhibit 6 then?

A. Exhibit 6 is a letter I received -- Well, actually it came to Read and Stevens; it's addressed to the working interest owners. We are a working interest owner in the Mobil Lea State wells.

It's a letter from Bob Armstrong indicating that they were coming to this hearing to present testimony. And primarily in the second paragraph, about halfway down, there's a sentence in there that concerned me even greater, concerning what they were purporting to find in the reservoir.

It reads, "If we are not allowed to increase production to decrease pressures, a significant amount of oil will not be recovered due to the nature of the reservoir, the strong water drive, the amount of gas in solution and the extremely high bottom-hole pressures."

Number one, I disagree that we have a strong water drive. That concerned me.

Number two, I had heard this a lot from Armstrong, but no one had ever explained the engineer data, that a significant amount of oil will not be recovered due to the nature of the reservoir. I don't understand that. And after all that testimony today, I still don't understand it.

Q. Now, you have over there a copy of their Exhibit 10, their engineering study. Was today the first time you saw that study?

A. It is. I was quite surprised to see the study, being as we are a working-interest owner and we, I believe, agreed that we shared some correlative rights in the D sand. I was kind of surprised to get that today, not having a chance to put any input into it or even an opportunity to see it as working interest owner.

Q. And will you make a few comments on that at the end of your testimony?

A. I will.

Q. Let's move on to your other exhibits. First, why don't you discuss together your Exhibits 7, 8 and 9, and what do they show to you?

A. Okay, 7, 8 and 9, Exhibits 7, 8 and 9, are decline curves.

Let me briefly state, I'm just going to deal with wells that we have in the D sand and the Armstrong wells in the D sand. We've heard a lot of testimony today. In my opinion, a lot of it is not pertinent to the fact that Armstrong wants to raise the allowable in the D sand. That's what we need to be dealing with.

We have wells in other sands. Armstrong does not have any production data on any of the upper sands on their lease. Therefore we don't have anything to compare, really, as far as the performance of our wells and the performance of their wells. They're strictly producing out of the D sand.

These production decline curves, the first one is the Mobil Lea State Number 1. The reason I've entered this in as evidence, we've talked -- heard a lot of testimony today about flat GORs, and this is just a simply a decline curve on the Mobil Lea Number 1.

If you'll notice towards the bottom of the chart, there's a GOR with a line drawn through it. It's just a curve fit through those points indicating an increase in GOR.

And if you'll notice, the decline over there equals negative 100.8. The 100.8 is really of no importance, but I just wanted you to notice the negative sign in front of it. That does indicate an incline in this line.

The significance of an increase in GOR on the Mobil Lea State Number 1 indicates to me that we have a partial solution gas drive, some amount of solution gas drive. In light of all the testimony about water drive, I probably initially would have said we're dealing with a solution gas drive reservoir, but if in fact there's additional evidence to indicate water drive, we may have a partial water drive with partial solution gas drive.

Let me back up to that one real quick. I'll probably make this point later too. If in fact we have -- this is solid evidence to me we have an increasing GOR solution gas drive. If we have a water drive also that's working in this reservoir, we have simultaneous drive. Solution gas drive is the more inefficient drive. You definitely want to produce the well at a rate that will be favorable to the water drive, because that has a higher percent of oil recovery.

If you initially produce the well at a rate faster than the water encroachment and you lose a lot of your solution gas, you're going to lose a lot of your efficiency, and you're going to leave reserves in the ground.

The next decline curve is on our North Lea Number 10, and what I wanted to illustrate there was, we have just slightly increasing GOR again. I don't have a line drawn through it, but the point -- The GOR curve towards the bottom is increasing. We have flat water production. The oil is flat too, also. It's not a top-allowable well, but we're producing the well on a flat decline right now. There is no decline.

The second -- or, excuse me, the third curve is the North Lea Number 6, and if you'll notice, that the North Lea Number 6, we initially completed in the lower -- in what we call the D sand. If you can see the line I've drawn through there and the arrow at the bottom of the page, that is the point where we completed into the upper sands and commingled the well. That's why the oil, gas and water have increased after that point.

What I'm dealing with is the production before the line, which is strictly out of the D sand. We have a GOR prior to that line that increases dramatically over approximately six months, indicating we definitely have gas coming out of solution.

The water -- Something that's interesting, we talked about water encroachment and that there's no coning taking place. On this curve you can see very plainly we have increasing the water cuts.

This well is not the downdipmost well. The Number 10, which I've showed you before, is the downdipmost well, and it has flat water production.

The Number 6, which is updip, has increasing water production, and I have -- on all the frac -- well, not all the frac jobs, but a lot of frac jobs we've done, I've documented that frac height growth and propped fracture height is definitely larger than the perforated interval for all the sands.

So I believe we have coning taking place on this Number 6 well. The fact that you have vertical lamentations [*sic*] in the reservoir and there's no coning -- there's no vertical permeability, every well out there is hydraulically fractured and propped, and it destroys any of the lamentation [*sic*] or the effects you get from lamentation [*sic*]. There's an order or magnitude of vertical permeability that's much greater than horizontal.

Q. Now, based on this, what would you suggest is necessary to find out what rate this field should be produced at?

A. What's necessary, especially under -- When you're under simultaneous drive, that's my big concern, that's why I'm here. If in fact we have simultaneous drive, an MER needs to be established for the wells and for the field.

An MER is a maximum efficient rate of recovery. An MER takes into account the amount of water influx you have into the reservoir. And once that is established, you'll know much better at what rates to produce your well so you can take advantage of the water drive and the more efficient displacement of the water drive, rather than depleting your gas and allowing it to expand and producing it at higher GORs.

Q. What type of data would you want for an MER calculation?

A. MER calculations are primarily a material balance calculation. And what -- The critical information you need is PVT data, accurate bottomhole pressure data and enough ultimate production to plug into your equations.

In this case, we probably have enough ultimate. Normally five to ten percent -- Well, I take that back. I just thought of something. In most cases -- or the average, I guess you could say -- you need five to ten percent of your ultimate production, you need to produce that and have accurate records, with accurate bottomhole pressure data and PVT data to, in turn, do a material balance and try to establish how much water influx you have.

In all of Armstrong's testimony, they talk about the bottomhole pressure. They have not taken, that I know of, one single bottomhole pressure point. They have used a DST off of our well on their initial point. Every other pressure point they've taken has been a surface buildup using -- or excuse me, not a surface buildup but a fluid level shot, using casing pressure and then calculating the bottomhole pressure based on gradients of fluid in the wellbore that are not known at the time. You're just estimating what those gradients are.

I looked at some of the bottomhole pressures in their report. On, I believe it's the Mobil Lea Number 1, they had a constant rate, and they calculate -- They shot a lot of fluid levels over the months. The bottomhole flowing pressure that they calculated was fluctuating quite a bit at a constant rate. To me, that's indicative of the error that you can bring about in doing that. But those -- that's the --

Q. Okay.

A. Yes, sir.

Q. Let's move on to your Exhibit 10. Identify it and briefly set forth what this shows you.

A. These are GORs, initial and late GORs that I have on three of the Mobil Lea wells, two of our wells. The Mark Federal Number 4, I don't have adequate information to have a GOR prepared at this time.

These are initial GORs that I calculated using two months of production very early in the life of the well when it initially came on. And then the latest GOR represents November, 1993, production information, with the exception of the North Lea Number 6. It was in May of 1993. That was the last month we produced it prior to recompleting and commingling with other sands.

What this exhibit will show you is that, clearly, on the Mobile Lea Number 1 and 2 and 3, on the initial GORs, as each well was drilled, the initial GOR, which is the critical one -- if you want to measure -- If you want to try to measure all this at surface, your initial GOR is the most critical. That's representative of your solution gas/oil ratio that you have in the reservoir at the time you start producing.

The Mobil Lea Number 1 was 280 MCF -- excuse me, cubic feet per barrel of oil. Now, if you were going to move over and drill an offset and you had a strong water drive that was keeping pressure maintenance on your reservoir, and you weren't having any gas come out of solution and you were having flat GORs, you would expect the same GOR at the next location.

The Mobil Lea Number 2 that as drilled four months later had an initial GOR of 360 cubic feet per barrel of oil.

Moving on with the Mobil Lea Number 3, the initial GOR is up to 395 now, when it was drilled.

So we have an increase in GORs. It's not a large increase, but we're not talking about very much production either. I think it's a clear upward trend indicating there's a solution gas drive taking place in this reservoir.

I think that this data is conclusive testimony that you need to be very careful. If you suppose that there's a water drive, if you have any feeling there's a water drive, then you have simultaneous drive taking place. You'd better be careful with the amount of oil that you produce from your wells, because if you produce at a rate higher than what the water influx is, you're going to be damaging your ultimate recovery.

The North Lea Number -- Fed 6 and North Lea Fed 10 are just a further indication. They are down in Section 10 on our acreage. I saw the same thing on our wells, once we drilled those. Two months apart, the GOR initially on the Number 6 was 195, and on the Number 10 it was 283.

So I see expansion taking place outside the 40-acre drainage radius.

The North Lea Federal Number 6 was not what we call a top-allowable well. There was testimony earlier that top allowable -- or, excuse me, wells that aren't real good wells, less than top allowable, probably don't drain up to 40 acres, they drain less than 40 acres. This, to me, is clear evidence that drainage is taking place on a larger spacing than 40 acres on all the wells.

Q. Let's move on to your Exhibits 11 and 12. Would you discuss them for the Commissioners?

A. Oh, can I back up, just --

Q. Sure.

A. Okay, I just wanted to make one more point.

The latest GOR, you'll notice that the latest GOR on that exhibit is also increased from the initial GOR. That also indicates you've got solution gas drive. I mean, you've got gas coming out of solution, your GOR is going up.

The other one is the Mobil Lea Number 3, because that's the newest well, and the GOR is essentially the same month for initial and latest.

Q. You're looking at the third and fourth columns there; is that correct?

A. Yes, that's right.

There was also some testimony that a 300 to 700 GOR over a ten-month period was a minor sign of water influx.

If that's the case, our North Lea Number 10, we've got a GOR increase of about 300 over about a six-month period. That would indicate to me, based on that testimony, there's only minor water influx, that the majority of this production is solution gas drive.

Q. Okay, please move on to your next exhibits, the next two exhibits.

A. As stated earlier, the Mark Number 4, I didn't have adequate data for GORs, but I do have individual well tests that I wanted to introduce as evidence. On the Mark 4, this is a 48-hour test.

You'll notice that in the upper left-hand corner on both pages, the oil produced on the test was 106 barrels the first day, 114 the second day. Top-allowable well.

You'll also notice that about midway down, kind of on the left, under the heading, "pump", did the well pump off? Yes. We're producing that well at top allowable rate, but that is the maximum we can get. If we're forced into a competitive situation with the four wells just across the lease line and triple their production, we lose, period. There's no -- There's no way around it.

Q. And finally, what do your Exhibits 13 and 14 show?

A. Well, I threw this in there. There has been some testimony that we're producing from the upper sand and that Armstrong is going to have to wait until the lower sand is depleted before they actually produce their upper sands.

Well, you'll -- As you have a chance study this, you can see that clearly we have wells producing more than the top allowable. Some of those wells are commingling. In other words, we've got more than one sand open, and they're producing at a top-allowable rate. They could in fact produce more.

We're not interested in an allowable increase at this time because we haven't even delineated the reservoir yet, we don't even know the extent of the reservoir. I'll get into that later in their study. They used volumetrics. They plugged in 11 million barrels of primary recovery -- or, not primary recovery but ultimate recovery -- I'm sorry, it's ultimate recovery; it's in place. 11 million barrels a day, barrels of oil in place in the reservoir.

Well, they used 400 acres for the reservoir volume. We have no dryholes except for probably our well, the Number 8, which delineates a very small portion of that reservoir. Volumetrically, that reservoir may have 30 million barrels, I don't know. There's no limit on it yet.

But these wells show you that we are producing from more than one zone and that Armstrong has the same capability. They can set a bridge plug over their perforations, they can produce -- test and produce their upper sands, and they can commingle them with the lower.

Yes, the well will produce a lot more than the allowable, but at least you've got everything on line. As is bottomhole pressure draws down, you'll get more and more production from the sand that maybe is the poorer sand, but over time you'll deplete the sand.

If we all operate under the same allowable and they're not given an unfair advantage because we don't have wells that can do that good, there's no correlative rights to be impaired.

Q. Is Read and Stevens concerned about its downdip wells being watered out?

A. Yes, we are. If -- When we're talking about a strong water drive, which -- I guess you would probably surmise that I don't agree with that, but if you were to present testimony that there's a strong water drive, yes, the downdip wells are going to be the ones that suffer, they're going to be the ones that water out first, especially if you have wells updip that can produce at a much higher rate. The downdip wells will suffer. They'll be the first to water out. Unfortunately, those are the ones on our acreage.

Q. Let's move on to Armstrong's Exhibit 10. Generally, do you agree with the conclusions?

A. No, I don't. There was a lot of work going into this, and unfortunately we didn't have any input on it. We didn't have the opportunity to have any input.

I disagree with the conclusions. Some of it I agree with, and some of it I don't. But like I said, it was a lot of work.

Q. Would you please pick out the two or three things you disagree with most and state why you disagree with them?

A. Okay, there were a lot of things that I probably could pick out. Some of them may be small, not have that much impact on our case. We could probably be here all day arguing about it. I think -- I'll try to run through here, because I made penciled notes and, like I said, this is quite a bit to digest that quickly.

There was a comment, no gas cap is present, indicating the reservoir is undersaturated and above bubble point. We have not drilled the updip limit of this reservoir. That's where your gas cap is going to be located. If in fact there is a gas cap, it may not have been drilled, simply because we haven't delineated the updip point of this reservoir.

Furthermore, in the Delaware -- I have no engineering data to back this up, but I really feel like gravity segregation probably will not be a big factor in this reservoir, as far as gas migrating. Once the well is produced, gas breaks out of solution. I don't think gravity segregation will have a big impact till the gas actually migrates updip.

Now, if it does, that's a whole 'nother study and you've got to understand that drive mechanism too, because then you have three drives working. You've got water drive, gas cap and solution gas. And if you want to order those in terms of efficiency, gas -- excuse me, water drive is the most efficient, so you want to take advantage of that as long as you can. And when you can't take advantage of that, you want to structure your reservoir management to take care of your -- to produce by gas cap drive, because that is the next most efficient. And then finally solution gas is your most inefficient, but that's your remaining energy source.

Moving along -- Oh, on page A-3 there was a -- again, there's evidence that a strong water drive is present. I'm not convinced there's a strong water drive. I believe that in order to determine if there's a strong water drive, your material balance has to be backed up with good PVT data, good bottomhole pressure data, and of course we do have some good production data that we could plug in.

If we don't plug in the right size as far as the volumetric -- the oil in place -- that gets back to the size of the reservoir -- all these calculations are -- they're not going to be worthwhile, because we don't know the size of the reservoir. It's just -- It will be in error.

Again, if we had -- I could make a -- I could probably make a -- infer some kind of judgment on this report if all the bottomhole pressures were -- or, excuse me, the calculated bottomhole pressures, if they were actually bottomhole pressure buildups or some kind of a bottom mechanical recording device, if the pressure appeared not to decline, the initial pressure had not declined any at all, I would be able to look at this in five minutes and say, yeah, I believe you're right, we have a water drive.

But I will not -- and because I've had the problem on our wells of shooting fluid levels and trying to determine accurate levels, I don't use that data for anything of any weight as far as calculations.

Armstrong has told me -- we've talked about this -- they did mention they shut their casing in, allowed head to build up and hold the fluid down. You still don't know the density of the fluid that's in the casing that you're calculating with, and you still don't know if there's a slug movement in the casing. There's no way to tell.

One of the other points -- I may need to move along here, but we attribute this to the laminated nature of the Delaware with thin shale beds dispersed throughout the sand body and creating barriers to vertical permeability.

As I stated before, vertical permeability, the barrier effect you get from the laminations in the immediate vicinity of the wellbore is destroyed by vertical fracturing, and coning is an ever-present possibility from bottom water. If you have very, very high conductivity from bottom water up to your producing zone, if in fact it's a drive mechanism -- I don't believe we've still established that, but if it is a drive mechanism, you could cone the water up through a vertical fracture.

It could take place at any time. And there would need to be some calculations to figure out, even though you didn't have coning with 300 barrels of water a day for six months, the next month the coning -- you may see the water head. You need to know where that's going to happen and if the rate's excessive.

I think the rate -- 300 barrels a day is excessive on several points. One of them is the coning, one of them is the drive mechanisms. We don't have a handle on them, and there's a great possibility -- Well, I believe in my mind a hundred percent, if the allowable is increased that you stand a very, very high chance of leaving ultimates in the ground because you don't know what kind of drive mechanisms have taken place and what percentage each mechanism contributes to the total production of the well.

Q. Any other major points?

A. I think that's -- Well, the constant GOR with water, I disagree with that.

Material balance, I've already stated that's incorrect because we -- unless everybody else goes out and drills dryholes right around our producing wells to go ahead and delineate a 400-acre reservoir. But the reservoir could be 800 acres. That could be off by a factor of two.

Q. There's no well control to the immediate north and northwest?

A. There's no well control to the north. There's -- I believe -- I was talking to Bill; we have well control on in the next section to indicate the sand is not there. That leaves the whole north half of their section open, and our geology would indicate on the northeast part of our section, very possible that the sand develops.

Q. Were Exhibits 5 through 14 prepared by you or under your direction or compiled from company records?

A. Yes.

Q. And in your opinion is the denial of the Application to increase the allowable in the interests of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes.

MR. BRUCE: Mr. Chairman, I move the admission of Read and Stevens Exhibits 5 through 14.

CHAIRMAN LEMAY: Without objection, Exhibits 5 through 14 will be admitted into the record.

Mr. Carr?

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Maxey, when you look at data on the reservoir, I gather you're seeing an increase in gas/oil ratios?

A. Yes.

Q. Based on the amount of time you've had to look at Armstrong's Exhibit Number 10, have you found anything in that exhibit which would suggest that any of the raw data on gas/oil ratio is in fact incorrect?

A. In the time that I've had to look at it, no. And in fact, there were some flat GORs, there were some increasing GORs.

I'd like to comment that -- furthermore, that the flat GORs is not indicative of water drive. Flat GOR -- You can have a hundred-percent solution gas drive reservoir. If you're above the bubble point, you're going to produce that reservoir at a constant GOR, and there doesn't have to be any water influx whatsoever until you reach the bubble point, and then the GORs increase.

Q. All right, are you --

A. So that's not conclusive of water --

Q. Are you suggesting that in this reservoir we're above the bubble point and that's why the GOR is flat?

A. I believe that -- Yeah, I concur that we're above the bubble point. I think there's a -- I have a -- I believe the bubble point is lower than -- I believe it's about 800 to 900 p.s.i.

Q. And we're producing at pressures above that?

A. Right.

Q. If we look at your Exhibit Number 7, the data that you've used to project GOR in that exhibit runs through some time in 1993, does it not?

A. The GOR --

Q. Yes.

A. -- data? Yeah, it runs through late 1993.

Q. If we look at the actual data, in fact, September, October and November, they were flat, were they not?

A. No, the last point is actually up from the two prior.

A. Have you looked at the actual data points that have shown in Exhibit 10 presented by Armstrong on page E-9?

A. Run that by me again. E-10?

Q. Doesn't it appear on this well that actually the gas/oil ratio has flattened out?

A. Wait, I've got two different things here. E-9? Okay. On the last three?

Q. Yes.

A. No.

Q. Yes.

A. No is my answer. The furthest one to the left, the third one to the left, it's lower than the last two. So if you did a least-squares fit on that, you'd have an increase in GOR.

Q. So you'd still, based on that well information, show a gas/oil ratio increase like you are depicting on your Exhibit Number 7?

A. I don't know if it would be exactly like I'm depicting, but I'm just saying that there is a slight increase there.

Q. What we're talking about is gas/oil ratios that go into the range of -- from your Exhibit Number 10, a range of about 386 to 504; isn't that right?

A. Yeah.

Q. Aren't those still relatively low for solution gas drive Delaware reservoirs?

A. Each reservoir is different, so -- This is a particular reservoir, so I don't know if they're actually low for this reservoir or not.

I do know that the trend is upward and that GOR is not necessarily a function of rate. So even if you're jockeying the rate around, if the GOR goes up you're having more gas come out of solution.

Q. If I understand your concern, you're concerned about drainage -- four wells on Armstrong's side, competing with your wells off to the west.

A. Well, there's several factors.

Q. Is that one of them?

A. That would be one of them. They're -- I think I illustrated that we're draining more than 40 acres, so you're going to be in a competitive situation.

If you want to raise the allowables above the statewide, and we don't have anything that will do that as far as this D sand, the offset well, we're put at an unfair advantage.

Q. How far apart are those wells?

A. Well, they're offset proration units. I don't know the exact footage. But it's 40-acre proration units, so...

Q. Two thousand feet, maybe?

A. I guess that's possible, I'm not sure. I'd have to scale it off on the map. I don't know the answer to your question.

Q. Okay. You're also concerned about watering out your wells; isn't that right?

A. If we have a water drive like they're suggesting, I'm concerned about it.

Q. And aren't we really concerned about a problem that would develop between the Armstrong wells in Section 2 and the Read and Stevens properties in Sections 3 and 10?

A. I'm not concerned -- I put a lot of faith in our interpretation. I just don't -- There's no control for what they testified on that permeability barrier.

Q. But what we're saying is, a problem that will develop by drainage towards Section 2 from the Read and Stevens properties, isn't that what you're concerned about?

A. Well, possibly drainage if we're talking about pure solution gas drive.

Q. And what else?

A. If we're talking about water drive, watering out.

Q. Wouldn't it be because of the effect that occurs across that line between Section 2 and your properties to the west?

A. Restate the question if you can.

Q. I'm just trying to identify where our problem is in the reservoir. You seem to be concerned about a higher allowable that would be produced by Armstrong wells in Section 2; is that right?

A. Right.

Q. And that would then have an impact on your wells in Sections 3 and 10?

A. It would have an impact on all the wells.

Q. It would cause the water to move to your wells more quickly, you're concerned about that?

A. It would cause the water to move to our wells more quickly, and it would cause -- If we produce faster than the water encroachment we're producing under solution gas drive in part of the reservoir, and that's more inefficient than allowing the water to displace the oil.

Q. And you're basing your engineering determinations on whether or not there exists a nose or a barrier in that area, and you're concluding there is not evidence that shows that?

A. Right.

Q. Now --

A. Now, I'd like to state, though, that that barrier, it doesn't necessarily -- If you talk about a barrier there, we have no conclusive evidence it's there.

Number two, if it is, we don't know what kind of barrier.

Number three, it doesn't have to be a very permeable sand, but it can be a pressure -- it can have pressure communication, which would affect both sides.

Q. Now, you're familiar with your Mark Federal Number 4 well, are you not?

A. Yes.

Q. How many feet of pay do you have above the oil/water contact in that well? Do you know, approximately?

A. I would have to glance at the cross-section real quick.

Q. Approximately 34? Does that seem about right?

A. Yeah.

Q. If you go off to the east, to the Mobil Lea State Number 3, do you know how many feet they might have above the oil/water contact?

A. I believe they have more above the oil/water contact.

Q. Do you want to look at the cross-section?

CHAIRMAN LEMAY: Counselor, could I break it here?

MR. CARR: Yes.

CHAIRMAN LEMAY: Why don't you come back after lunch and --

MR. CARR: All right.

CHAIRMAN LEMAY: -- pick up? I normally don't do that, I apologize. But I have to be there in --

MR. CARR: No, I understand. Thank you.

CHAIRMAN LEMAY: -- three or four minutes, so we'll break and come back at 2:30.

(Thereupon, a recess was taken at 1:25 p.m.)

(The following proceedings had at 3:30 p.m.)

CHAIRMAN LEMAY: We're back in session. I apologize for the delay. It's beyond my control, as they say.

Mr. Carr, you may continue.

Q. (By Mr. Carr) May it please the Commission.

Mr. Maxey, when we recessed, I was asking you some questions about the -- your testimony concerning the impact producing four wells, Armstrong's four wells in Section 2, could have on the pool as a whole and, in particular, on Read and Stevens properties off to the west of there.

I had asked you about the Mark Federal Number 4 well and asked you if in fact it didn't have 34 feet above the oil/water contact, and I believe you had agreed with me at that time.

I asked you if you could then determine how many feet there were in the Mobil Lea State Number 3 well above the oil/water contact. Have you had an opportunity to check?

A. Oh, no, I'm sorry.

Q. Can we get the cross-section and have you look at that? Anybody's cross-section?

A. Twenty-six feet on this cross-section. I think ours may be -- Is ours 26 feet?

MR. BRADSHAW: Pardon me?

THE WITNESS: On the Mobil Lea Number 3, how much water -- I mean oil -- above the oil/water contact?

MR. BRADSHAW: I don't have it on my cross-section.

THE WITNESS: Oh, okay.

Q. (By Mr. Carr) Subject to subsequent check --

A. Right.

Q. -- if there are 26 feet in the Mobile Lea State Number 3, then in your well there would be 34 feet above the oil/water contact.

How much of the time are you producing your well, the Mark Federal Number 4? Is it on basically all the time?

A. Yes.

Q. And at what producing rate? What is your producing rate on that?

A. It's at top-allowable rate.

Q. Okay. Would it be making 107, then, approximately, a day?

A. Approximately.

Q. Now, if we go to the Mobil Lea State well, assume for purposes -- you can check this later -- for the question that it's on about half the time to make the 107-barrel-a-day.

Can you explain to me what would cause this difference in producing characteristics between these two wells if in fact there isn't something in the reservoir separating them?

A. It could be the permeability of the sand. I think we've basically got the same kind of frac that we're putting on them, so I believe like there's a -- They have a thicker section that looks better on the logs, and that's probably got better permeability.

Q. It's not a completion technique?

A. I don't believe so.

Q. Could it be because there is some sort of a restriction between the two?

A. I don't believe so.

Q. You wouldn't think this might be evidence of that?

A. No.

Q. You testified --

A. Usually -- I was just going to say, that's a characteristic of the sand face there at the wellbore.

Q. You testified that you had certain wells -- I believe you testified you had certain wells that could do better than the current allowable; is that right?

A. Yes.

Q. So how many of your wells are you actually cutting back?

A. I believe we've got about -- I'd have to look at the well tests for sure, but I believe we've got three that will not produce at top allowable, so --

Q. And the rest would?

A. Primarily, yeah, the rest would.

Q. And so if the allowable is increased, would Read and Stevens go ahead and produce at the higher rate?

A. I don't know. If there is some sort of a water drive, if we were to increase the rate above the MER, we would be losing ultimate reserves, so I don't know if we would or not.

Q. These are on sliding-scale royalty leases, are they not?

A. Right.

Q. That isn't a factor, is it, in the rate at which you produce the well?

A. Not really, because if you go from a hundred barrels a day to 300, Read and Stevens' bottom line is probably impacted negatively by about six or eight percent.

Q. You said a couple of times that what we really need is to determine a maximum efficient rate, an MER, for the reservoir; is that correct?

A. Yeah -- Say that again?

Q. Haven't you testified that what really is needed here --

A. Yeah.

Q. -- is the determination of an MER --

A. Well --

Q. -- for this reservoir?

A. -- I believe if there is a water drive, that an MER -- Yeah, we should determine some type of rate of withdrawal from the reservoir, and it should be based on whether the dominant drive -- if we should take advantage of the water influx or, if it's not fast enough, then maybe we have to take advantage of solution gas drive.

Q. To determine what that would be, you would need to run material balance calculations; isn't that correct?

A. Right. You would need to -- Number one, you would need to have some accurate bottomhole pressure data.

Number 2, I believe you would want some accurate PVT data.

You could get everything from text correlations. It's not as accurate as actual measurements.

Q. You could get that bottomhole pressure data and that PVT data if you needed it, could you not?

A. I believe so, yeah. The fact that Armstrong's wells are flowing is -- Normally on a pumping well that's kind of difficult to get. If we had some flowing wells it would be a lot easier to get bottomhole pressure data.

Q. Now, during this past year no effort has been made by Read and Stevens to determine what a maximum efficient rate would be for the reservoir?

A. No, we've just been producing at the statewide allowable.

Q. And if we needed to establish that, how long would that take to obtain that kind of information?

A. I -- That's difficult to say, but you have to start at this point forward with some bottomhole pressure information.

Q. Could you do it in two years' time?

A. Yeah, I believe you could do it in two years.

I believe what it would be a function of is how much ultimate -- or how much more recovery you have from this point forward. Do you need a certain amount of recovery? And I think I earlier stated -- Now, this is initially, you would want to make five or ten percent of your ultimate at least to do material balance. You may have to do that again from this point forward and have your PVT data and your bottomhole pressure data.

Q. Now, Armstrong has during the past year studied the reservoir and determined and testified that continued production at 107 barrels a day could cause reservoir waste.

Do you have any evidence that would show that continuing to produce at that rate will not cause waste?

A. Just reservoir textbooks. I mean, I don't have any reservoir textbook that would indicate producing at any rate, lower rate than a higher rate, will lose reserves.

Normally -- and you can read in *Frick* or *Craft and Hawkins* or *Slider* -- conservation of energy in the reservoir is the main factor for increasing ultimate recovery. To open the wells up, you have a good chance of losing your ultimate.

Q. To date, though, during this last year you haven't done any independent studies to determine what the best rate would be?

A. The MER, no, I have not.

MR. CARR: Thank you. That's all I have, thank you.

CHAIRMAN LEMAY: Thank you.

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Mr. Carr was touching on some of the questions I had. One of the factors on the MER was knowing the ultimate production, but you can't get that factor until you know the limits of the reservoir; is that correct?

A. Right. Well, using the -- What I was touching there was, using the volumetric calculation for your oil in place, to do the volumetric calculation, to figure out how much oil you have in place in the reservoir, you have to have the size of the reservoir.

Q. And --

A. We have not delineated the reservoir. Armstrong has four top-allowable wells. There's no dry holes surrounding them. We don't know if that sand is going to pinch out on the next location or if it may pinch out in the next section.

So the calculation of the 11 million barrels of oil in place is just estimating the reservoir truncates around the existing production.

Ultimate production -- Once you delineate the reservoir, if it's three times as large, the ultimates may be -- or excuse me, the oil in place may be 33 million barrels instead of 11 million barrels. And that goes into a material balance calculation.

Q. Which leads up to my question of what efforts is Read and Stevens undertaking to delineate the reservoir boundaries? What is their drilling program?

A. Well, we've drilled 14 wells so far. We have another well staked in the north half of the section. That -- Well, the last four wells we drilled have all been stepouts, moving away from existing production.

That's what you have to do to delineate. As you move to the edge of the reservoir, you finally drill a dry hole or a marginal well, and that's how you delineate how big your reservoir is.

And we've drilled -- The last four wells we drilled were all step-out wells. The next well that we are staking right now is in fact two locations away from our existing production. That, in fact, could -- may be a dry hole, I don't know. If it is, that will help us as far as determining what our northernmost limits are on the reservoir.

Q. And when did you expect to spud this well?

A. We have all the regulatory -- federal regulatory processes going on right now. We're trying to get the well approved. So we're probably looking at some time in

February, spudding the well.

Q. Is there any increase in production limits that you would consider fair and reasonable at this point?

A. We had discussed that. I discussed it with Charlie Read, the owner of our company, and he indicated to me he would agree to a 150-barrel-a-day allowable increase. I advised him we had no engineering data to support that as being, you know, a good rate. It could be over the MER. I don't know. The state allowable may be over the MER.

I suspect that we're not keeping -- that we're withdrawing oil from the reservoir faster than the water is encroaching now because of some of the increasing GORs.

But anyway, he's the boss, and so -- we have considered that and talked to Armstrong about it, even mentioned maybe 150 barrels a day.

But like I say, I don't have any engineering data to support that.

COMMISSIONER BAILEY: Okay, those are all my questions.

CHAIRMAN LEMAY: Thank you, Commissioner Bailey.

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yes, sir, Mr. Maxey. Did I hear you earlier to say that you estimate the bubble-point pressure to be 800 to 900?

A. Yeah, you're just using the standing correlation. All I about did was used a 300 GOR. I think Armstrong used a 400. So that's the difference in the correlation. It's a pretty big difference, though.

Q. How does Read and Stevens measure bottomhole pressures?

A. We've tried to shoot fluid levels, and we hadn't been successful at getting data that I could really hang my hat on or want to use in calculations.

Q. So you don't have any?

A. So we don't really have any,

And Armstrong has -- That's the way they've obtained some of their -- well, all of their information, is through shooting fluid levels like we've tried to do.

And we do have the one -- Well, we have a couple DSTs that indicate -- We've got a pretty good indication of what the reservoir pressure is in the upper sands, the initial pressure.

Q. Thank you. And during the test period, was there any evidence of interference between your wells and Armstrong wells?

A. We did not have any bombs in the hole to like do an interference test. When a lot of that testing was taking place -- well, all of the testing -- our Mark Number

4 was not drilled at that point in time. That's the nearest offset. So we don't have any data to support yea or nay.

I do have the GORs earlier that I talked about on five wells that as each next well was drilled, the GOR increased, indicating there had been some pressure interference at those new locations.

Q. After -- As I understand it, you hadn't seen this study done by --

Q. Right.

A. -- Armstrong consultants up until recently, quite recently. But is there anything there that would suggest to you that this field should be unitized?

A. Well, that's a thought. I was talking this over with a friend of mine, used to be the reservoir engineering manager, at Mesa, and he said, you know, you may have cause to unitize for proper reservoir management. He said, you may want to bring that up with the offset operators.

And then that was just a couple of days ago, and I haven't talked to Armstrong.

But that's -- We've got a reservoir that we share, a common reservoir, and we're talking about trying to manage it properly. We've got several different drives that may be coming into play, and it may in fact be a case that unitization may need to be looked at, just -- not secondary, but strictly right now for proper management of the reservoir.

COMMISSIONER WEISS: Thank you. I have no other questions.

CHAIRMAN LEMAY: Thank you, Commissioner Weiss.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Maxey, the one well -- These aren't identified, so I have a hard time in referring to them, but it's the one on your exhibit -- Oh, it's not your exhibit, I'm sorry, but Exhibit Number 3, the net D sand isopach, and it shows 4 over 32 -- 4 over 62, I guess.

That's the only well that's -- in reviewing in this, it looks like you have a very low net with a high gross.

A. I believe that's the Number 8.

Q. It's got "8" on here, that's true.

A. Mark --

MR. BRADSHAW: Mark Number 8.

CHAIRMAN LEMAY: Mark Number 8, is it? Yeah.

MR. BRADSHAW: Yeah.

Q. (By Chairman LeMay) Can you explain why that well would have a high gross and a low net, when all the others seem to have a proportional ratio to net and gross?

A. No, I can't, unless it's some kind of geological factor. But as far as an engineering standpoint, no.

Q. And you testified, as to the MER, that you have no idea what an MER might be. You said Charlie's figure of 150 may be high. Could it also be low?

A. Well, it depends. If you have -- Like I say, if there is water encroachment taking place, I've seen an increase in the GORs, which means we have a simultaneous drive taking place if there is a water drive.

So, yeah, you're too high.

Q. Could it also be too low?

A. Oh, I'm sorry. No, I don't believe it can -- What I'm saying is, we're already producing under simultaneous drive at 107 barrels a day, based on the increasing GORs I've seen.

So if you want to increase your allowable from this point, you're going to function more and more on solution gas drive as your driving mechanism and less and less on the more efficient water drive as your displacement mechanism.

So -- You follow me? That's where I'm saying --

Q. Well, I'm following you, but I'm confused. If you're inferring -- I understand you said first to get an MER you need a PVT analysis or more than we've got, additional production, and some bottomhole pressures. Then you're speculating as to 150 being too high.

My question is, if you don't have the data, is the speculation strictly a guess? Or are you --

A. No.

Q. -- throwing this out, or do you have some scientific reason for establishing an MER?

A. I think what I'm saying is, yes, we have the data that tells you -- or is telling me, at 107 barrels a day we're seeing solution gas drive, and -- with Armstrong testifying there's water drive taking place also. So we have simultaneous drive.

Any increase in rate, we will have -- the displacement mechanism will be more of solution gas drive in nature as the rate goes up.

Solution gas drive is a less efficient displacing mechanism. So as you go up from the current existing allowable right now, it's possible that you may be losing ultimate reserves if you go to 108 barrels a day instead of 107. Because the data is here -- that's what I had gone over earlier, was -- these increasing GORs are telling me that we have solution gas drive taking place, there's some gas coming out of solution right now, and that's your most inefficient form of displacement.

Q. Well, I'm trying to get a feel for this. We're talking about a hypothetical example. What would happen if the GOR went up slightly as you produced more oil, and then at some point in the -- I guess I'm confused.

Increasing GOR with increased production, to you, indicates waste?

A. To me indicates solution gas drive. If you have -- As you have increasing oil, if the GOR stays constant, that means you've got the same amount of gas coming out of solution at one point as you do at the next point, if the GOR is flat.

As you move more and more gas coming out of solution, you have more and more gas that's expanding, pushing oil to the wellbore, and you start to have more gas flow freely to the wellbore to add to what's coming out of -- in relation to the oil.

Q. I have to express some confusion. What I'm trying to do, and I guess it's the best way -- E-10, is that the one? You could have increasing GOR as a function of solution gas drive?

A. Right.

Q. If you increase the production and that is not responsible for the increase in GOR, then are you dealing with an MER that may be at a higher level?

A. I believe you're still dealing with solution gas. You don't have -- You haven't reached any kind of critical gas saturation that you're getting frequent gas flowing to the wellbore yet.

All I'm saying is, when you've got an increasing GOR, you have solution gas drive.

Q. Okay.

A. Okay? I think what you're saying, if you double the oil rate with the GOR, it's still increasing but it doesn't increase faster.

Q. No, I guess I'm saying if you're producing these wells -- and if you'll refer to E-10 maybe you can help me a little bit with this.

A. Okay.

Q. At the various production rates --

A. Uh-huh.

Q. -- are you seeing a higher GOR for the higher rate? Or are you just seeing as a historical factor in this field, you're increasing GOR?

A. No, as far as just what I've seen -- Like I said, I haven't had a real good chance to go over this.

I didn't see an increase in GOR. I think Armstrong established the fact that they didn't see an increase in GOR with the increase in rates. So the rate during their short time that they tested it, the GOR was not really rate-sensitive. So -- I believe I see what you're getting at.

I would agree that there was not an increase in the GOR, increase in the acceleration of it, with an increase in rate.

Q. So isn't that the true sense of whether a reservoir is rate-sensitive or not? As you looking at the GOR, you're looking at the GOR not in terms of the production history from the field but in terms of the various rates wells produce at?

A. If all the wells -- If all the GORs remained constant on all the wells, that may be correct.

Q. So in summary, is your testimony that you have an idea of a maximum MER, or is it that you -- We need more information to get at an MER?

A. As far as my point, yes, we would need more information.

As it stands now, I believe we're going to be -- we're going to incur some damage if the allowable is increased. And I believe there's more information needed to establish what an MER is.

But I also believe -- My impression or my interpretation is, there is not a strong water drive, and that we're going to be producing strictly by solution gas or -- Well, primarily solution gas.

If we're producing primarily by solution gas and Armstrong is allowed a three-to-one increase in allowable, and our well -- immediately offset to them can only produce at a maximum of 107 barrels now, they're in a competitive situation.

I've established the fact that there was drainage that was occurring 40 acres away when new wells were drilled. If that holds true across the reservoir, we're in a competitive situation. If they're allowed three times increase in allowable under a solution gas scenario, we stand to lose on that scenario.

If we have water drive, we're downdip, we stand to lose on encroachment.

Q. I guess I would be mixing apples and oranges here. Is there one issue on an MER: What's the maximum efficient rate to produce at? Because if you unitize the field, that would be a separate question in correlative rights. Then aren't we talking about a drainage factor, you would be drained versus you would not be drained excessively at a higher rate? Aren't those two different issues?

A. Well, the MER -- Number one, the MER on a field and on the wells, you would need to -- the MER is more dependent on the type of drive.

So first you need to establish, you need to come to terms within the field, what kind of drive do you have?

Now, from there you establish what the MER will be so you don't leave ultimates in the ground. Okay?

Q. Okay.

A. Now --

A. Isn't that separate from a correlative-rights issue on drainage?

A. I don't believe so, because if you just inadvertently establish a 300-barrel-a-day and just say that's the MER, and you bypass oil downdip and we water out, our correlative rights have been infringed upon.

Q. Okay. Well, I'm just thinking, one seems to be a waste issue, the other seems to be an I'm-going-to-get-your-oil-type thing.

A. Well, I believe -- If it's purely solution gas, I believe it's more of a drainage-type thing. Okay?

Q. Which is correlative rights, then?

A. Yes, that would be correlative rights, because we are in a competitive situation. We are disadvantaged, because we don't have the permeability and the flow capacity that their well has. Our correlative rights would be impinged upon because they would recover more reserves.

Q. I'm just trying to get the essence of your testimony. And --

A. Right, I understand.

CHAIRMAN LEMAY: Thank you very much.

Are there any additional questions?

Commissioner Weiss?

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. How do you measure GORs?

A. Well, the only data I have is off production data, so I'm --

Q. They're not measured at the well then?

A. It's measured by gas sales divided by oil production.

Q. Is there anything taken out for lease gas?

A. No, that's another point. Nothing has been -- There's no meters on lease use, and I did not use an estimate on lease use. So no, I didn't use anything for lease use, but there is lease use taking place.

Q. So these numbers aren't true?

A. Well, these numbers are -- Supposedly lease use is going to be pretty stable, pretty consistent.

CHAIRMAN LEMAY: Additional questions?

Thank you. You may be excused.

Anything else?

MR. CARR: Nothing further.

MR. BRUCE: I have no further witnesses, Mr. Chairman.

CHAIRMAN LEMAY: Can -- We have some questions here. I'm trying to establish the Read and Stevens position. It seems to be that you have no objection to consolidation of the fields, but you do object to the higher allowable for the --

MR. BRUCE: Yeah, I don't -- you know, if I can -- Mr. Maxey might know more Charlie Read's thinking, but I don't think they have a big objection to the combining of the fields. I think our geologist's exhibits show that they are continuous, the zones, whatever you call them, A, B, C or 1 and 3, are continuous across the field.

So it's more of an objection to the 300-barrel-a-day allowable.

CHAIRMAN LEMAY: Shall we take it at that and let it go? Or do you want to sum up?

MR. CARR: Mr. Bruce has asked me to please spare him a closing, and I've agreed because he has a plane to catch in an hour and --

CHAIRMAN LEMAY: I'm sorry, I didn't realize.

Is there anything else in the case?

If not, we shall take the case under advisement.

Thank you very much.

(Thereupon, these proceedings were concluded at 3:55 p.m.)

* * *

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 Commission 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 February 6th, 1994.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1994

BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
APRIL 29, 1993

COMMISSION HEARING

IN THE MATTER OF:

| | |
|---|---|
| Application of Armstrong Energy Corporation for special pool rules, Lea County, New Mexico. | CASE 10653 (DE NOVO) |

BEFORE: William J. LeMay, Director

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the New Mexico Oil Conservation Commission: Robert G. Stovall
Legal Counsel for the Commission
State Land Office Building
Santa Fe, New Mexico

MR. LEMAY: Call next Case 10653.

MR. STOVALL: Case 10653, the application of Armstrong Energy Corporation for special pool rules, Lea County, New Mexico, to be heard De Novo upon the application of Armstrong Energy Corporation. The applicant has requested that this case be continued to the next Commission hearing.

MR. LEMAY: Without objection Case 10653 De Novo is hereby continued to the Commission hearing scheduled for May 27, 1993.

BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
MARCH 11, 1993

COMMISSION HEARING

IN THE MATTER OF:

| | |
|---|---|
| Application of Armstrong Energy Corporation for special pool rules, Lea County, New Mexico. | CASE 10653 (DE NOVO) |

BEFORE: William J. LeMay, Director

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the New Mexico Oil Conservation Commission: Robert G. Stovall
Legal Counsel for the Commission
State Land Office Building
Santa Fe, New Mexico

MR. LEMAY: The hearing will come to order. Call Case 10653.

MR. STOVALL: Case 10653, the application of Armstrong Energy Corporation for special pool rules, Lea County, New Mexico, to be heard De Novo upon the application of Armstrong Energy Corporation. The applicant has requested that this case be continued to the next Commission hearing.

MR. LEMAY: Without objection Case 10653 is hereby continued to the Commission hearing scheduled for April 29, 1993. The hearing is adjourned.

BEFORE THE
NEW MEXICO OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
JULY 22, 1993

COMMISSION HEARING

IN THE MATTER OF:

Application of Armstrong Energy Corporation for special pool rules, Lea County, New Mexico.

CASE 10653
(DE NOVO)

BEFORE: William J. LeMay, Director

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the New Mexico Oil Conservation Commission:

Robert G. Stovall
Legal Counsel for the Commission
State Land Office Building
Santa Fe, New Mexico

MR. LEMAY: Call next Case 10653.

MR. STOVALL: Case 10653, the application of Armstrong Energy Corporation for special pool rules, Lea County, New Mexico, to be heard De Novo upon the application of Armstrong Energy Corporation. The applicant has requested that this case be continued to the Commission hearing scheduled for October.

MR. LEMAY: Without objection Case 10653 is hereby continued to the Commission hearing scheduled for October 14, 1993.

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING )
CALLED BY THE OIL CONSERVATION )
COMMISSION FOR THE PURPOSE OF )
CONSIDERING: ) CASE NOS. 10653 and 10773

APPLICATION OF ARMSTRONG ENERGY CORPORATION

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REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

BEFORE: William R. LeMay, Chairman
Gary Carlson, Commissioner
Bill Weiss, Commissioner
Florene Davidson, Senior Staff Specialist

November 10, 1993

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on November 10, 1993, at Morgan Hall, State Land Office Building, 310 Old Santa Fe Trail, Santa Fe, New Mexico, before Deborah O'Bine, RPR, Certified Court Reporter No. 63, for the State of New Mexico.

ORIGINAL

CHAIRMAN LeMAY: We shall now call Case No. 10653 and 10773.

MR. STOVALL: These are both applications of Armstrong Energy Corporation. 10653 is for special pool rules, Lea County, New Mexico. 10773 is for pool extension and abolishment, Lea County, New Mexico. And the applicant has requested those cases be continued until the January 1994 hearing date.

CHAIRMAN LeMAY: Without objection, the Armstrong Energy cases will be continued to the January 1994 docket.

CERTIFICATE OF REPORTER

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

I, Deborah O'Bine, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that I caused my notes to be transcribed under my personal supervision, and that the foregoing transcript is a true and accurate record of the proceedings of said hearing.

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, November 10, 1993.

Deborah O'Bine

DEBORAH O'BINE
CCR No. 63

OFFICIAL SEAL
Deborah O'Bine
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires: Sept. 19, 1994

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: ) CASE NOS. 11,225
) 10,653
APPLICATION OF ARMSTRONG ENERGY ) (Consolidated)
CORPORATION/CASE 10,653 REOPENED )

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

March 16th, 1995

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Division on Thursday, March 16th, 1995, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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# I N D E X

March 16th, 1995
Examiner Hearing
CASE NOS. 11,225 and 10,653 (Consolidated)



* * *

# E X H I B I T S

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* * *

# A P P E A R A N C E S

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* * *

WHEREUPON, the following proceedings were had at 8:32 a.m.:

EXAMINER STOGNER: At this time I'll call Case Number 11,225.

MR. CARROLL: Application of Armstrong Energy Corporation for a special gas-oil ratio for the Northeast Lea-Delaware Pool, Lea County, New Mexico.

EXAMINER STOGNER: At this time I'll call for appearances.

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe law firm Campbell, Carr, Berge and Sheridan.

We represent Armstrong Energy Corporation in this matter, and we will have two witnesses.

EXAMINER STOGNER: Any other -- I'm sorry.

MR. CARR: At this time, or later, Mr. Examiner, I will request that this case be consolidated for the purpose of hearing with the following case, Case 10,653.

EXAMINER STOGNER: Are there any objections to consolidating these cases or appearances to be made in 11,225?

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin.

I'm appearing this morning on behalf of Mallon

Oil Company.

We have no objection to the consolidation of these two cases.

EXAMINER STOGNER: With that, I will also call Case Number 10,653.

MR. CARROLL: In the matter of Case Number 10,653 being reopened pursuant to the provisions of Division Order Number R-9842-A, which Order provided for an increase in allowable to 300 barrels of oil per day for the Northeast Lea-Delaware Pool in Eddy County, New Mexico.

EXAMINER STOGNER: Other than Mr. Carr and Mr. Kellahin representing Mallon, are there any other appearances in this case?

There being none, then these two cases will be consolidated for the purpose of testimony.

And Mr. Carr?

MR. CARR: We'd request that the witnesses be sworn.

EXAMINER STOGNER: Will the witnesses please stand to be sworn at this time?

(Thereupon, the witnesses were sworn.)

MR. CARR: Mr. Stogner, at this time we'd call Mr. Boling.

EXAMINER STOGNER: Mr. Boling, this seat is reserved for you here.

ROBERT MICHAEL BOLING,

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

EXAMINATION

BY MR. CARR:

Q. Will you state your name for the record, please?
A. Robert Michael Boling.
Q. And where do you reside?
A. Roswell, New Mexico.
Q. Mr. Boling, by whom are you employed?
A. Armstrong Energy Corporation.
Q. And in what capacity are you employed by Mr. Armstrong?
A. Consulting petroleum geologist.
Q. Mr. Boling, have you previously testified before this Division?
A. Yes.
Q. At the time of that testimony, were your credentials as a petroleum geologist accepted and made a matter of record?
A. They were.
Q. Are you familiar with the Applications filed in each of these cases?
A. I am.
Q. And are you familiar with the Northeast Lea-

Delaware Pool and the temporary rules that have been promulgated for that pool?

A. Yes, I am.

Q. Have you made a geological study of the pool?

A. I have.

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

EXAMINER STOGNER: They are.

Q. (By Mr. Carr) Mr. Boling, could you briefly summarize what Armstrong Energy Corporation is seeking with these Applications?

A. Armstrong is seeking to make permanent the special rules that were granted to us about a year ago that increased the allowable in this field from the statewide depth allowable of 107 barrels a day to 300 barrels a day and an adoption of a gas-oil ratio in excess of the statewide allowable of 3000 to 1.

Q. Now, this case originally came before the Division in January of 1993; is that right?

A. That's correct.

Q. And what was Armstrong seeking at that time?

A. At that time we had drilled the first well in our drilling program and sought a special oil allowable of 300 barrels a day to be set for the pool, based on the performance of our well.

Q. And that Application came before Examiner Catanach?

A. That's correct.

Q. And what was the action taken by the Division on that initial Application?

A. The result of that hearing through Order R-9842 was a denial of the increased allowable based on a lack of production history and other pertinent data relating to the production of the well.

Q. When were temporary rules adopted for this pool?

A. March the 10th of 1994.

Q. And was that the result of a *de novo* hearing before the Commission?

A. It was.

Q. At the time of that *de novo* hearing, what additional information had become available to the operators in the pool?

A. In that year between the two hearings, nine additional wells were drilled by either Armstrong and/or the offset operator -- in this case Read and Stevens -- and we had about 16 months of productive history on our first well, plus the productive history of these new wells, and additionally some -- the subsequent additional geologic information that came along with drilling the well.

Q. At that time Read and Stevens appeared and presented their own geological interpretation --

A. They did.

Q. -- did they not?

A. They did.

Q. And what has changed in terms of the Read and Stevens operation since that time?

A. Since the hearing in March of 1994, there have been four additional wells drilled, one by Armstrong, three by Read and Stevens, and the result of those four wells tend to support our -- Armstrong's original geologic interpretation, as opposed to Read and Stevens'.

Q. And at this time is it not true that Read and Stevens is operating wells that also meet the higher allowable?

A. That's correct.

Q. Now, in addition to the drilling of the four additional wells since the last Commission hearing on this matter, what additional information do you have on the reservoir?

A. We have a series of pressure tests that were requested by the Commission, and we went through a series of production tests where we varied the productivity of the wells for a set period of time to try to monitor any pressure decrease or water encroachment that might occur.

Q. We also have the one-year additional production history on the reservoir?

A. That's correct.

Q. You indicated that of the four wells drilled since the last hearing, one of those wells was drilled by Mr. Armstrong --

A. That's correct.

Q. -- is that correct?

A. That's correct.

Q. Were you able to obtain any PVT data on that well?

A. Our intention was to acquire that data on that well, but unfortunately we did not find the reservoir in that location. We had found the edge of the productive reservoir. There was no reservoir present in that well. So we were unable to acquire the data.

Q. Let's go to what has been marked for identification as Armstrong Energy Corporation Exhibit Number 1.

A. Okay.

Q. First, Mr. Boling, I'd ask you just to identify that new well you just referenced.

A. Okay, the most recent well is in the west half of Section 2, in the southwest of the northwest, labeled 5.

Q. All right. Could you just generally explain the other information set forth on Exhibit Number 1?

A. Yes, this is basically just a location map in the area of the Northeast Lea-Delaware field.

The yellow acreage in Section 2 is earned and unearned acreage that Armstrong Energy has under contract or has earned.

The map also shows currently all the producing wells that are in the Northeast Lea-Delaware field.

Q. Mr. Stubbs will be presenting a map later in our presentation that actually shows the field boundaries --

A. That's correct.

Q. -- is that correct?

A. That's correct.

Q. All right. Let's go to Exhibit Number 2. Could you identify and review that for Mr. Stogner?

A. Yes. Exhibit Number 2 is just a type log on one of our wells.

If you'll refer back to the map, the index map, this is the Mobil Lea State Number 2, which is located in the northwest of the southeast quarter of Section 2.

The portion of the well that I have on -- The portion of the log I have here identifies the four basic sand packages that we have been dealing with in this area. Each of these -- This is an informal nomenclature that I came up with of just first, second, third and fourth sands. Each of these sands is separated from the sands above and below by some form of carbonate barrier. Therefore they're separate reservoirs, they're not vertically connected.

In the area of the west half of Section 2 -- or in Section 2, the south half of 3 and the north half of 10, there are two primary producing reservoirs. One is -- The first is the first sand, which is the first sand encountered up there. Now, this reservoir primarily produces at this time in the south half of 3 and the north half of 10.

The second sand interval we have found to be wet in all of the wells that we've drilled, and as far as we know, all the wells that Read and Stevens has drilled, that sand appears to be wet.

There is a -- appears to be a grain-size differentiation in the second sand from the first and third sands, and there's a possibility that the grain size has affected the permeability to oil in that reservoir.

The third sand is the sand that is our main reservoir sand, and this one in which we have six producing wells in, in Section 2.

And the fourth sand lies below the third sand. And again, it is a sand that in all the currently producing wells in 2 and 3, that sand appears to be wet and nonproductive.

Q. Now, Mr. Boling, the type log that's on the Mobil

Lea State Number 2 well, right?

A. Correct.

Q. And that well is located in the northwest of the southwest --

A. That's correct.

Q. -- of Section 2?

A. That's correct.

Q. All right, let's go to Exhibit Number 3, your cross-section. Identify this, review the line of cross-section, and then the other information contained on this exhibit.

A. That cross-section is kind of long.

This is a stratigraphic cross-section. As you can see from the index map on the right-hand side, it goes from Section 35, the southeast southeast of Section 35 on the northeast, down to the southwest, crossing Section 2 and portions of Section 3 and 10.

The intent of the map is twofold, or really threefold.

One is to show the variability not only in the thickness of the sands as we cross the field area, also the changes in facies that the sand undergoes, and thirdly is marked on here in the dashed line the oil-water contact in our primary reservoir.

We start on the right-hand side, the well labeled

Pennzoil Mescalero Ridge Unit Number 3. Now it's currently owned and operated by Mallon.

This well was the first well drilled in the field, and it -- if you could -- if you look at the log where the perforations are marked, you can see that that's in a carbonate interval, which I have correlated as equivalent to the second sand interval in our wells.

As you can see, there's very little of our main reservoir sand present. It's very tight, if there's any sand there at all. And this well, through October of 1992, it made about 24,000 barrels.

If we come to the next well, the Armstrong Energy Corporation West Pearl State Number 1, this well was perforated in our main reservoir. And you can see there's only about 20 feet of sand present there, but this well did come in at over 100 barrels a day. It is above the oil-water contact.

This well, based on productive history of this well and observation over the last several years, does not seem to be hooked into the drive mechanism that we think is providing the energy for the main part of the reservoir further west. This appears to be a normal Delaware gas solution drive reservoir in this particular well.

If you look at the West Pearl State 2, you begin to see the dramatic change in facies. You see we have a very thick interval marked in there that indicates the third interval, but it's mostly carbonate with just a little bit of sand left in the bottom in which we perforated it. It is all above the oil-water contact.

This well indicates to me that we are crossing from one depositional regime into another. This well happens to be in between two little sand pods. We've got a dolomitic facies in between. The dolomite has oil in it, the reservoir has oil in it here, but it's a -- there's very little energy involved. It appears also to be more of a gas-driven reservoir than water-.

When you come to the next well, labeled the Harken Energy Corporation Mobil State Number 1 well, this well is producing out of the first sand interval. It is the only well in Section 2 that has any significant production associated with the first sand interval.

If you'll look at the third sand interval, our main reservoir, you'll see the sand is only 18 feet thick in this well, and it is below the oil-water contact.

The next well is the Armstrong Energy Corporation Mobil Lea State Number 1, our first well. The first thing you notice is, you get a dramatic thickening in the sand, from about 18 feet of porosity to about 96 feet of porosity.

This well was drilled -- The Mobil Lea State

Number 1 was drilled in October, 1992. It was perforated and came in flowing 600 barrels a day.

This is the well on which we based our initial request to increase the allowable. We could not pinch the well back, we couldn't get it back to 100 barrels a day without the pressure regime changing dramatically downhole, and we were concerned with that.

So based on the performance of this well over the first several months, we came and initially asked for the increased allowable.

The next well is the Mobil Lea State Number 2, direct west offset to the Number 1. The sand actually thickens in this direction. Again, we have about 100 feet of porosity in this well, also -- most of which is above the oil-water contact. This well came in flowing in excess of 200 barrels a day.

The next well is the Spectrum 7 Mobil Lea State Number 2. It's marked as a dryhole. If you'll notice, it is slightly -- It is one location south of the Mobil Lea State Number 2.

We have similar thicknesses of sand, slightly thinner, about 76 feet of sand as opposed to 100. But most of that sand is below the oil-water contact.

We eventually offset this well in an unorthodox location. It was able to get, instead of 11 feet above the oil-water contact, about 38 feet above the oil-water contact, and had a well that produced in excess of 200 barrels a day.

The next well is the Mobil Lea State 3. Again, we have a lot of sand in this well, not so much above the oil-water contact, only about 20 feet, but this well also came in in excess of 200 barrels a day.

The next well was a well, the Number 4, is Read and Stevens' well. It's in Section 3. It is one of -- It is the best third-sand reservoir well they have. They have about 22 feet above the oil-water contact. Very similar to the Number 3 in terms of the net feet of porosity above the oil-water contact. But where our well came in in excess of 200 barrels a day, theirs came in at 92 barrels a day.

Based on the performance of these two wells and the initial IPs and the geology, we were able to present it at the *de novo* hearing, a case that showed that we had a separate reservoir, we had a different quality reservoir in Section 2 than in Section 3 and 10, based on the performance of the wells, and also the fact that we were much higher structurally than Read and Stevens.

If you continue to go to the southwest, the Well Number 10, as you can see, has about eight feet of sand above the oil-water contact. This well is currently nearly watered out. It came in for 60 barrels a day.

The next well, the 7, is completely below the oil-water contact, and it was 100-percent water when they perforated it.

The 6 has about 30 feet above the oil-water contact. It came in for about 117 barrels a day. It is also beginning to water out, and it reflects the oil water contact.

And the last well is the 5. You see we've passed out of the sand facies back into the carbonate facies again.

So as we've crossed the field, we've gone from dolomite to tight sand to dolomite to good sand, to less quality sand and back to dolomite. So this is kind of a complete lithologic panorama of what's going on across this field in our main producing horizon.

Q. All right, Mr. Boling, let's go to your Exhibit Number 4, your net isopach of the first sand, and look at that interval for a minute.

A. Okay. Exhibit Number 4 is an isopach map, net porosity isopach map in the first sand interval in the areas of Section 2, 3 and 10.

Now, the purpose of this map is to show you two things:

The blanket nature of the sand. The sand in this interval is continuous across the field area of Section 2 and 3. There does not seem to be a break in deposition in this sand interval as we cross Sections 2 and 3.

Also, this reservoir, Armstrong Energy has serious concerns about correlative rights in this reservoir. In the south half of Section 3 and the north half of Section 10, Read and Stevens has 11 producing wells that have taken a million and a half barrels of fluid out of that reservoir, nearly 900,000 barrels of oil, in less than four years.

I'd like to direct your attention to the east half of Section 2. You'll note two wells with the notation "66 feet" and "14 feet". The well marked "66 feet" is the Harken -- or the Spectrum 7 Number 1 well. This well was completed in 1986. It's made about 80,000 barrels. It's got 66 feet of reservoir in it.

We drilled -- The well labeled "14" is the West Pearl State Number 2, a well that was in the carbonate facies in our main reservoir but had 14 to 18 feet of reservoir that was about 30 feet updip to this well. We recently completed this well and found it depleted.

So in eight years that well in the first sand interval marked "66" has depleted this area out there even though we were updip to it.

Our concern is that Read and Stevens has got wells in Section 3 that have been producing in excess of

100 barrels a day for four years already, and we have very good, thick intervals and good shows of this first sand reservoir in the west half west -- southwest of 2, in the two wells labeled "54" and "70", the West Pearl State 2 and 3.

We have serious concerns that we're getting drained right now, bad, and if we don't have an allowable, while these two wells are still producing in excess of the daily allowable in the third sand interval, we can't go get that first sand and protect those reserves and give ourselves a fair right -- our fair share of the reserves, unless we had the higher allowable permanently in place.

It's very critical to us in this particular interval. I will show you my geology that's been borne out by drilling, that in the third sand interval there is a separation in the deposition, and in the oil leg we are not connected.

So our productivity in our wells has not affected Read and Stevens, but theirs in this reservoir has affected our potential to recover reserves.

Q. Now, Mr. Boling, you indicated that Read and Stevens is producing 11 wells out of the first sand?

A. That's correct.

Q. How many wells does Mr. Armstrong have in that first sand?

A. We have two wells that are poor producers in the first sand due to thinness of the -- This West Pearl State 1, which is depleted by the Harken well, and the Number 5, the well that I initially said we had no third-sand reservoir in, is producing out of a thin interval in that first sand, but it's less than 25 barrels a day.

Q. Are those the only two wells that Mr. Armstrong has that can be completed and produce from the first sand?

A. No, they are not.

Q. How many are there?

A. We have at least four more wells that look like they could be recompleted in the first sand.

Q. If the pool rules that are now in place on a temporary basis are adopted on a permanent basis and the gas-oil ratio is increased, would Armstrong then have the opportunity to go in and produce the reserves in the first sand that now are subject to drainage?

A. Absolutely.

Q. Are there also additional zones in the Delaware that could be potentially productive?

A. Yes, recently -- There is a deeper sand in the area of -- inside the unit that has been recently completed, deeper than any of these intervals, which is currently capable of producing in excess of the statewide allowable by itself.

It underlies, based on my mapping, some of our acreage and where we have wells present right now. So that is now an additional or a third highly productive interval that we wouldn't be able to exploit without the higher allowable, and it is currently being produced by operators offsetting us.

Q. In terms of attempting to make completions in these other zones, if the rules revert to the statewide rules for this pool, would it be economically viable for any operator to go back and try and attempt a completion in these other zones?

A. Well, eventually it would, but you would have to wait till your primary zone depleted. And by that time, of course, you've already been drained in your other reservoir.

Q. All right, let's go to Exhibit Number 5 --

A. Okay.

A. -- the structure map on the base of the third sand, and I'd ask you to review that for Mr. Stogner.

A. Number 5 is my structure map on the base of our main producing interval, and this map is on a 10-foot contour interval, and that's why it appears to be as detailed as it does.

But the two critical things that this map shows is that there are two significant depositional pathways.

One begins in the southwest of the southwest of Section 3 and progresses southeast across the east half of Section 10, that low spot. That is the spot where most of Read and Stevens' third-sand reservoir lies.

In the southeast southeast quarter of 3 and the northeast northeast of 10, there is a structural nose, a topographic nose that separates that depositional pathway on the southwest that Read and Stevens has production established in from the one that we have production established in, which is in the southwest quarter of Section 2.

We know that the nose exists, based on the topographic information that we got out of the wells, plus the fact, if you'll look in the northeast of the southeast of Section 3, there's a dryhole marked minus 2320. That's the Mark Number 8. There is no sand in our third producing interval in that well, and that well was critical to proving at the *de novo* hearing that the nose existed.

One of the major conflicts in the geologic interpretation was whether or not that nose was there and the sand was continuous across those two sections, much like the first sand.

My contention was that this geologic interpretation made more sense based on the productivity of the wells and the appearance of the reservoir than not having the nose there. Also, the rules of contouring kind of dictate that you put a nose in there, and it fits.

So we -- The critical thing here is that we have two separate pods of sand, separated topographically, not connected in the oil leg, so productivity on our side does not affect productivity on their side.

Also, there is a third depositional pathway in the southeast of 35 and the northeast of Section 2. It is not connected to the water leg that the wells in the southwest quarter of 2 are. It is the area where there appears to be a solution gas drive mechanism in the reservoir.

Q. All right, Mr. Boling, let's look at the net isopach on the third sand, Exhibit Number 6.

A. Okay. Exhibit Number 6 is a net porosity isopach map, 15-percent porosity being the minimum, that shows the net feet of porosity in our main producing interval.

As you can see from the isopach map, it bears out the original structural interpretation. If you look from the southwest quarter of 3, down across the east half of 10, you have the thick sand up to 100 feet of porosity, which corresponds with the low spot or the depositional pathway that we have on the structural map. The sand is right where it should be in the low spot, and it thickens as it should in the deepest part of the low spot.

You have -- The structural nose is exhibited by the lack of deposition, the thinning in deposition as you cross the nose in the southeast of 3 and northeast of 10, you thin to where I say there's no sand crossing that nose.

You come to the northeast, you're dropping to the next depositional pathway, and there's the next sand thick approaching 100 feet of porosity, in which our four best producing wells exist.

And you pass up into the northeast part of 2 where we have one well with 24 feet of porosity.

This map reinforces the structural interpretation of the nose and the two depositional pathways.

Q. Now, Mr. Boling, we've looked at the base of the sand and we've looked at the isopach of the sand. Let's go to Exhibit Number 7, the structure map on the top of the interval, and ask you to identify and describe that for the Examiner.

A. Exhibit Number 7 is the structure map on the top. And actually, this map is functionally not as important as the other two maps; it's basically -- I just mapped the top to check my work on the base and the isopach. If you take the top and the bottom, the isopach map, that will fit in between even better. The numbers better work out.

But basically you see the same thing. You see the depositional pathway across 3 and 10, the one that we're in, in Section 2, and the nose is still present in Section 10.

Again, two separate depositions of sand, not connected in the productive oil leg.

Q. Mr. Boling what conclusions can you reach from your geologic study of the Delaware formation in this area?

A. The major one is -- Actually twofold, I think. The major one is that our initial structural interpretation has been borne out to be correct, that we do have separate reservoirs in this third-sand interval, separated by a topographic nose and not connected.

We know that this is a particularly dynamic reservoir in the southwest quarter of Section 2. We attribute this to water drive, which is highly unusual in the Delaware formation.

I think the geology also bears out the fact that the first sand, while we have a similar drive mechanism, we have a different kind of depositional history in the first sand in that it is more of a blanket sand; it does cross and is contiguous across the whole field area.

We know there's a lot of oil in that sand. 900,000 barrels have been taken out in less than four years.

But we also know that because of the permeability of those sands, and based on the performance of the Harken well depleting our updip location, those wells are draining a pretty big area.

And our concern again is that while Read and Stevens has had four years of production in excess of allowable, we have been unable to get into our first sand reservoir due to the limitations of the allowable, and we have a grave concern, because we're connected in that sand, that we are not going to get our fair share of the reserves in the southwest quarter of 2.

Q. Do you see two primary reservoirs?

A. Yes, sir, at this time in the upper part of the hole I see two. There is a -- this third reservoir that's deeper, and as I stated, it is producing offset to us in excess of the allowable that it would have, and my mapping indicates that that reservoir lies in portions of Section 2, under proration units where we have producing wells with one or two reservoirs capable of production. Now, we have a third possibility, which compounds our problem of the allowable.

Q. As you see these separate zones, do you see any evidence of any vertical connection?

A. Absolutely not. If you refer back to the type log, you will see that at least in the upper part of the hole, every one of these sands is, as I stated earlier, separated by a carbonate area. There is no vertical connection in these reservoirs.

Q. The first sand is continuous across the reservoir?

A. The first sand is continuous across the field area, yes, sir.

Q. And the third sand?

A. The third sand is continuous -- is isolated in pockets across the field area, separated topographically, and the first sand is not separated topographically.

Q. Will Armstrong call an engineering witness in this case?

A. Yes, we will.

Q. Were Exhibits 1 through 7 prepared by you?

A. Yes, they were.

MR. CARR: At this time, Mr. Stogner, I move the admission into evidence of Armstrong Exhibits 1 through 7.

EXAMINER STOGNER: Any objections?

MR. KELLAHIN: No objections.

EXAMINER STOGNER: Exhibits 1 through 7 will be admitted into evidence.

MR. CARR: And that concludes my examination of Mr. Boling.

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin, your witness?

MR. KELLAHIN: Mr. Examiner, I appreciate your indulgence. I need to ask Mr. Carr some questions off the record. If we might have a momentary, if you'd give me a minute or two, I'd appreciate it.

EXAMINER STOGNER: Let's take a five-minute recess at this time.

(Thereupon, a recess was taken at 9:08 a.m.)

(The following proceedings had at 9:20 a.m.)

EXAMINER STOGNER: Back on the record.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

Mr. Examiner, I'm taking a copy of Mr. Boling's Exhibit Number 1 in which he shows the area, and I have a copy of the *Byram's* nomenclature for the pool, and I want to outline what the Division currently has as the boundary for the pool and then to show that to both you and Mr. Boling, followed by some questions.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Boling, I've taken a copy of your Exhibit 1 and a copy of the *Byram's* nomenclature for the pool and have scribed an area with a red pen that shows the approximate boundaries of what we're dealing with when we look at this pool under the Division rules. Do you see that outline, sir?

A. Yes, sir.

MR. KELLAHIN: Mr. Examiner, I'm going to leave this copy of Exhibit 1 with you, in which I have scribed the pool boundary, and a copy of the *Byram's* nomenclature for the pool so that you can visualize what the Division currently has for the pool boundary.

Q. (By Mr. Kellahin) Mr. Boling, when we look at your Exhibit Number 4, that is your net isopach map of the first sand interval?

A. Yes.

Q. How do you -- This exhibit is based upon data you had available to you, largely derived from the Armstrong log information, as well as Read and Stevens log data?

A. That's correct.

Q. Does the zero line, if you will --

A. Yes.

Q. -- that runs east and west across the central portions of Sections 2, 3 and 4 represent the actual zero limit line of this first sand member of the pool?

A. I would say in Section 2 it does. In Section 3 it apparently probably does not at this time, because there has been a recent well drilled in the southwest -- I mean in the northwest of the southeast of 3, which is not represented on this map, that has an extremely thick interval of the first sand, which would tend to start pushing that zero line north in Section 3.

Q. All right, sir. If I correctly understand the method, then, this zero line is based simply on the fact that this was the data that you had to work with in order to determine where that current line was now --
A. That's correct.
Q. -- represented?
A. That's correct.
Q. And as further development takes place in Sections 3, as well as north of 3, then that zero line could be extended if the data justifies that?
A. That's correct.
Q. When we look at Exhibit Number 6, which is the third sand interval of the pool, the same thing still applies insofar as you have mapped the third sand based upon available data?
A. That's correct.
Q. And that as additional wells are drilled north in Sections 3, 35 and 34, that certainly could extend the reservoir in that direction?
A. Yeah, that's possible, yes.
Q. All right. Let's go back to Exhibit 1 where I've shown the current boundary.
When the Division was first discussing this pool, in fact, there were two pools involved, were there not?
A. Yes, sir, there was the Quail Ridge and the

Northeast Lea.

Q. All right. The Northeast Lea-Delaware was generally in the eastern portion, the Quail Ridge was down in Sections 9 and 10, if I remember correctly?

A. That's correct.

Q. All right. And they were put together as one pool?

A. That's correct.

Q. When we look at the current political boundary that the regulators are using for the pool, do you as geologist see any reason not to utilize the current pool boundary and have all the wells within this boundary subject to the same rules and regulations?

A. No, I do not.

Q. All right. Is there a reason to have it done that way?

A. Yeah, in my mind there is. First of all, I think from a functional point of view, it's a lot easier for the regulators.

But more importantly, the wells that have recently been drilled in Section 34, although we are not privy to that data, I have briefly looked at a log from the Mallon Well Number 12, which is in the southwest of the Southeast of Section 34. That well is strikingly similar in its characteristics, the appearance of the sand on the log, to our wells in the southwest of 3 -- of 2. We have the same depositional sequences, we have a first sand, we have a second sand, we have a third sand, they approach the same thicknesses, they appear the same.

In my mind, geologically what has happened is that you had a similar set of depositional events taking place up in the east half of Section 34, as we did down in 2 and 3. Lacking any better information than what I have right now, I would predict that those -- the sands up in 34 will be -- will perform in a similar manner to the sands in Section 2, 3 and 10, and therefore could be expected to have the same kind of allowable problems.

Where you have stacked reservoirs, while they're not vertically connected, they all are full of oil and they all can produce in excess of allowable by themselves, and you have several reservoirs.

So I would expect that condition to exist in Section 34 also, based on the information I have available to me now.

Q. From your geologic perspective, do you see it practical that the Division could take the Delaware vertical limits and subdivide it in this area so that we're dealing with unique, isolated reservoirs separated from each other?

A. Well, we tried that, and it didn't work.

Q. Doesn't make any practical sense, does it?

A. No, it doesn't. No, we were turned down on it. We attempted to do that at one time, and -- as a way to get around the allowable problem, and we found out that -- practically that wasn't going to work.

Q. All right. For this particular area, within this horizontal boundary, then, you don't see any practical reason to try to subdivide it vertically?

A. No, I don't think you can.

Q. Because you're dealing with these multiple intervals, potentially as many as four as you've defined it, that if you were fortunate enough to be successful in one and achieve a maximum allowable under the statewide rules of 107 barrels, that low limit effectively precludes you, then, from perforating any of the other intervals?

A. That's correct.

Q. And because those intervals are laterally continuous in adjoining 40-acre spacing units, an inequity can be created --

A. Absolutely.

Q. -- by the lower allowables?

A. Yes.

Q. Where one operator has chosen to perforate one zone, the other operator offsetting him is producing in the third zone, if you will?

A. Uh-huh.

Q. The two are draining each other, but neither is fairly competing in both zones?

A. That's correct.

Q. And the only way to achieve that successful equity is to increase the oil rate?

A. That's correct.

MR. KELLAHIN: Okay. Thank you, Mr. Examiner.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

EXAMINATION

BY EXAMINER STOGNER:

Q. In referring to the cross-section, the water contact, that's marked as you predicted it at this point; is that correct? Or initial?

A. No, that is the oil-water contact that we determined based on the well information from all those wells. It hasn't changed. In that particular reservoir, that's the oil-water contact.

Q. In the number --

A. -- three.

Q. -- three sand?

A. That's right.

Q. Now, let me see if I am understanding. The number three sand is predominantly a water drive?

A. Yes, sir, that's correct.

Q. And you've only shown one well to have some perforations in that number two sand, and that was that Read and Stevens North Lea Federal Number 5?

A. That's correct. We actually tried it in the West Pearl State Number 2, which is in the southwest of the northeast, and found it to be wet, in both of those wells found that sand to be wet.

Q. Now, are they presently producing or were they squeezed?

A. These perfs in our well were squeezed, and I think they've plugged the Number 5. I don't think it produced anything.

Q. And the number four sand is not productive -- Or I take that back. There is some perforations in that North Lea Federal Number 5 again?

A. Yeah, they tried it in that one. They've tried everything in that hole, looking for something, didn't find any.

Q. But it is nonproductive?

A. It's nonproductive also, appears to be wet everywhere.

Q. What type of deposition change is there between the first sand and the third sand? What -- The grain size and --

A. The grain sizes are very similar. Actually, it appears to me that both the third sand and the first sand have larger grain size than normal for the Delaware. And that's one of the reasons why we got such tremendous reservoir in those two sands; the permeabilities are excellent, particularly in the first sand.

The perm in the third sand seems to be better on our side than over in Section 3 and 10. I think that may be a function of the energy, depositional energy, we may have had a little higher energy environment on our side, cleaned it up a little bit more than on the 3 and 10 area. But I would say functionally, depositionally, they are very similar.

The big difference seems to be in the second sand. The second sand seems to be much finer grained. And as I stated earlier, we think one of the reasons why it's wet -- We've seen this thing in updip positions across the field and we always have shows in it, but we've never been able to get anything out of it but water. And so it appears that the grain size may be affecting the permeability of oil in that reservoir.

That would indicate the fact that you have this large grain size or larger grain size, higher energy environment in the third sand, you have some kind of energy hiatus, probably the water level increased a little bit, you slow down the energy, you get finer-grain deposition taking place in the second sand, water level drops again, you get higher energy, you get the second pulse of deposition, it gives you the larger-grained stuff again, and that's the first sand that didn't -- that's the end of the depositional cycle here.

If you go upsection, you're in carbonate, there's no more sand. We're extremely close to the shelf edge here, transition between shelf and basin rocks.

Q. Due to the higher porosity -- perhaps I need to ask the reservoir engineer that, but you seem to be somewhat knowledgeable. Have you seen any indication of water coning?

A. No.

Q. No?

A. We have not seen -- We did extensive production testing as a requirement of the *de novo* hearing order, where we ran the production from a hundred barrels a day to 300 barrels a day for an extended period in time and saw no increase in water at all. In fact, we have two wells where the water cut has gone down.

Q. Were the wells that Armstrong completed in that third sand interval, were they fractured or stimulated in any way?

A. Yes, they were all fractured, you know, hydraulically fractured.

Q. Hydraulically fractured. Was there any test done on the unstimulated flow?

A. No.

EXAMINER STOGNER: No? I have no other questions of Mr. Boling at this time.

Any further redirect?

MR. CARR: No further questions.

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: You may be excused at this time, Mr. Boling.

Mr. Carr?

MR. CARR: At this time we call Mr. Stubbs.

BRUCE A. STUBBS,

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

EXAMINATION

BY MR. CARR:

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

A. Bruce A. Stubbs.

Q. And where do you reside?

A. Roswell, New Mexico.

Q. By whom are you employed?

A. Armstrong Energy Corporation.

Q. And in what capacity are you employed in this matter?

A. I'm a consulting petroleum engineer.

Q. Mr. Stubbs, have you previously testified before this Division?

A. Yes, I have.

Q. At the time of that testimony, were your credentials as a petroleum engineer 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, sir.

Q. Are you familiar with the Northeast Lea-Delaware Pool and the temporary rules that have been established for this pool?

A. Yes.

Q. Have you made an engineering study of this pool and the wells therein?

A. Yes, I have.

Q. Is your study contained, and the results of that study, contained in what has been marked for identification as Armstrong Exhibit Number 8?

A. Yes, that's correct.

MR. CARR: Are Mr. Stubbs' qualifications acceptable?

EXAMINER STOGNER: Any objections?

MR. KELLAHIN: No objection.

EXAMINER STOGNER: Mr. Stubbs is so qualified.

Q. (By Mr. Carr) Mr. Stubbs, let's go to Armstrong Exhibit Number 8, and I'd ask you to first go to the information behind Tab 1 and identify this for the Examiner.

A. This is just a verbalization of the conclusions that I've arrived at in studying this -- the Northeast Delaware field.

Q. And then behind that, behind the other tabs, are the supporting data, the data that supports the conclusion?

A. That's correct.

Q. All right. Let's go to Tab 2. Would you identify the first page behind that tab?

A. Exhibit B-1 is a field outline of the existing rules as of September 1, 1994, and I think we've just learned that in the last few weeks or maybe the last month or so, that the field has now been extended up into Section 34.

Q. And the Exhibit 1, Mr. Boling's Exhibit 1, on which Mr. Kellahin has placed the pool boundaries, those would be the current boundaries?

A. That's correct.

Q. And this is just the boundaries as they existed in September of 1994?

A. That's correct.

Q. All right, let's go to the next page, which is marked down in the bottom corner B-2, and would you identify that?

A. This is a listing of all the wells in the Northeast Lea-Delaware Pool and any other significant wells within a mile radius.

It also gives the location, perforated intervals and any tests that were performed on those intervals.

Q. This also includes the recently completed Mallon wells in Section 34?

A. That's correct. I also might mention that in the month of, I believe, February, they just completed the Number 12 well, which is not on here.

So the data is -- none -- Very little data on these wells is available; they've just been done in the last two months or so.

Q. Let's go back two pages to what is marked in the lower right corner B-3, and I would ask you to identify and explain what this table shows.

A. This is a summary of production by well, by the sand interval that they're producing out of.

As you look down at the bottom of the total line, the first sand has produced 886,000 barrels, 414 million cubic feet of gas, 302,000 barrels of oil.

Third sand has produced 569,000 barrels of oil, 426 million cubic feet of gas, 229,000 barrels of water.

Right below that you'll see an estimate of the original oil in place, and we'll get into how that was calculated in a minute.

But we've roughly recovered a little over four percent of the oil in the first sand and about 10.5 percent of the oil in the third sand.

Q. All right. Let's go to Tab 3 in Exhibit Number 8. Would you identify the material contained behind this tab?

A. This is a similar type log that Mr. Boling presented, showing the intervals that we classify as first, second, third and fourth sands.

Q. Let's go now to Tab 4.

A. Okay, Mr. Boling has pretty well characterized the sands, and what I have done in Exhibit D-1 is, I've taken the porosity, the oil saturation, thickness of each well in the first sand, given it a value and then plotted it on a map and filled in between each well to smooth it out a little bit so you can kind of tell what the reservoir looks like, and it's, you know, a digitized representation of the reservoir.

Each square represents an area 220 feet by 220 feet, which is roughly 1.1 acres.

Using that data we can come up with a reservoir volume, and we can further identify where the maximum oil concentrations are.

Turn to the next page, D-2, this is looking straight down at the reservoir, and you'll see that there's what amounts to -- what I call three fingers. There's a main finger on the far west side, a smaller one in the middle, which is where the Armstrong wells are, and there's a little pimple over on the far right side where the Mobil State Number 1 well is, and the West Pearl State Number 2.

But the main thrust of the first sand is on the far west side where the Read and Stevens wells are, and it runs in a north-south direction.

Q. Okay, let's go to the next map, marked Exhibit D-3, and I would ask you just to explain how this differs from the preceding exhibit.

A. This is the same map; it's just a different view, so you can get kind of a different perspective on the relative values. This is a side view.

You can see the main channel on the far left side, a north-south trend, with drilling of the Mark Federal Number 7, which is in the south half of Section 3. It has a -- It probably has one of the best first sand sections in the area.

This leads us to believe, and I think Mike touched on it, that that main channel continues north into the north half of Section 3 and probably ties into the Mallon wells in Section 34. It's a large channel, a large finger, and it's headed right straight at the Mallon wells.

Q. What is shown on the next page, the bubble chart?

A. Okay, Exhibit D-4 is a bubble chart showing the relative values of the oil production, and they correspond real well to the deposition of the three fingers.

The main oil producers fall right in the main channel on the west side. That's the Mark Federal Number 1 well, the Mark Federal Number 2, the Northeast Lea Federal Number 5. That all falls on that main trend.

On the far right side, the big dot is the Mobil State Number 1; that's the Mid-Continent well. And you'll notice just to the north of that is the West Pearl State Number 2, which has just been completed in the first sand. And that first sand in that area, the pressure is pretty well depleted, and the West Pearl State 2 is about a 10-barrel-a-day well.

There's a big hole in the middle there where the Armstrong wells are. They have good looking first sands; they just haven't been perforated yet.

Q. All right, let's go now to the next page and take a look at the gas production from the first sand.

A. Okay, the gas production pretty well ties with the oil production. The bigger oil producers have the bigger gas production, the bigger cum gas production.

One interesting thing from this map, the wells that are on the south end of the field have pretty low or pretty stable gas-oil ratios, and we feel we kind of feel like at this point that there's -- water influx on the south end is keeping the reservoir pressure up.

Q. Okay, let's go to the next page, the water production. How does that information compare to the statement you just made about the water?

A. You'll notice the larger dots on the North Lea Federal 8, North Lea Federal 7 and the North Lea Federal 9 are on the south end of the field, and they're -- consequently have a higher water production. They're closer to what we feel like is the oil-water contact in the first sand.

Q. The last page in this section, or the next page in this section?

A. Okay, D-7 is a summary of the first sand production.

Presently the first sand wells are producing about 25,000 barrels a month or a little over 800 barrels a day.

In the last year we've seen a little increase in the GOR from about 350 cubic feet per barrel to about 750 cubic feet per barrel. This leads us to believe that some areas in the field are now at or right below bubble-point pressure.

Q. Okay, and it also shows a general water increase?

A. Exhibit D-8 is the water curve. The water curve is the heavy dashed line, and you'll see that it goes below the oil line and then in about the last quarter of 1993 mirrors the oil lines. There is a slight increase in water production; that's primarily from the wells at the south end of the field.

Q. Now, Mr. Stubbs, the information contained behind Tab 4 is on the first sand, correct?

A. That's correct.

Q. And how much of that production has actually been produced by Read and Stevens to date?

A. Probably in excess of 95 percent. Like Mike, Mr. Boling, said, they only have two wells, and they produce combined about 20 barrels a day. There's three Snow Oil and Gas wells that probably don't produce much over 20 barrels a day.

Q. And when we look at the information behind Tab 4, we not only see these large producing legs in the reservoir, but they appear to also extend up toward and into Section 34?

A. That's the indication right now, is that main channel -- main finger extends through Section 3, all the way into 34.

Q. All right. Let's go to Tab 5 in Exhibit A. Could you identify the documents behind Tab 5?

A. Okay, these are all Exhibits E-1 through -30, and these are the individual well curves for that field, and we probably don't need to go through all of them. We might look at a couple of significant ones.

If you turn to E-4, this is the Mark Federal Number 1; it's a Read and Stevens well. And you'll notice that the well's been producing now almost four years, and it's -- essentially the production is flat, other than a little dip at the very beginning where the well was down -- or it wasn't down, but the production was down while they were running rods and pumping the well. And it's back on production.

They did -- When we got our higher allowable approved last year, they did some testing on it and got a pretty good increase in the gas and decided, I guess, to pinch it back a little bit, so... But it's made over 100 barrels a day now for four years. And this is pretty typical of the better wells in the first sand; they're just really strong wells.

Unless Mr. Stogner would like to go through each curve, we can --

EXAMINER STOGNER: I think it's self-explanatory.

Q. (By Mr. Carr) Actually, Mr. Stubbs, if we stay on E-4, this well appears to be approaching the bubble point, does it not?

A. It has a GOR increase during 1994, and there's probably a localized area around that well, not necessarily the whole reservoir but just a localized area that is now at the bubble point, yes.

Q. Could you summarize the engineering conclusions you've been able to reach about at least the reservoir characteristics in the first sand?

A. Well, the first thing that we realize about the first sand is that it is not a typical Delaware reservoir. A typical Delaware reservoir usually exhibits about a 50-percent drop in production during the first year, and then it goes to about a 25-percent decline for the next couple of years.

These wells have not exhibited that. As you can see on the Mark Federal Number 1, we've got constant production of over 100 barrels a day.

So this brings us to think that there's something going on that's not typical. And one of the things that we think is going on is that we have a pretty strong water drive, and that's indicated by fairly stable pressures, a little bit of water increase in the wells to the south. And if you map that water leg, it extends for at least a mile on down into Sections 14 and 15. And it not only extends down there, but it thickens. So it's a relatively large water leg.

Q. Looking at the water drive, is this a bottom or an edge water drive?

A. It's an edge water drive, and the reason I think it's an edge water drive is the nature of the Delaware. You might turn back to the type curve under Tab 3.

If you will notice on the gamma ray, which is the far left curve, you've got quite a bit of spiking. Those are laminations, and it pretty well ties with the model. Those laminations are shale -- a lot of it is shale. Little thin laminations in those shale barriers don't have any vertical -- or very little vertical permeability, so that the only way the water can encroach is from the edge; it can't come through the bottom unless it's been hydraulically fractured through those shale streaks.

Q. At this point in time under the temporary rules, do you have an opinion as to how efficient the displacement of the oil has been in the reservoir?

A. I think it's been real efficient. Typically a Delaware well -- Delaware fields have recovery factors of around 10 or 12, maybe 15 percent. The third sand we've already recovered 10 percent, and we're still 700 barrels a day. It looks like we're going to recover in excess of 27 percent of the oil in place.

I see no reason to believe that it's not an efficient displacement. We're not seeing any kind of water problems, we're not seeing channeling or coning or anything like that.

Q. Let's go to Tab 6. Could you identify the first exhibit behind that tab?

A. Exhibit F-1 is a digital representation of the third sand, and essentially we did it the same way we did the first sand. We just took the porosity, the net feet, came up with a porosity-feet. And I used porosity-feet in the third sand because the water saturations are relatively constant over that sand, whereas in the first sand they vary, so we calculate in oil-feet and take into account the water saturation.

Q. All right. If we go to F-2 could you review the information on that portion of this exhibit?

A. Okay, F-2 is a calculation of the original oil in place using this digitized map.

We calculate that there's almost 5.5 million barrels of oil in place in the third sand.

We're estimating that the Armstrong wells are going to -- You can see up in the upper right-hand, "Recoverable", that recoverable reserves are anywhere from about 150,000 to over 300,000 barrels per well.

Q. And this page, this exhibit, just sets out the parameters in these calculations?

A. That's correct. This is the basic data we use to look at the third sand.

Q. How does this estimate compare to the estimates of recoverable oil presented in the earlier hearings in this reservoir?

A. Really, the only thing that's changed dramatically is that when we drilled the Number 5 well, we had this mapped as that finger that the Armstrong wells are in, extended north, and the original reservoir volume was over 7 million barrels.

But when we drilled the Number 5 well, pulled the northern boundary down and cut off what we had projected up into the northwest quarter of Section 2. So it just pulled the northern boundary down, and now we have a volume of about 5.5 million barrels.

Q. Okay, let's go now to Exhibit F-3. Can you identify and review that?

A. Okay, this is a similar map that we had in the first sand. It's looking straight down at the top of the reservoir.

You can see in the middle there the lighter area surrounded by a circle where the four Armstrong wells are. That's the highest or the biggest thickness of the sand in that third-sand reservoir.

There's a -- Exhibit D-4 [*sic*] is a side view, and you can see the relative size and shape of the reservoir.

And the reason it dips drastically to the south is, it's approaching the oil-water contact, and this is just the reservoir above the oil-water contact.

You also notice that on the left-hand side there's the nose that Mr. Boling was talking about, and that's pretty well supported by the production on those wells along that nose. It's also supported by thinner and tighter sections along that nose.

The Read and Stevens well on the far left, it has that other peak, is the -- Let's see, that's the North Lea Federal Number 6 well, and that's their best well in the third sand.

Q. Let's go to Exhibits F-5, F-6 and F-7, and I'd ask you to review the bubble plots on the third sand.

A. F-5 is the bubble plot of the oil production, and it shows that the Armstrong wells, which, the MLS 1, 2 3, and 4 in the middle there, have the highest cum in that part of the field.

The Mark Federal 8, Mark Federal 4 and the

Northeast Lea Federal 10 follow along that nose, and you'll notice that they have poorer production than the other wells in the field.

Then the North Lea Federal Number 6 on the far left side is the best producer in that far west finger of the third sand.

And the West Pearl State 2 and 1 are kind of in that far northeast neck, and they're somewhat limited up there. It's different reservoir quality.

Q. All right. Now, let's go to the next page and look at the gas production.

A. Okay, the major gas production is coming from the Armstrong wells in the middle of the field. One thing that we think supports the encroachment of water, or water influx into the reservoir, is the low GORs in the south end of the field.

We'll look at a curve in a minute, but the North Lea Federal Number 6 and 10 are still just about the original GOR.

Q. And now F-7?

A. And F-7 is a bubble plot of the water production. The wells that have the highest water production are in the south end of the field closest to the oil-water contact.

The North Lea Federal Number 6 has produced the most water of any well in the third sand, and it's done that, I think, for two reasons. It's always had a fairly high water cut, and we think that's partly due to the stimulation treatment, went a little out of zone, so we picked up some of the lower stuff that was wet.

And the North Lea Federal Number 10 is just -- it's probably the -- it's the lowest well in the third sand, it's closest to the oil-water contact. And it's had an increasing water cut through its life.

Q. Mr. Stubbs, let's go back for a minute to the first page behind Tab 6, Exhibit F-1.

A. Okay.

Q. What we have here is not a typical Delaware reservoir; is that correct?

A. That's correct, the majority of Delaware reservoirs are solution gas drive with very little influence from water influx.

And we also have much higher permeabilities and porosities and deliverabilities than a typical Delaware well.

Q. You're seeing, in essence, really a strong edge water drive in portions of the reservoir --

A. Right.

Q. -- is that correct?

A. That's correct, and that's --

Q. And low production rates?

A. High production rates.
Q. High production rates.
Could you, using this exhibit, just summarize for the Examiner basically how you see the mechanics or the methodology of most effectively producing this particular interval in the Delaware?
A. Early on, when we first started looking at the Number 1 well, it became pretty obvious that we didn't have a normal Delaware well, and we realized that by the production rates and the pressures. We did different rates up to 300 barrels a day, and we'd slow it back down, and the pressures would just come right back to where they were originally.
And the wells kept doing that, even through the first year. You would slow them down, and the pressures would come right back up to where the original pressures were.
So we felt like we had something going on that we didn't quite understand or wasn't typical, and we got to looking at it and found the water leg and mapped the water leg, and it's similar to the first sand water leg, as it thickens and extends at least a mile to the south.
So the water leg is considerably bigger than the oil leg. So that gave us a pretty good clue that we've got some water influx, water is probably helping to maintain

the pressure in the reservoir.

And that led us to two concerns.

Number one, first concern, was, if that's the case, then this is going to be a fairly steady producer for a number of years, it will be a long time before we ever get to the first sand.

Number two, if we don't draw down the pressure and allow the oil along the updip edge, the northern edge of the reservoir against the facies change, if we don't draw down the pressure and allow that oil to expand and get some help from the gas to move that oil down from the updip position, we're probably not going to recover as much oil as we could from the updip edge.

So that was our two concerns, and that's why we came to the Commission and asked for higher allowables, so we could manage this reservoir and recover that updip oil by reducing the pressure, allowing the gas expansion to move that oil downdip.

And then later on, as the water influx comes in from the south, we'll push the downdip oil up to the producers.

So we think that will maximize the recovery from the third sand, and the higher allowables will allow us to now go and open up the first sands.

Q. So we've really got three things:

We've got the water influx or drive from the southern portion of the reservoir?

A. Right.

Q. Pressure drawdown from the northern end of the reservoir?

A. Right.

Q. And then trying to maintain the middle of the field or the central portion of the field at a pressure somewhat close to the bubble point?

A. That's the management plan that we've decided to take, is to monitor the pressure mid-field, keep the south half of the reservoir at or above bubble point so we don't liberate any free gas, and then draw the pressure down on the north end of the field and get as much help from gas expansion and maybe even a gas cap pushing oil downdip to us.

Q. Let's go to Exhibit F-8. Could you identify and review that, please?

A. F-8 is a summary production curve for the third-sand wells. Presently the third-sand wells are producing about 22,000 barrels a month.

They have produced as high as 35,000 barrels a month, and that was three months starting in March, April and May of 1994, where we had the increased allowable, and we increased the allowable. During that time we saw an increase in the GOR, which was what we hoped to see.

Once we got the GOR increasing, we decreased production and we started running pressure tests in May of 1994.

Q. Basically, what does this show? That you've been successful in lowering pressure in the northern portion of the field?

A. That's what we believe has happened. We've lowered the pressure below the bubble point, and we've liberated some free gas.

You'll also notice that the water production, which is the little triangles, has really shown no increase or very little increase fieldwide, and there's -- We'll show one case in just a minute where we have a little -- some increase on the North Lea Federal Number 10 well.

But fieldwide, the water production really hasn't increased.

Q. All right, let's go to the information behind Tab Number 7, the individual well curves. And again, I don't know if you want to review all of these for the Examiner, but you might at least start with the first graphs on the Armstrong Mobil Lea State Number 1.

A. Okay, the Mobil Lea State Number 1, some significant things on it is, again in March, April and May of 1994, with the higher temporary allowables, we increased production, saw the GOR increase.

You'll also notice on that particular well -- The little triangles again is the water production. We really have a decrease in water production on that well, and that's just removal of the mobile water, what mobile water was in the reservoir, and we really aren't seeing any kind of water breakthrough on that particular well.

Q. Let's go to --

A. Just one more thing.

Q. All right.

A. You'll notice that the GOR presently is about 2000 to 1, and the last month or so it's just slightly over 2000 to 1, and that's one reason we're requesting a little higher gas allowable, is we expect it to increase a little over 2000 to 1 and then start coming back down.

So we need a little more room to continue drawing that north part of the reservoir down.

Q. What does the graph on the bottom of this page indicate or show you?

A. That's just showing oil and water cut. The little diamonds is the oil cut, presently is around 90 percent. The little squares is the water cut. It's about 10 percent. And it's been fairly constant through the whole life of the well.

Q. Let's go to the last page behind Tab 7, marked

Exhibit G-10.

A. This is the North Lea Federal Number 1 well we talked about a minute ago. It's the lowest downdip well in the third sand.

And you'll notice that the water cut has shown kind of a steady increase. It started at about 2000 barrels a month, and it's about 4000 barrels a month now. And this is partly due to the location close to the oil-water contact, plus the water influx coming from the water drive is probably finally getting to this well.

We'll talk about it a little later on, but the voidage out of that finger as the water increases are occurring just about like we predicted they would, so we don't feel like we're getting any serious channeling or coning or cusping into the well. We're getting pretty efficient, good displacement by the water drive.

Q. All right, let's go to the material behind Tab H and review first Exhibit H-1.

A. Okay, in our management plan we decided to start taking pressure measurements in the field or in the third-sand reservoir to substantiate what we thought was going on.

The first one we did at the end of May of 1994, and it was on the Mobil Lea State Number 1 well, and it's the one up in the -- kind of the far northeast corner of the third sand -- the main third sandbody. And we found at that time that the reservoir pressure was about 930 pounds.

A couple interesting things, I should have showed it on here but I didn't. You'll notice that the end of the buildup kind of flattens out. We feel that that's probably due to interference. We had the other three wells producing.

During that buildup period, though, we did a couple of things just to kind of get an idea of what was communicating with what.

We shut in the Number 2 well for a little while, like eight hours, and we immediately saw a little bump on the buildup curve. And as luck would have it, a lightning storm came through there and shut the whole field down for a couple hours, and we got another bump.

So we feel like everything is pretty well communicated in the field -- or in that third sand.

Q. All right, this is the first of the four tests. Let's go to H-2, and I'd ask you to review the next pressure test.

A. Okay, we selected the Mobil Lea State 3 well kind of as a control well, and it's in the middle of the third-sand reservoir. And we felt if we kept the reservoir pressure in that well at around 1300 pounds or right above the bubble point, and kept the pressure north of there below the bubble point, that we would accomplish what we set out to do.

This test was run the end of June, and the extrapolated pressure is about 1300 pounds. We had a fairly extended shut-in time on that well, and we -- One thing we found, that we had a nice change of slope, which indicated some kind of barrier. We did a real quickie calculation using kind of an average permeability, and it indicates about 700 feet away, which would probably be the limestone facies change to the northwest.

So that pretty well confirmed the geometry of the reservoir.

Q. What is the bubble point in the reservoir?

A. The bubble point appears to be about 1200 pounds, and that's from what we see on the well tests and that's also from correlation charts.

Q. And the pressure information on this second test, on the Mobil Lea State Number 3, basically, that test information confirmed the northern porosity pinchout of the reservoir?

A. Right. You know, we picked that barrier up, and if you -- We just used a gross interval to calculate that. If you used a little smaller net-height, net interval, it would extend that on out to about 900 or 1000 feet, and that's right where the barrier is. So we feel pretty comfortable with that.

Q. What is shown on Exhibit H-3?

A. H-3 is just the calculation to find the radius of that barrier.

Q. Let's go on to H-4 and review the information on the third well, pressure test.

A. Okay, we waited about three months and ran another pressure test on the Mobil Lea State 3, and this is after we had lowered the production rates a little bit.

And we found that we still were at about 1275 pounds pressure in that area, and that's within the range that we wanted to stay in. And it was a fairly short test, so we didn't pick up that barrier again.

The rest of these are fairly short tests.

Q. This well, was this actually in the southern portion of the field?

A. It's mid-field.

Q. And does this pressure test show anything concerning the water influx into the reservoir?

A. Well, what it does is, during that three-month period the pressures have stayed relatively the same, so that leads us -- that confirms that we're getting help from the water to the south, that we're getting influx that's keeping the pressures up.

Q. All right, let's go to Exhibit H-5.

A. H-5 is another test we did the end of November, and it looks kind of funny, and I really can't explain why it looks funny.

When we first started the test we had a little over 1000 pounds pressure. It kind of felt like the well had either been down or something had happened to it, because it shouldn't have had that high an initial pressure.

And then partway through the test we got a burp or a gurgle, and it built up about 300 pounds in just a few hours. So there was a slug of fluid or something in the well that caused that pressure increase.

But if you take the last few points and extrapolate them, it come out somewhere around 1400 pounds.

So we're still -- in fact, we're even gaining -- It indicates we're even gaining a little pressure. The last test was 1275, and now we're closer to 1400. So we really picked up a little pressure.

Q. When was this test run?

A. This was run at the end of November.

Q. Okay, and let's go to page H-6, the next page. This is another test in the same well, is it not?

A. Yeah, this is the same well, same procedure. This test was run in January of 1995, and it indicates that we're still above 1200 pounds at the mid-field point.

Q. All right. Then the last graph, what does this show?

A. This is just a summary of the plots versus the cum of the Number 3 well. Initial pressure was slightly over 2500 pounds at zero production, and the four points that we measured in the last nine months or so starts at 40,000 and goes to almost 60,000 barrels cum, and we've maintained about 1200 to 1300 pounds reservoir pressure mid-field.

Q. What is Exhibit H-8?

A. H-8 is a visualization of what we think the pressure gradient across the field is right now. On the upper part of the page, which is kind of turned around so you can see it better, is the south end of the field, the darker area.

Because we don't see much increase in the GORs and we feel like the water leg is still above 2000 pounds reservoir pressure, then we've drawn down the pressure on the wells on the north end of the field, the pressure gradient goes from above 2000 now down to like 600 pounds around the Mobil Lea State wells on the north end.

Q. Let's go on to H-9, and I'd ask you to review the material balance information.

A. Okay, now we've determined a reservoir volume, we have an extended production history, and we have some pressure data. We use a material balance equation to account for the amount of fluids taken out, the pressures and the amount of fluids that have entered the reservoir.

Through this analysis, if you'll turn to H-11, if we match the production and we match the pressure, we find that at the end of last year we had about 436,000 barrels of water influx, is needed to maintain that mid-field pressure of about around 1200, 1300 pounds.

At this point we're probably seeing at least a thousand barrels a day influx into the reservoir, so we're probably well over half a million barrels of influx.

Q. Okay, and let's go to H-12. What does that show?

A. Okay, H-12 is an exhibit showing where we think the water influx is right now, and it's based on the withdrawal from those two fingers.

The finger in the middle, which is where the Armstrong wells are, has the largest withdrawal, and you'll notice that the light shading goes up to about two lines below the Mobil Lea State 3 and 4, so it's -- the water influx, if it's calculated correctly, still quite a ways away from the Mobil Lea State wells.

The original oil-water contact was at minus 2275. The two Read and Stevens wells in the far west finger, the voidage in the water influx indicates that the water should just about be reaching those two wells, and we're seeing that in the North Lea Federal Number 10, we're seeing an increase in water. So that pretty well matches what we've calculated.

Q. What conclusions have you been able to reach from your geologic -- or engineering study of the reservoir?

A. Well, the first thing is, it's not a typical Delaware reservoir. It has a strong water drive, it has excellent permeabilities, and we should have recoveries in excess of 27 percent, maybe even over 30 percent on the third sand, due to that water drive.

Q. Now you're seeking adoption of permanent rules, including a 300-barrel-per-day allowable?

A. Yes.

Q. You're also seeking an increase in the gas-oil ratio to 3000?

A. That's correct.

Q. Is this necessary if you are able to produce this reservoir at its maximum efficient rate?

A. Yes, we've determined that the maximum efficient rate is a rate that we can maintain mid-field pressure of around 1300 pounds, and that means that we need to produce these wells like they're currently being produced, at around 100 barrels a day.

And we expect that production rate to be fairly constant. We hope it is, anyway.

Q. Without this higher allowable or production rate, in your opinion, is it possible to adequately manage this reservoir to maximize the ultimate recovery therefrom?

A. No, because we really need the flexibility to draw that pressure down and allow the gas to help us recover that updip oil, gas expansion to help us recover that updip oil.

Q. Have you been able to quantify the production -- the oil production that might be lost if in fact the Application is denied?

A. Yes, there's about 200,000 barrels of recoverable oil in that updip position.

Q. What might happen in this reservoir -- or do you foresee happening, as the water moves through it? Are you going to have any erratic changes in the recovery from the wells?

A. Well, the way it's acting right now is, we're not seeing any drastic increases in water production, so it should be just a gradual increase in the water cut as the water pushes the oil updip to the producers.

Q. If this Application is granted, will any operator be denied the opportunity to produce his fair share of the reserves in the reservoir?

A. No. In fact, it will help the operators produce their fair share.

Q. If in fact the rules were to revert to the statewide rule, would certain operators be, in your opinion, subject to drainage in the various Delaware zones that are productive in this reservoir?

A. It's my opinion that all the operators would be subject to drainage, and I'll give you a couple examples.

Like -- Armstrong has the third sand. We anticipate 100-barrel-a-day production per well for an extended period of time. They're not able to, at this point in time, come up and complete in the first sand.

Read and Stevens has a similar situation in their side of the field. Most of their wells are in the first sand. They've just tested a zone in a deeper horizon that will also make allowable, so they have the same situation. They're going to have first-sand wells and deeper horizons that are going to be capable of 100-barrel-a-day-plus production rates, and they're only going to be able to produce one of those at a time, essentially.

I think Mallon has the same situation in their field, just looking at their logs. They have three or four sands that are -- look comparable to the first and third sands, and they have the same situation. They're only going to be able to complete one at a time.

So if you have a situation where one operator has one sand open and another operator has another sand open, one operator is draining somebody else's lease or this operator is draining on the other lease.

So it really needs a higher allowable so everybody can complete their wells and manage the reservoir properly.

Q. Waste is going to be prevented by granting the Application?

A. That's correct.

Q. Correlative rights will be protected by granting the Application?

A. That's correct.

Q. And the granting of the higher allowables, in the bottom line, is going to enable operators in the field to best manage the reservoir to maximize the ultimate recovery from the reservoir?

A. That is correct.

Q. We're talking about being able to produce in zones that without the allowable are going to be shut in and subject to drainage; isn't that right?

A. That is correct.

Q. We're also talking about general considerations within the individual zones.

If, for example, in the third zone water moves from the south toward the north and starts sweeping production in that direction, wells in the northern portion of this zone might also need the higher allowables, simply to recover the oil that's being swept toward them; is that not correct?

A. Yeah, that's possible. As that oil bank moves to the north, you may need a higher allowable to keep the pressures in the range you want to keep them in.

Q. In your opinion, will approval of this Application be in the best interest of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes, it is.

Q. Was Exhibit 8 prepared by you?

A. Yes, sir.

MR. CARR: At this time I move the admission of Armstrong Exhibit Number 8.

EXAMINER STOGNER: Exhibit Number 8 will be admitted into evidence at this time.

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

EXAMINER STOGNER: Thank you, Mr. Carr.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Stubbs, as a reservoir engineer you have examined the reservoir parameters for the first sand, have you not, sir?

A. That's correct.

Q. And you have looked at the reservoir parameters for the third sand?

A. That's correct.

Q. Do you find, in your judgment, any material difference between those parameters that is of significance to you?

A. The first sand may have just a little less permeability than the third sand. But other than that, they're very, very similar.

Q. In order to maximize recovery from both of those intervals, do you see any reason to try to produce them separately?

A. No, as far as I can tell there's nothing that would interfere with producing them separately -- or producing them together, combined.

Q. In response to Mr. Carr a while ago, you put a 200,000-barrel-of-oil number and said that represented oil that might not be recovered if the pool was required to go back to 107-barrels-of-oil-a-day allowable?

A. That's correct.

Q. To what zone did you attribute the 200,000 barrels?

A. That's out of the third sand.

Q. Out of only the third sand?

A. Right.

Q. Describe for me how you came to that conclusion.

A. We have in the -- in the third sand we have -- It slopes about 2 or 2 1/2 degrees to the south, so that gives you an updip position. The Armstrong wells are probably 600, 700 feet away from that updip position.

So if the pressure in the reservoir remains high, this oil up here has no way to get out of the reservoir, really. So you need to draw the pressure down so the reservoir compressibility and expansion of the gas will cause that oil to expand and actually push it downdip.

Now, you get some gravity drainage, but it's much more efficient, I think, to go ahead and let that expand and push that downdip oil down to the producers.

Q. Within the context of the pool boundary, where is that attic oil currently stored?

A. Well, it's -- runs along the north part of the -- well, let's see, the north part of the -- Find out where I'm at exactly. The north part of the south half of Section 2 is where most of it lies, if you'll turn to Exhibit H-12.

Q. All right, sir, and I was trying to get a visual reference. If we look at Mr. Boling's Exhibit Number 6 --

let me hand that to you, sir -- perhaps you can give us a visual reference of what you're talking about.

A. That would be the part of the reservoir north of the wells marked 98 and 86, which is the Mobil Lea State 1 and 2 wells.

Q. Can you get that attic oil by drilling additional wells?

A. We drilled -- In my opinion, it would be wasteful to drill another well. We drilled the Number 5 well and identified the northern boundary, and the Number 5 well is about 800 feet north of the Mobil Lea State Number 2 well, and we feel like we're right on the edge of the porosity change or the lithology change, so --

Q. So in your opinion, if you wanted to spend the money, the chance of successfully recovering the attic oil with additional new wells is pretty risky?

A. Well, you could recover it, but it would really be too close a spacing to make it economically feasible.

Q. So the best way to achieve the recovery of that additional 200,000 barrels of oil that's at risk of being lost is to keep the oil-allowable rate higher and let that gas cap expand in the third zone so you recover it with existing wells?

A. That's correct.

Q. Is that situation in place for the first sand?

A. We haven't really identified a place where that occurs in the first sand, but at some point you're going to have a lithology change and a barrier. And you could have that same situation in the third sand, but we haven't identified that yet. We haven't really found the northern edge of the third -- or the first sand.

Q. What's the basis for selecting 300 barrels a day, as opposed to some other rate?

A. Well, our original thinking was that we'd like to have about 200 barrels a day to manage the third sand, and we'd need at least another hundred barrels a day to be able to produce -- complete and produce the first sands. So that's kind of where that number came from.

Q. And you've had a year to work with that allowable level, and what level of success have you achieved at that rate?

A. Well, I feel like we've been very successful in the third sand. You know, that's what we've been concentrating on the last year, trying to figure out what was going on in the third sand. I think we have a pretty good handle on that now.

Now we're ready to come up and start completing the first-sand wells. We did the first well, which is the West Pearl State Number 2. We're now working on a completion procedure for the Mobil Lea State Number 2.

Q. Representatives of Read and Stevens are not here today, Mr. Stubbs. I assume you know those people?

A. Yes, I do.

Q. Have you been in discussions with their engineering personnel?

A. I haven't in the last couple months, but it's my feeling that they're happy with the way things are right now.

Q. All right. With regards to this Application, you're not aware of any opposition on their part to keeping these rules the same for the oil rate?

A. No, as far as I can tell they're satisfied, and I think they've figured out that what we presented at the original hearing is the way it's finally turning out, and I don't think they're opposed to it, no.

Q. Other than Armstrong and Mallon and Read and Stevens, are there any other operators in the pool?

A. Well, there's the Mid-Continent well, which is on the far eastern side, and it's a first-sand well, and it's just about depleted.

There's three other fairly insignificant wells on the far west side, Snow Oil and Gas, and they're just marginal wells. They're right on the edge of the reservoir.

Let's see, if you want to turn back to under Tab

4, Exhibit D-4, the wells on the far west side, the PF Number 1, the SCJ Number 1, and then down at the bottom, the UAF Number 2, you can tell that those wells pretty well define the western edge of the reservoir. They're just real poor producers, they're thin, poor reservoir quality.

Q. At this point the best you know is, all the operators support the proposition that the 300 barrels of oil a day be made permanent and that the GOR be increased to 3000 to 1?

A. Right.

Q. Are you responsible in any way for the frac treatments on your wells?

A. Yeah, I guess. I work with their production superintendent a little bit on, you know, how we want to frac them and the parameters and --

Q. Mr. Boling has identified, at least geologically, that the first and the second and the third and perhaps the fourth are all separated?

A. That's correct.

Q. How has the integrity of that separation been maintained with the existence of frac'ing these wells?

A. Well, for instance, the first and third sand, they're separated by --

Q. -- the second?

A. -- the second sand. If you want to turn back --

Q. And the second is usually a water-producing sand?
A. Yeah, it's a little over 100 feet thick.
And typically, we give ourselves a little room and not perforate the lowest part of the zone; perforate a little higher above.
You know what I mean. You have a zone, you may put your perforations 20 or 30 feet above the bottom part of it, thinking that it's going to frac that whole interval, but you don't want to start right at it because it will frac down through.
Q. In your part of the reservoir with your wells have you been successful in confining the fracture treatments to an individual interval?
A. Yeah, we feel like we have, just because we don't have any water production.
Now, there's some of the wells -- Read and Stevens has a few wells that we feel like are frac'd out of zone because they do show -- do exhibit high water production.
And we don't put real big treatments on there, really. You know, 20,000 gallons or something. So we don't get a lot of frac height.
Q. Do you see any reason not to communicate all those zones in the wellbore?
A. Well, in our case, in our part of the reservoir,

there's a reason because you don't want the second sand.

Q. Because it's got so much water?

A. Because it's got so much water. So you want to do them separately.

If you had all three sands open I think you'd just about have to complete them, because by the time you -- If you frac one and you're going to frac the second one, it's probably going to communicate, because there are going to be differential pressures.

So you really, probably -- If you have all three sands or a large interval that's all full of oil, I think you'd be better off doing it all at one time, or you'd never get it all treated. I don't think you'd ever get it treated.

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER STOGNER: Mr. Kellahin.

Mr. Carr, any redirect?

MR. CARR: No, sir.

EXAMINATION

BY EXAMINER STOGNER:

Q. No indication of water coning?

A. I haven't seen anything yet. Like I said, the North Lea Federal Number 10 is the lowest downdip well, and if there was any significant coning or cusping we probably would have watered that well out a long time ago. And it's just shown a real gradual increase, and it's pretty well as we predicted it. And all the rest of the wells -- a lot of the wells are even showing declines in water production, producing the mobile water.

Q. Have you had an opportunity to review, other than I believe you said the Number 12 well in Section 34, some of the reservoir characteristics of that new extension to this pool up in the east half of 34?

A. No, that data just hasn't been available because they're only a couple months old. But we did get a copy of the log on the Number 12 well. It looks surprisingly similar to what we're looking at down in Sections 2 and 3 and 10.

Q. You don't know what -- if that's either coming from the first or the third sand production?

A. Well, let's see here. We've got a little bit of data. I pulled out some of the cards.

The Mallon Number 2-34, is perforated 5878 to 5946. It IP'd for 192 barrels a day. That's real close to what we call the third sand.

Then the Mallon Number 3 well, and it was IP'd right at the end of November, and it's perforated 5842 to 5882, IP'd for 254 barrels a day. That's probably -- and I'm just guessing, because I haven't really had a chance to correlate it all. That's somewhere between the second and first sand probably, probably above the third sand.

Q. How about the Number 12?

A. I don't -- It was drilled, I think, right after the first of February, it was finished drilling, so I don't know that they've even had a chance -- maybe Mr. -- maybe Ray can -- Ray Jones can expound on that a little bit, because I just don't have any data other than the logs.

EXAMINER STOGNER: Mr. Kellahin, do you plan to put on a witness today?

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: You do?

MR. KELLAHIN: Yeah.

EXAMINER STOGNER: I'll tell you what. With that, I don't have any other questions of Mr. Stubbs. He may be excused.

Let's take about ten, fifteen minutes at this time.

(Thereupon, a recess was taken at 10:30 a.m.)

(The following proceedings had at 10:55 a.m.)

EXAMINER STOGNER: Hearing will come to order.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner. I'd like to call to the stand Mr. Ray Jones. Mr. Jones is a reservoir engineer. He's also the vice president in charge of engineering for Mallon Oil Company and resides in

Denver, Colorado.

EXAMINER STOGNER: Mr. Jones, did we swear you in earlier?

MR. JONES: Yes.

MR. KELLAHIN: Yes, sir, you did.

EXAMINER STOGNER: Okay.

RAY E. JONES,

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

EXAMINATION

BY MR. KELLAHIN:

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

A. Ray E. Jones, and I am a petroleum engineer.

Q. On prior occasions have you testified in that capacity before this Division?

A. I have.

Q. Summarize for us your education.

A. I have a bachelor's of engineering degree from the Colorado School of Mines, 1979.

Q. And your current position with your company is what, sir?

A. Vice president of engineering.

Q. As part of your duties, have you been responsible for the reservoir engineering as well as the operational engineering aspects for the Mallon-operated wells that are being drilled and some of which are currently capable of production in what is called the Northeast Lea-Delaware Pool?

A. That is correct.

Q. Based upon that capacity and your reservoir engineering studies, do you have certain opinions and conclusions as well as engineering recommendations for the Examiner?

A. I do.

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

EXAMINER STOGNER: Are there any objections?

MR. CARR: No objection.

EXAMINER STOGNER: Mr. Jones is so qualified.

Q. (By Mr. Kellahin) Mr. Jones, you have prepared for the Examiner and we have submitted to him what we've marked as Mallon Exhibit 1. That package is numbered consecutively, starting on pages 1 through page 10.

Let me ask you to turn to page number 1, and let's have you summarize for us what Mallon's position is concerning this case.

A. All right. Mallon Oil Company supports continuation of the current 300-barrel-a-day allowable for the Lea Northeast-Delaware Pool, and we support making that allowable permanent and --

Q. What are the principal reasons that you have for making that recommendation?

A. We have drilled five -- excuse me, currently four Delaware wells. Those wells have rather thick Delaware sands; they're multiple sands.

We are concerned about the completion techniques in completing the wells and being able to produce the reserves that we see at this time in those sands, and we feel that the 300-barrel-a-day allowable would allow us to more effectively complete the wells and more effectively recover the reserves than the 107-barrel-a-day statewide allowable.

Q. All right. Let's take a well as an example and identify the well and then tell us what a current rate is for that well.

A. Well, page 2 of the exhibit is a locator map.

Q. All right, sir, let's look at page 2. The wells in Sections 34 and 35, some of those are operated by you?

A. That is correct, we operate the well in the southeast of the southeast of 35, and we operate the wells in Section 34.

Q. All right. Let's look in Section 34 and have you pick us an example well for us to have a short discussion.

A. Let's take the well in the northeast of the southeast of Section 34, the Mallon 34 Federal Number 3.

Q. All right, that's currently perforated in only one of these Delaware intervals, is it not?

A. That is correct.

Q. And at what rate do you currently produce that on a daily basis?

A. 100 to 105 barrels a day.

Q. If you added additional intervals, would your ability to produce that well exceed the allowable on statewide rules of 107 barrels a day?

A. Yes, it would.

Q. In fact, its current rate exceeds that?

A. Is that, yes.

Q. All right. As part of your conclusions and recommendations on page 1 you say, "As not all sands are produced at lower allowables, inequities will occur."

A. That is correct.

Q. Describe for us what you mean.

A. There is a variation in sand quality that we've observed to date, and at a low allowable you would expect the highest productive zone to produce the most or potentially all of the oil.

Not all wells at this time are completed in all sands, and we have different working interests amongst the wells.

Q. Even those wells that you operate have a different working interest?

A. That is correct. And so there could be some drainage in the individual zones by wells, because not all wells are producing in the same number of zones or the same zones.

Q. If we maintain the 300-barrels-of-oil-a-day allowable rate on a permanent basis, does that more equitably distribute the opportunity between the 40-acre spacing units to compete for recovery of oil from the Delaware?

A. Very definitely.

Q. The second item on your page 1 as a reason for making the rules permanent deals with the fracture procedure for your wells. Describe for us what you've said and then what you mean by this paragraph.

You say, "All production sands should be frac'd initially to treat all zones. Waiting until one zone is depleted before treating remaining zones will result in other zones not being treated."

A. That is correct. We have a very large concern that the Delaware sands will frac together, at least initially, to initiate the frac. That has been the common experience in the Delaware and other areas, and it has been published in the literature.

Q. You've already experienced that in your section, have you not?

A. Yes, we have, and in other Delaware fields that we operate.

If one sand is completed and produced until that zone is depleted, and then you come back in to complete another sand, the zone that is depleted will preferentially take the next fracture treatment. So it may not be possible, then, to actually treat effectively the other zones and then produce those reserves.

Q. Why does that happen?

A. Because in order to -- as part of the fracture extension mathematics, it's a function of the reservoir pressure. As you lower the reservoir pressure, it is easier to extend the fracture in that section.

If you have not produced these zones, reservoir pressure would be at initial conditions, and it would be more difficult to create or extend a fracture in those zones, compared to the zone that has been depleted.

Q. What does maintaining the oil allowable at 300 barrels a day allow you to do to overcome that problem?

A. That would allow us to complete all zones and then produce all zones more equitably, and then tighter zones would have a better -- or would be able to be frac'd and cleaned up initially and then would contribute more of the ultimate recovery from those zones than if you had a lower allowable.

Q. How would a higher rate allow you to achieve a more effective cleanup of the zones?

A. There are some sands in our wells that will exceed on their own the 107-barrel-a-day statewide allowable.

Without producing the well at a higher rate you could not be sure that you've effectively cleaned up a zone and actually have production from other zones.

So you could treat the zone but not clean it up and not end up with an effective fracture treatment.

Q. Why couldn't you go ahead and, for example, frac -- isolate and frac the first sand, produce that to depletion, go back and squeeze that off, isolate and frac the second sand, if you will, frac that and produce it to depletion? Why can't you do these consecutively?

A. We're not able to isolate the fracture treatments in the reservoir, because back to the experience in the Delaware where fracture treating extends for large distances vertically, and even though you could isolate it at the wellbore, or potentially isolate it at the wellbore, you cannot isolate it at the reservoir.

We've got some examples where we've been unable to contain a fracture treatment within one specific zone.

Q. Let's go to that discussion now. If you'll turn to the cross-section, which is Mallon Exhibit 2, identify for us the wells on the cross-section, and then let's find the log for the well that illustrates this point.

A. In the lower right-hand corner of the exhibit there's a locator map. It's marked -- The cross-section goes from A' to A, and we're looking westerly, so north is on the right-hand side of the map.

Q. All right. Rather than talk about all of these wells, let's find one that illustrates for us this problem about confining the fracture treatment to a particular interval.

A. All right. Well, let's begin with the Mallon 34 Federal Number 3. That is the second from the left.

What is shown here is a strip of porosity log, and next to it is a gamma-ray log. We -- And on the gamma-ray log, you can see the interval that was perforated. That was the lowest sand member in this well.

The proppant was tagged with a radioactive tracer. We frac'd the well, cleaned it up, came back in and logged it. And as you can see from the high gamma-ray readings on the after-frac log, although we had only perforated -- top of the perforations was approximately 5840, proppant was put up as high as 5800. And so the interval between 5810 and 5835 did not serve as a barrier for this fracture treatment.

So what we're left with is an ineffective treatment of the next sand up. However, we already have communication with the fracture between the two lower sands, and any effort to treat the sand at approximately 5800 feet is obviously in communication with the prior treatment of the lower sand.

Q. Why don't you just redesign your frac treatments so that you maintain a shorter frac length and keep it within the interval you're trying to frac?

A. The -- We believe a large frac volume, large frac sand volume, is necessary to maximize recovery from the sands. Some of the sands are tighter, lower permeability. All the sands require fracture stimulation to produce, and so the large frac treatments are necessary to effectively produce those reserves.

Simply making the frac sizes smaller will not necessarily prevent this breakthrough communication, as has been observed in other Delaware fields.

Q. Let's turn to page 6 of Exhibit Number 1 and talk about the permeability in the reservoir.

When you look at page 6 of Exhibit 1, that plot is generated based upon core analysis; is it not?

A. Yes, these are air-permeability measurements of sidewall core samples of Delaware sands for these wells, for the -- for three wells shown on the -- excuse me, for four wells shown on the locator map. That includes -- The heading shows only three wells. The heading shows Mallon 34 Federal Number 2, 3 and 12. We did encounter some thin Delaware in the Number 1 well, but that one wasn't produced.

Q. After you've plotted all of this information of permeability versus porosity on page 6, have it make sense for us, describe for us what it shows to you.

A. Well, we have a typical porosity-permeability relationship with increasing permeability with porosity. You can see that there's a spread of -- a range of permeability, perhaps from 1 to 10 millidarcies, that encompasses from 12- to almost 17-percent porosity, and those would be the intervals that we currently believe would be productive in this field.

What then applies is that the better sands would be expected to have permeabilities in the range of 10 millidarcies from this plot, and the poorer sands would be in the range of 1 to 5 millidarcies on this plot.

And so there's a -- will be a different productive capacity from sands of equal thickness because of this permeability variation.

Q. How does this wide range of permeability variation complicate your ability to specifically design a frac job that would stay within a particular interval?

A. Well, the problem with the permeability variation is that we believe that there are reserves in the tighter zones.

If you have a -- say a two-zone example, if you have a high permeability zone and then a lower permeability zone, both frac'd, frac'd together, and then under production, the higher productivity zone will produce the majority of the fluid.

If you had a 107-barrel-a-day statewide allowable, that higher productive zone may meet that allowable, and then you're not necessarily cleaning up or producing from the tighter zone.

Q. When we turn to page 3 of Exhibit 1, what are you representing on that page?

A. That's simply a plot of the production for the Number 2 well, showing variations in rate and some decline. It shows the water-oil ratio, which has been approximately one and a half barrels of water per barrel of oil.

This well has stabilized in the range of about 35 barrels a day.

Q. Any conclusions as an engineer that you can draw from this information?

A. This well is producing from Delaware sands that are probably more typical of other areas. It is not as productive or prolific as wells to the south. It's a well that obviously needs to be stimulated to produce.

Q. Okay, let's turn to page 4 and look at the Mallon Federal 34-3, again a production plot of production from this well.

A. Right, oil rate and water-oil ratio. In this case the water-oil ratio is lower, approximately .3 to .4 barrels of water per barrel of oil. This well appears to have stabilized off at about 100, 105 barrels a day. It's been on production for just less than four months.

Q. What significance does this information have for us today?

A. Well, the current production indicates that with the statewide allowable, we are at the maximum production rate, and adding additional zones would not increase the current production from the well.

And also, it's a very short time to evaluate this reservoir at this time.

Q. All right, sir. Let's turn to page 5. Identify and describe what you're showing here.

A. Page 5 is an example of the magnitude of reserves that we may have for these different Delaware sands. I included the Mallon 34 Federal Number 3 and the Mallon 34 Federal Number 12 as examples.

The zonation is the zonation developed by the

Mallon geologist and is not based upon the zonations that we've heard previously. The zones are ordered top to bottom for each well.

We have the average porosity for the intervals, a net thickness, water saturation. I've calculated the original oil in place. In that calculation I assumed a formation volume factor of 1.15 calculation.

I've shown a recovery factor, I've varied the recovery factor to try to account for variations in porosity and water saturation to go along with rock quality. They are, I feel, reasonable for this kind of rock type.

Q. All right. With that information, then, what's the point?

A. The overall purpose of this exhibit was to show that there can be significant -- there are significant reserves in the various sands in these wells and that ineffective production, ineffective completion of any one sand member can result in loss of significant reserves per well.

And then it also shows for the Mallon 34 Federal Number 3, we have three zones identified that we would want to produce from, you'd want to complete and produce. Mallon 34 Federal Number 12, four sand zones were identified. And in the Mallon 34 Federal Number 12, the --

two of these zones separately, I would expect, would be able to exceed the statewide allowable for a significant period of time, thus impairing the ability to produce or recover reserves from the other two zones.

Q. Mr. Jones, have you made a technical literature search for published papers on the subject of frac treatments in the Delaware and how to best maximize oil recovery from the Delaware with designing executing and effective and efficient fracture treatment programs?

A. Yes, we've evaluated that. I have included -- it's page 7 -- an excerpt from a paper, "A Review of New Techniques and Methods of Completing the Delaware Formation of Southeast New Mexico", by Vithal Pai and Morris Keith.

We have also used Vithal on designing our frac jobs in this part of the area.

I think the pertinent part of the area paper is the Summary Finding Number 1, "Most Delaware wells need to be fractured to be economical. They exhibit a tendency toward excessive fracture height growth which can be controlled using cluster perforations at the approximate center of porosity as opposed to blanket perforating the entire interval. This method also seems to reduce water production and post-frac proppant flowback problem. Proppant flowback can be further helped by tailing in with curable resin coated sand. The formation is sensitive to completion fluid formulation, therefore care should be taken in completion fluid design."

I think two pertinent parts of this that we have observed in our experience in these wells is that there is vertical fracture height growth in the Delaware when you frac it, and then there is a concern of adequate fracture cleanup after the fracture treatment so that you don't damage the reservoir near the fracture and that you can then effectively -- or then have an effective fracture for production.

Q. All right, sir. Let's turn to page 8. Identify and describe this next topic.

A. I've tried to quantify the differences that -- between the two allowables and the resulting effect on cleanup.

As far as cleanup and ensuring that you're doing everything that you can to clean the fractures up and have all zones producing, you'd want those zones to be producing at capacity.

And I've made an example calculation with initial well capacity. I have an assumed decline rate, I have 30 and 60 percent per year. They are ranges that are based upon other Delaware producing fields that would be indicative more of a solution gas drive reservoir than a water drive reservoir.

If you had a well that had a capacity of 300 barrels a day, if that would normally decline at 30 percent per year but was restricted at the statewide allowable of 107 barrels of oil per day, it would be 1846 days before the well was producing at capacity under the statewide allowable, whereas you would be producing at capacity initially under the 300-barrel-a-day allowable.

And I have shown example calculations for varying rates which would represent wells not capable of the 300-barrel-a-day allowable, but capable of exceeding the 107-barrel-a-day allowable.

Q. So what's wrong with increasing the length of time for cleanup of the wellbore?

A. The fracture efficiency will be less, the fluids, the fines, anything disturbed as a result of the fracture treatment may be left for longer periods of time, or ultimately not removed from the formation, left as permanent damage.

Q. And what will that damage do in relation to ultimate recovery of hydrocarbons from the reservoir?

A. It would lower the ultimate recovery, especially for the tighter zones in the reservoir.

Q. Have you made engineering calculations and summarized for us some engineering procedures with regard to determining the effective fracture treatment for these sands?

A. As far as when they should be treated?

Q. Yes, sir.

A. Yes, I have. That's shown on page 9.

Q. All right, sir.

A. Page 9, I show a mathematical equation to determine the pressure required to initiate a vertical fracture and to extend a vertical fracture, and as I stated before, this is a function of reservoir pressure.

I have a -- calculated these pressures for an assumed initial condition of 2500 pounds per square inch reservoir pressure, and 1000, representing a more depleted zone.

The fracture pressure required to extend the fracture, at initial conditions, is 4053 pounds.

The fracture extension pressure for the depleted case is 3259 pounds.

So if you had two zones and you had initially treated only one zone successfully and came back to treat the other zone at a later date, the zone that was depleted would preferentially extend and would accept the fracture treatment preferentially, fluids, sand, and you would not be able to treat the zone that was still at initial pressure, or certainly not nearly as effectively as you would otherwise.

Q. Have you summarized your conclusions for the Examiner on page 10?

A. Yes, I have.

Q. Let's have you do that for us.

A. Okay. We feel at this time that we've got significant reserves in multiple sands within the Delaware. We require hydraulic fracture treatments to produce these sands.

We believe that if only one or two of these sands are initially treated, then we would not be able to treat the remaining sands at a later date because the first sands that produced would be depleted and would essentially take the additional frac treatments.

We do not see any barriers in the Delaware. The tighter sections we frac'd through, and so we believe it would be -- it is not possible to contain the fracture treatments at a later date.

And we feel that making the 300-barrel-a-day allowable permanent would allow effective depletion of all of the sands in our wells.

MR. KELLAHIN: That concludes my examination of Mr. Jones.

We move the introduction of his Exhibits 1 and 2.

EXAMINER STOGNER: Any objection?

MR. CARR: No objection.

EXAMINER STOGNER: Exhibits 1 and 2 will be admitted into evidence.

Mr. Carr, your witness.

MR. CARR: I have no questions of Mr. Jones.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Jones, another portion of this Application today involved a higher GOR. Do you have any opinion on that?

A. We have not seen any GOR increases to date. Our production is too premature for that. As far as the depletion of reservoirs, for the quality and type of assumed drive that we have here, I see no problem whatsoever with the 3000-to-1 GOR.

Q. But you haven't experienced a need for it in your area yet?

A. No, we have only two wells that have produced for almost four months, and another -- the Number 12 well has probably produced for less than a month.

So we're in the very early stages of our development in Section 34. We're just trying to get it right the first time through.

Q. Your map that is included in Exhibit Number 2 shows some other wells. Are those proposed, or are those deeper wells?

A. Those are staked locations. The Number 2 is a Delaware producer, the Number 3 is a Delaware producer, the Number 12 is a Delaware producer. We are currently completing the Number 7. The Number 1 well in the northwest of the northwest of that section is a Grayburg producer.

We are drilling the Number 14 and the Number 10 at this time in the southern part of the southeast section, southeast quarter.

EXAMINER STOGNER: I have no questions of this witness.

He may be excused.

MR. KELLAHIN: All right, sir. That concludes our presentation.

EXAMINER STOGNER: Anything further, Mr. Carr?

MR. CARR: I have nothing further, Mr. Stogner.

EXAMINER STOGNER: Mr. Kellahin, do you have anything further?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Mr. Carr and Mr. Kellahin, since your clients are both in favor of this, if you'll maybe collaborate --

MR. CARR: Yes, sir.

EXAMINER STOGNER: -- and provide me a rough draft order.

MR. KELLAHIN: Yes, sir.

MR. CARR: Yes, sir.

MR. KELLAHIN: Be happy to do that.

EXAMINER STOGNER: And I'll leave the time period up to your discretion.

MR. CARR: Thank you, Mr. Stogner.

EXAMINER STOGNER: And if there's nothing further in either Case 10,653 or 11,225, this matter will be taken under advisement.

And with that, hearing is adjourned.

(Thereupon, these proceedings were concluded at 11:28 a.m.)

* * *

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 March 19th, 1995.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case Nos. 11225/10653 heard by me on 16 March 1995.

Examiner
Oil Conservation Division