STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

APPLICATION OF THUNDERBOLT PETROLEUM TO INCREASE THE MAXIMUM SURFACE INJECTION PRESSURE ALLOWABLE WITHIN THE CALMON STATE WATERFLOOD PROJECT, EDDY COUNTY, NEW MEXICO

CASE NO. 13,249

ORIGINAL

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REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

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

June 10th, 2004

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, WILLIAM V. JONES, JR., Hearing Examiner, on Thursday, June 10th, 2004, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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Examiner Hearing
CASE NO. 13,249

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A P P E A R A N C E S

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* * *

ALSO PRESENT:

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* * *

WHEREUPON, the following proceedings were had at 8:22 a.m.:

EXAMINER JONES: Okay, let's call Case 13,249, which was continued from April 15th. Application of Thunderbolt Petroleum to increase the maximum surface injection pressure allowable within the Calmon State Waterflood Project, Eddy County, New Mexico.

Call for appearances.

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of the Applicant, and I have one witness to be sworn.

EXAMINER JONES: Any other appearances in this case? There being none, will the witness please stand to be sworn?

(Thereupon, the witness was sworn.)

MR. KELLAHIN: Mr. Examiner, Mr. Lee on behalf of his company operates this waterflood. It's a quarter-section waterflood with two injection wells. It's been previously approved by the Division, and a number of months ago he filed an administrative application with the Division seeking an increase in the surface pressure limitation for his two injection wells. That request, filed administratively, sought to increase his approval to a pressure of 1100 pounds per injection well.

After reviewing that matter, you asked that the case be placed on the docket so that Mr. Lee could come forward and present additional information and discuss with you his proposal for that increase, and we're here today to do that.

EXAMINER JONES: Okay.

ROBERT LEE,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. Robert Lee. I'm a petroleum engineer.

Q. And in what community do you reside?

A. Midland, Texas.

Q. Have you previously qualified before the Division as a petroleum engineer?

A. Yes, I have.

Q. And you've testified before the Division in other cases, including your own application that was approved for this waterflood project?

A. Yes, I have.

Q. And you were the individual responsible for filing with the Division the administrative application to increase the surface injection pressure on your two injection wells that are within this waterflood area?

A. Yes, I was.

Q. And pursuant to the notice of hearing, have you prepared additional exhibits and information for presentation to Examiner Jones, this morning?

A. Yes, I have.

MR. KELLAHIN: We tender Mr. Lee as an expert witness.

EXAMINER JONES: Mr. Lee is tendered as an expert witness.

Q. (By Mr. Kellahin) Mr. Lee, let's take a moment and unfold Exhibit Number 1. Let's take a moment, Mr. Lee, and look at the bottom right portion of Exhibit 1 --

A. Uh-huh.

Q. -- and have you identify what we're seeing by the outlined yellow area.

A. Yes, that's the 160 acres in the southwest quarter of Section 16 that comprises my Calmon waterflood.

Q. Describe for Mr. Jones how you have identified the location of the two approved injection wells.

A. They are the two westernmost wells that have triangles drawn around them. The Calmon Number 1 is the northernmost well, the Calmon Number 3 is to the south of that well. And they are on the cross-section as being the two wells on the right-hand side of the cross-section. The orange line kind of shows the line of section from A-A'.

And the other well that's on the cross-section is the Oxy Remuda Number 1. It was a deep well that was drilled to the Morrow.

Q. Can you use this display, Mr. Lee, and identify for us the number and the approximate location of the producing wells in the waterflood?

A. Yes. To the -- starting on the west side of the yellow block in what would be Unit Letter L is the Calmon Number 2. In Unit Letter M, covered up by the little "a", is the Calmon Number 5. In Unit Letter N is the Calmon Number 6. In Unit Letter K is the Calmon Number 4, and that's a TA'd well right now.

Q. Let's go to the A-A' cross-section portion of the display, and let's look at the Number 1 injection well in the middle.

A. Uh-huh.

Q. What portion of the log have you displayed for this well?

A. What I'm showing here is from the top of the Queen down to the TD of the well, which is just right at about 3000 feet, and the top of it starts at about 1950. And I'm doing that so I can show what the top of the pool is, the Queen-Grayburg-San Andres Pool, the Loco Hills.

Also identified on this --

Q. This production is associated with the Loco Hills Pool --

A. Yes.

Q. -- that's identified as the Loco Hills-Queen-Grayburg-San Andres Pool?

A. Yes, sir.

Q. Is the entire vertical extent of that pool shown on the log for the Number 1 injector?

A. No, it is not.

Q. Where would we find the top and the bottom of that pool?

A. That's why I put the OXY Remuda well on it, the deep well, to show the bottom of the San Andres. And I'm picking that at about 3975, which would be the top of the Glorieta. And none of the other wells that I operate went that deep. They just went down pretty much to the top of the San Andres.

Q. Show us on the log for the OXY well where we would find the top of the pool.

A. The top of the pool would be along the line that says Queen, and it is at a depth of about 2058.

Q. When we look, then, at the cross-section and look at where your two injection wells are perforated, describe for us the characterization of the reservoir portion of the pool that you're using for injection.

A. Okay, they're shown on the cross-section, highlighted in yellow, and what you can see are these fairly thin, somewhat tight sands spread out over several hundred feet of section there.

Q. Geologically, Mr. Lee, when we look at your waterflood area, can you give us a summary of the geologic sense of your flood area in comparison to the rest of the pool?

A. Yes, as I said, the zones that I'm injecting into, you can see the little porosity spikes here where you pick up these sands, and in between the sands it's pretty much anhydrites and dolomites, very, very tight formation, and you can see that on the porosity logs here that I've included. Both of these are compensated neutron logs, and you can just see that it's a very, very, very tight section there between my little sands there that I'm injecting into.

Even up to the top of the Queen, which is a sand, there it's still fairly tight; it's only got about 5-percent porosity there in the Queen, and we're typically thinking 8 to 10 percent is what we need to be productive.

Q. Mr. Lee, have you satisfied yourself as an expert engineer that you have adequate reservoir distance between your top and the bottom injection intervals and the top and the bottom of the pool?

A. Yes.

Q. Can you characterize for us the composition of the distance from the upper perforation and an injector to the top of the pool?

A. Yes, the top of the injector -- top of the injection zone in Well Number 1 is at about 2260, and the top of the Queen is at about 2030, so there I have about 230 feet from the top of my injection zone to the top of the Queen. And over on Well Number 3 my top injection zone is once again about 2260, and the top of the Queen is still about 2030, so once again I've got about 230 feet between my top perf to the top of the Queen.

Q. Within the half-mile area of review for these injectors, Mr. Lee, are there any problem wells --

A. No.

Q. -- in a half-mile radius?

A. No, there are not.

Q. So all the wells within that half-mile radius are adequately cased and cemented across the injection interval?

A. Yes, they are.

Q. Are you adequately isolated from any freshwater sands.

A. Yes, we are.

Q. Does the increased injection pressure that you're requesting, the 1100 pounds -- are you able to conclude that that's going to stay confined to the vertical limits of the pool?

A. Yes, based on some testing that we've done, it looks like it will be confined into this Queen-Grayburg-San Andres Pool.

Q. In addition to step-rate tests, have you run other tests on your injector wells to give you an engineering basis for an opinion as to the maximum extent of the pool that's being exposed to injection?

A. Yes, we ran some tracer surveys indicating where the injection of water may be going to within this interval.

Q. We'll look at those in a minute. Let's turn now to another cross-section where we can see the relationship of the injection wells to your producing wells. If you'll take a moment and unfold Exhibit Number 2, Mr. Lee, let's take Exhibit Number 2 and have you walk through an explanation of the relationship to how you're using the injection wells in relation to the zones of perforation in the producing wells.

A. Okay. The injection wells, Well Number 1 and Number 3 are identified by small triangles sitting above those logs. Well Number 1 is the far left-hand log, and the Well Number 3 is the fourth from the left. And the perforations are marked and highlighted in yellow.

And this cross-section is just pretty much across the productive interval here, and so I don't have the Queen included in this cross-section. But here you can see where my wells are perforated, demonstrating the continuity of pay between my injection wells and my producing wells.

There's one well, the TA'd well, which is Well Number 4. It was perforated down low in the Premier section, and the previous operator before I acquired the property had set a cast-iron bridge plug and TA'd the well, and we just got through running an MIT on that a couple months ago.

It does have some zones in it, as well as Number 6, in the Penrose that appear to be a little bit tight, about 9- to 8-percent porosity, that I do intend to go in and recomplete once we see some more response in our waterflood.

Q. Do you see any indication in the operation of the waterflood that you're conducting, that the injection water is moving out of the vertical limits of the pool?

A. No, there's nothing that would seem to indicate that.

Q. Let's turn, then, Mr. Lee, to Exhibit Number 3. For the record, would you identify that for us?

A. This was an order for a pressure increase that was granted for these two wells back in August of 2002. They -- increasing the pressure from what we had originally been given with the initial waterflood order, which was 453 pounds. And step-rate tests were ran, and the maximum pressure was granted for the Number 1 of 650 pounds and the Number 3 of 550 pounds, in August of 2002.

Q. Let's turn, then, to Exhibit 4 and have you identify what Exhibit 4 is.

A. This is a letter which I had sent to the OCD seeking increased injection pressure to 1100 pounds. I sent that in February of 2004, and I sent that along with some information seeking administrative approval of the increase in injection pressure there.

Q. This is your request to the Division that has resulted in this morning's hearing?

A. Yes, it is. Yes, it is.

Q. Let's turn to Exhibit 5. Identify for us what we're looking at when we see Exhibit 5.

A. Exhibit 5 is a step-rate test that was ran in February of 2004 on --

Q. On which well?

A. -- the Calmon State Number 1, and --

Q. What does this test results show you?

A. This test showed that the -- based on the graph, that the parting pressure of the formation is 805 pounds.

Q. Let's turn to the second page of that step-rate test, Mr. Lee --

A. Okay.

Q. -- and let's go through the plot. Show us the pressures and the rates and where you have breakover.

A. Right, okay. The rate is plotted along the bottom, the pressures are along the side. The dots are the recorded rate and pressure at different rates, they're recording the pressures that's documented on the first page, and you start getting an established slope.

And then after about 670 barrels a day of rate, the slope changes. And by drawing those two lines and looking at that point that they intersect, that's used to determine the parting point, the parting pressure of the reservoir. And like I said, that point appears to be 800 pounds.

Q. Do you have a similar step-rate test for the other injection well?

A. Yes, I do, Exhibit Number 6 is for the Calmon State Number 3.

Q. Let's look at the second page of Exhibit 6 and have you walk us through the plot.

A. Once again, water rate is plotted along the X axis, pressure is plotted along the Y axis. And same thing, we're getting several points to establish a slope, prior to that slope changing, at a rate of about 420 pounds, 420 barrels a day, and the parting pressure of the Number 3 well is 787 pounds. Both of them right around 800 pounds.

Q. Explain this for us, Mr. Lee. If we take this step-rate test for the Number 3 well, you're injecting at a certain rate, achieving a pressure at which there is a -- you called it a parting of the reservoir.

A. Right, where you're --

Q. When we're looking at the wellbore itself, what portion of the reservoir, then, is exhibiting parting?

A. Where the perforations are. And my perforations are, like I said, scattered over 300 or 400 feet. So there's really no way of knowing which set of perfs might be the perforations where you're seeing the frac'ing occur at. But it indicates that -- at this pressure, that you are parting some zone in the reservoir.

Q. Is there any way to take this information and reach a conclusion that you're parting the pool limits, that you're fracturing outside the vertical limits of the pool?

A. No, there's not. No, there's not. This does not tell you anything about the vertical frac-height growth or anything like that. This is just saying -- or even the horizontal -- how far out your fracture wing may be. All this is telling you is at what pressure and rate that reservoir starts to crack open.

Q. Have you conducted additional tests on these two injection wells so that you could measure the height of the fracture --

A. Yes.

Q. -- exposed at 1100 pounds?

A. Yes, we did.

Q. And how do you do that?

A. We ran injection surveys, tracer surveys, and we have those listed as Exhibits 7 and 8, and --

Q. Let's start with Exhibit 7, which is the Number 1 injector.

A. Yes, it is.

Q. Let's take a moment, unfold that. Is this a tracer test on your well, conducted by a service company?

A. Yes, it was, Cardinal Surveys ran this tracer survey for me.

Q. Are they recognized within the industry as a service company that's competent and -- to run these type of tests?

A. Yes, they are.

Q. Are their test results relied upon by you and other experts in the industry to reach conclusions about your injection wells?

A. Yes, they are.

Q. Give us a summary before you talk about the specific details. Tell us a summary of what we're about to see.

A. Okay, the way that they run a tracer survey and temperature survey is, they will run a temperature with the well being shut in, and then they will run a temperature survey with the well injecting, looking for anomalies within the temperature gradients, indicating where fluid flow may be, fluid flow behind pipe, things of that nature.

And then the tracer aspect of it is, they will inject a slug of radioactive material above the perforations, and as that water travels down across the perforations, water goes into the perforations and diminishes the amount of radioactive material. And they're logging through that, counting how much radioactivity is left in that wellbore, and based on that they can estimate how much water went out of zone.

They're also running a velocity survey where they're measuring the change in velocity up and down the well also. And the velocity survey can be a little bit skewed because of scale or buildup inside the casing at this point here, and --

Q. So when we look at this display, when we see the wellbore projection and look to the right side of the scale, we're seeing the temperature?

A. Yes.

Q. And that's displayed in the dashed line and the solid line?

A. Yes, the temperature survey that was ran when the well was injecting -- and on this well the injection pressure was 1000 pounds when they were running these surveys -- is the dashed line. The shut-in temperature is the solid dark line.

Q. What portion of this profile relates to the velocity information?

A. The first track immediately to the right of the middle of the log. If you look at the perfs at 2500, the velocity survey shows that 44.6 percent of the water enters into those perfs. And the radioactive portion of the log is on to the right of that, and it shows that there's 46 percent of the water going into that set of perforations.

Q. When we look at the left side of this profile, what tracks are we looking at there?

A. What you see there are the gamma-ray, which is the line to the far left on the log, and you'll also see a casing collar log on the -- sort of the right side of the left track.

Q. What, then, is the measured height of the indications on the tracer for the height of the frac using a pressure of 1100 pounds -- I guess it was a 1000-pound test --

A. Yeah.

Q. -- 1000-pound test, in this injection well Number 1?

A. The temperature survey -- When we were saying that Cardinal was an expert in their field, that's generally a pretty good statement. Here they dropped the ball a little bit because I had these perforations at 2265 down to about 2295, and they did not run the radioactive tracer across that set of perfs. In talking with the operator later, he just missed it.

But we can see on the temperature survey, the shut-in temperature shows a slight deviation across that set of perfs, and -- indicating that fluid does enter into those perfs.

Q. Does that lack of information, Mr. Lee, cause your conclusion about there being an adequate distance from the top of the interval affected by injection in the top of the pool?

A. No.

Q. That doesn't compromise your conclusion?

A. No, because even though they didn't have the tracer survey, the temperature survey indicates that there's no channeling. And I specifically ran these surveys looking for channeling or frac-height growth or something like that. And even though they missed that on their radioactive tracer survey, the temperature survey shows no channeling.

And then looking at the bottom portion, as far as how far down we go, the injection tracer shows that there's -- from my perforations at 2600, there's a little bit of movement down below that to maybe about 2618, about maybe eight feet below the perforated interval. But the temperature survey shows a little bit more of an anomaly down to 2634, before those curves come together and join up. And both of those indicate that movement down, they're still above my bottom set of perforations, which is about 2678 to -60. And in fact, this tracer survey here shows that there's no water going into my very bottom set of perforations.

Q. Let's look at the bottom of the pool. Your bottom perforations are going to put water in the -- sort of the middle and upper San Andres?

A. No, actually those perforations there, if you look back at our Exhibit 1, it's more in the middle bottom of the Grayburg interval --

Q. Oh, I see.

A. -- and still above the San Andres. There's --

Q. I misread this. The injection is in the Grayburg, there's nothing in the San Andres?

A. That's correct.

Q. In this immediate area, is there any Glorieta production?

A. No, there is not.

Q. So you see no potential risk to compromising further oil production below the base of your waterflood?

A. That's correct.

Q. And above the clean interval of your pool is the Seven Rivers. Is there any Seven Rivers production in this area?

A. No, there is not.

Q. Let's turn to the tracer survey for the Number 3 well. If you'll look at Exhibit 8 for us.

A. This is, once again, another tracer survey that was ran. The perfs are shown there in the middle track. The shut-in temperature, the injection temperature -- here the injection temperature and the tracers were ran, and we had a pressure of 1120 pounds on the well at that point in time.

The tracers, radioactive tracer, indicates loss into all the perfs except for the very bottom set of perforations at 2600. The temperature survey on this one was pretty erratic looking, and even the Cardinal people did not have a good explanation as to why this temperature survey looks like it does.

At the time that we were running this back in November of '03, it had been pretty cold in the days before that, and so some of this cooling that we see even on our shut-in temperature may be due to some -- you know, just cool water that had been in the pipe, kind of giving us an erroneous reading.

Q. Are you still able to use this log information to tell you that you have adequate separation between your injection intervals and the top and the bottom of the pool?

A. Yes, we do. We don't -- As I say, we don't see any tracer radioactive movement behind the pipe, and they do see a bit of an anomaly in the shut-in temperature at a depth of about 2140, and so they're making a call there of a possible channel up to about 2140. But that is still about 140 feet or so, I believe, below the top of the Queen.

Q. Have you satisfied yourself, Mr. Lee, that you have adequate measured information for the two injection wells to recommend to the Examiner that he improve your increased injection pressure?

A. I believe so. Like I say, we're not seeing any of the radioactive material moving behind pipe here. The only thing that we see is a possible channel. Once again, it's still well below the top of the Queen, and due to the erratic nature of the temperature survey here, you know, even the pick at 2140 might be questionable.

Q. Do you have available to you any information from which you conclude that you should not do this?

A. No, I do not.

Q. Let's see what the profile has been for your waterflood project. If you'll turn to the plot that you've prepared and submitted as Exhibit 9, take a moment and identify for us what we're seeing.

A. This is a plot of water injection, oil production and pressure from the start of the flood in October of 2000 through May of 2004. And what we're showing here is the water injection rate, shown in blue; the oil production, shown in green; and our pressures, plotted in pink. And what we're --

Q. Are you seeing a positive response in improved oil recoveries in relationship to water injection?

A. Yes, yes, we are. When we first started the flood back in 2000, we were at about 100 barrels a month, and oil and p.s.i. -- our pressure is plotted, the numbers for those are on the right-hand side of the plot, and the rate is shown on the left-hand side.

And you see the blue line going up, we start putting water in the ground, very little pressure initially. We start catching some pressure in about June of '01, and --

Q. Let me ask you in December of '01, we see a dramatic drop in the water rate.

A. Uh-huh.

Q. Is that a function of a reservoir problem or a problem with any of your wells?

A. No, it was a problem with the water supply. Prior to that, in October of '01, the blue line goes up to about 15,000 barrels a month, as we were able to tie into some other water sources. And those sources went away in February of '02, and our injection dropped. Shortly after we started putting additional water in the ground, we did start seeing an increase in our oil production, going up to about 160 barrels of oil a month.

And the blue line is fairly erratic from about December of '01 to February of '03. Once again, just problems with water sources and getting make-up water for our flood. And during that time our oil production kind of languished and just kind of held in there at the 160-170-barrels-a-month range.

In February of '03 we were able to once again secure some additional water-injection sources, and our blue line goes back up to where we're putting way a rate of 10,000 to 11,000 barrels a month. And at that time, because we're putting more water in the ground, you can see the pink line go up to where our average injection pressure is right around 1000 pounds.

About three months after we secured this additional water in October of '03, we started to see an increase in our oil production and got up to almost 450 barrels a month and -- tailing off a little bit. Then we had our order to shut down the injection in December of '03, and when we shut the water down you can see the blue line dropping off. You can see our oil starting to drop off at that time also, and pressures dropped down.

And what we did to arrest that was, we started putting in a little more water to try to stabilize our oil rate where it wouldn't continue falling, and also to do some testing here as to -- if I start putting more water in the ground, will I start seeing this oil rate come back? I was getting pretty concerned that if I, you know, just shut injection down, do I start losing my oil front? And so we started putting more water in the ground, and the oil has at least stabilized at a --

Q. Have you reached a reservoir fill-up on your --

A. No, we have not.

Q. -- waterflood project?

A. No, we have not.

Q. Have you prepared some voidage calculations for

Examiner Jones?

A. Yes.

Q. Let's turn to Exhibit 10 and have you take us through this display.

A. Okay. This is a calculation of the reservoir voidage, and I'm estimating the initial pressure of the reservoir to be about 1100 pounds, just based on a standard gradient to the mid-perf. And original gas in solution was about 270 standard cubic feet per barrel. My initial producing GOR was about 1000 standard cubic feet per barrel, and that increased over time as the pressure dropped.

The B_{gi} that I calculated for that free gas in the reservoir was 1.47 reservoir barrels per MCF, and the B_{oi} is 1.14 reservoir barrels per standard barrel.

At 10 of 2000, when we began injecting, we'd cum'd about 106,000 barrels, 50,000 barrels of water, and the cumulative gas was 213,000 MCF. And I calculated what an average producing GOR would have been. That would be 2000 standard cubic feet per stock tank barrel.

On my reservoir voidage calculation, I calculated the voidage created by the oil that I had produced, I calculated the voidage created by the free gas that has been produced, and the water voidage, which would just be the water production. And my oil voidage was 106,000 times

1.14 B_{oi}, gave me 121,000 reservoir barrels.

The gas voidage is what has really created a lot of problem here. It's a pretty big number. I took my average producing GOR, which is 2000 to 1, minus my 270 R_s number, the gas-in-solution number, times my oil that's been produced, times the B_{gi}, the reservoir barrels per MCF that was associated with the free gas, and that gives me 319,000 barrels.

So my total voidage at the time injection began was almost 490,000 barrels, and to date I've only put in 233,000 barrels, which is still a little less than 50 percent of fill-up.

And that kind of fits with what I'm seeing over here on my production. You know, typically you'd think that you should start kind of really seeing some response when you get there to, you know, that 40 -- you know, maybe 30 to 50 percent of fill-up, typically you should start seeing a little bit of something, but -- and we've done that. So it looks like everything's kind of working like it ought to, it's just taking a long time to get it filled up.

Q. Under the Division order that you received, there was a base of pressure gradient of .2 p.s.i. per foot of depth, and that was subject to modification if you presented the Division with appropriate information. Have you calculated for us what the fracture gradient is, if we use 1100 pounds of pressure?

A. Yes, I did, and I'll recalculate it now to make sure it's a fresh number, because I forgot to write it down yesterday when we were doing that.

If my top perforation -- and I'm -- in calculating the surface pressure gradient, I'm picking -- using my top perf versus something that would kind of be in the -- mid-perf, because that top perf is what's going to see that pressure, kind of, first --

Q. You're going to calculate us a surface pressure number?

A. Yes, I am. With 1100 pounds at the surface, with my top perf at about 2260, that's going to be a .486, say .49, surface gradient at 1100 pounds.

And if I take the step-rate test numbers, say at about 800 pounds, divided by the 2260, I get a gradient -- surface gradient of .35. So what we're asking is about another .13 p.s.i. per foot on that surface gradient so we're able to get some -- get the water in the ground.

Q. If the Division approves this for you, Mr. Lee, will you recover oil that you would not otherwise produce? If you take the pressure up to 1100 pounds, is that going to give you an improved oil recovery? You get a better rate, do you not?

A. It's going to increase our rate, help us get the oil out of the ground --

Q. Sooner?

A. -- much quicker. And that was one of the conclusions I had drawn based on this voidage calculation, is that if I have to stay around the 700- to 800-p.s.i. surface pressure I'm only going to be able to get away -- based on some of the testing we've done here, is 4000 to 5000 barrels of water a month, and that takes me almost four years -- a little over four years to reach fill-up.

If I can go up to the 11,000 barrels a month, 10,000 to 11,000 barrels a month, which is where we were when we were seeing some pretty good increase at the pressures of 1000 to 1100 p.s.i., I can reach that fill-up in two years then.

So yes, if I can have a higher pressure increase, I can get more water in the ground and I'll get greater response quicker.

Q. Anything else, Mr. Lee?

A. I've kind of -- You know, one of the things I've looked at here is kind of why, you know, if my reservoir is parting at 800 pounds, why am I able to get better response and increase production by being up around 1000 to 1100 pounds?

And I believe that the reason that it seems to be working that way is because, with the system that I have we're getting a lot of iron-sulfide problems out here. We've got filters at the injection wellheads. But still, it's just -- that iron sulfide, like talcum powder, just going through everything. And it's plugging up my perforations, and I'm needing to get out past that a little bit. That seems to be kind of the -- what really kind of creates this issue of needing the additional pressure. I wish I didn't, but...

MR. KELLAHIN: Mr. Examiner, that concludes our presentation. We move the introduction of Mr. Lee's Exhibits 1 through 10.

EXAMINER JONES: Exhibits 1 through 10 will be admitted to evidence.

I can see Mr. Carr cringing back there about me asking all these questions, but I'll go ahead and start.

MR. KELLAHIN: He's being paid to suffer, Mr. Examiner.

EXAMINER JONES: He is.

THE WITNESS: He's not paying me, is he, Tom?

MR. KELLAHIN: No, he's not. Neither am I.

EXAMINATION

BY EXAMINER JONES:

Q. Okay, let's talk about the waters first. Starting with the fresh water, what depth is the fresh water out here?

A. Surface casing is set to 400 feet in this area. In initial waterflood study I looked for any freshwater wells within the area, and there were none shown by the State Engineer's Office. But casing -- surface casing is at 400 feet.

Q. And there's pretty much -- What about the Yates and the --

A. The Yates is at about 1100 feet out here, and it is productive. I've popped the Yates in the Number 2 well, and we're producing it. It's real low BTU gas, it's like 600-BTU gas. The well makes probably about 40 MCF a day. So the Yates was productive there, but then I tried it in the Number 6 and the Yates was not productive.

Q. So the Yates has a little nitrogen in it?

A. Uh-huh, a lot of nitrogen in it, yeah.

Q. And what about the salt zone out here? What depth is it?

A. I'm not sure, I don't know. I hadn't really looked at that.

Q. It's a long ways up the hole.

A. Yeah. If it's -- Yeah.

Q. And on your AOR wells, how many wells are within a half mile, or -- just an estimate?

A. Probably about 15.

Q. Okay.

A. I had that on a C-108, but I don't have it right here.

Q. That's good enough.

A. Okay.

Q. The water that you're producing from the Queen, what TDS is that water, what quality is that water?

A. The water that we're producing -- we've been having Baker Chemicals keep an eye on that for us -- it's not too bad. It's got some solids in it, but it's really not the problem.

The problem is the water that I'm bringing in, and I don't have a good water source here and I'm having to truck in water. So you're ending up with water that's coming out of an open-top tank into a water truck and then coming over here, picking up a lot of oxygen and iron. And Baker is treating it, mainly trying to scavenge the oxygen and slick up and dissolve any iron sulfide or slick up whatever's there to just make it move out through the reservoir. But that's the main problem.

Q. Okay, thanks. And what's your injection-withdrawal ratio out here? If you can inject at 1100 pounds or so, what would be your injection-withdrawal ratio? Or just -- roughly.

A. Yeah, we're putting -- make about 20 barrels of water and 10 barrels of oil, so we've got about 30. And you know, the gas is -- probably my reservoir GOR is dropping down as I've reached some fill-up here -- but it would be 10 to 1.

Q. So where is that water going?

A. Well, at this point in time it's going out into the reservoir, still filling up the reservoir voidage.

Q. Okay --

A. Yeah, a lot of --

Q. -- going laterally somewhere else that -- outside, at least, to bother anybody else?

A. I have not seen or heard of any indication from any of the surrounding operators.

Q. Okay. Do you have an idea of the directional permeability out here?

A. No, I do not. There was no cores ran, cut, whenever the wells were drilled, but -- from a physical standpoint like that.

But I do believe that it's probably a northeast-southwest permeability trend, because the Number 5 well appears to be seeing more response than the Number 6 or the Number 2. I always figured my Number 2 would be the first to respond because it's kind of in between my two injection wells. But it's Number 5 that's seeing the response, so I'm going to say it's a northeast-southwest trend.

Q. Okay. Do you have any initial shut-in pressures from acid breakdowns or anything on --

A. No, and the files that I received after -- when I acquired the property were pretty thin. I was looking for, like I say, the breakdown pressures or the fracture-treating reports, and there was none of that in the well files whenever I bought the property.

Q. Okay, your casing -- how old is your oldest casing out here?

A. These wells were drilled in, I think, 1982, 1984 --

Q. Okay.

A. -- so they're fairly new.

Q. And how long do these casings last out here in the Queen? What do you think? Bad corrosion problems?

A. There doesn't seem to be, except where -- maybe you have some of these waterfloods over here at the Ballard Unit. I know that they had some casing problems. There were some other wells that I was looking at trying to acquire up to the north that were drilled in the 1960s, and they didn't seem to have any casing problems. These were cemented to surface, which should help us on the longevity of them.

Q. Yeah, okay. The current reservoir pressure, what do you think, out here?

A. The -- I'm guessing at about 300 or 400 pounds.

Q. So what's your bubble point then?

A. Well, I think that I had free gas in the reservoir at 1100 pounds, so -- it's kind of the way you look at the terms, but that was really the bubble point for that fluid at that point in time, because once I diminish any pressure there's going to be additional free gas break out of solution of that oil.

Q. Yeah.

A. You know, and actually it was below the bubble point, if you say bubble point is a point at which there is no free gas in the reservoir, and I haven't calculated that.

Q. Okay. So you've got clays in this. I notice your step-rate tests over time have risen, the frac pressure has risen?

A. Right, and I think that's an indication of reservoir pressure increasing over the last couple years, is what I attribute that to.

Q. And the slope is kind of -- it's not quite such a good break as it used to be?

A. Right, uh-huh.

Q. How about your surface controllers out here? How would you limit to make sure that you keep your wells at whatever the pressure allowable is?

A. We have a shutoff at the injection pump at the facility, so a Murphy switch there.

Q. Murphy switch --

A. Yeah.

Q. -- just shuts everything down?

A. Shuts it all down.

Q. Okay, and you keep it at the current allowable pressure and...

Now, what kind of pumps do you have out here?

A. We have one little Gas-O triplex pump.

Q. Gas --

A. Yeah, DB pump, plunger pump.

Q. And looks like part of your problem out here is your water, consistency of your water supply coming in.

A. Yes, and on that -- I think it was Exhibit 9, you can see that since February it has gotten better, February of '03.

Originally I had a pipeline over to an offset unit that I was going to get my water from, and kind of in the middle of 2000, whenever I was getting ready to put this in, they shut in all their high water producers. So I lost my water source.

So I've had to be trucking in water, and that's created a problem because sometimes those water haulers are -- you know, they'll bring in something not very good that's not where you told them to bring it from, when it's late at night.

Q. Yeah. Okay, I know there's been some analogous Queen floods that pressures have been allowed to go a little higher than -- or right at frac pressure or a little higher.

Do you have any close by that you know about?

A. I had looked at the Ballard Unit and over at Yates' West Loco Hills Unit, and it looks like some of their injection pressures are in the 1100- to 1500-pound range. But as far as what their allowable was, I don't know.

We had looked at the -- Of course it's kind of far away, but Wiser had received some increased injection pressures over frac pressures, but I mean they're north and east of Loco Hills, and I'm south and west.

Q. Okay.

A. I don't know of anything nearby, real nearby. Then there was a Peach Exploration unit over at the West High Lonesome. It was a Penrose sand unit.

Q. How over is that, about how...

A. Oh, I think it's like 12 -- 10 or 12 miles, probably.

Q. Now, the Penrose is a member of the --

A. Queen --

Q. -- Queen.

A. -- section, yes.

Q. So the top of this Queen that you've got perforated here, is that the Penrose?

A. Yes. Yes, that's the Penrose.

Q. Okay, and your Queen you're perforating is the highest porosity, but it's also pretty dirty stuff, it looks like?

A. Uh-huh.

Q. What kind of clays are in that?

A. I don't know. I don't have samples. It's looking pretty dirty. And typically what we think is that these are radioactive sands that create that hot gamma-ray look, rather than clays mixed in with the sands.

Q. Okay. With the prices of products pretty good out here now, what kind of spacing do you have on your -- on this flood here, per well, per producer? You've got 160 acres here, right?

A. Yes, uh-huh.

Q. And how many producers do you have?

A. I've got three producers.

Q. Okay.

A. Three producers.

Q. Okay. And instead of going with the higher pressure, have you thought of converting some more wells to injection and getting water in the ground faster that way?

A. If I had it all to do over again, I would have probably -- If you look at the map, it was almost set up to be a fivespot pattern the way it was originally drilled by the original operator. I have one well in the center, surrounded by four wells, and then the Number 1 kind of on the outside of that.

At this point in time I would have been better off if I would have converted all four of those wells. Theoretically an inverted fivespot will recover the same amount of oil as a fivespot pattern.

I was trying to minimize the amount of production loss whenever I converted the wells and minimize the amount of conversion costs by converting two wells instead of four, and so my up-front decisions have kind of come back to haunt me a little bit here. I'm afraid if I was to convert any of these other wells, I may not have a point to capture them -- capture any oil that I may move, is the problem.

EXAMINER JONES: Okay, I think we've hammered this long enough, and I appreciate you coming today.

THE WITNESS: Thank you.

EXAMINER JONES: I have no further questions.

MR. KELLAHIN: That concludes our presentation, Mr. Examiner.

EXAMINER JONES: With that, let's take Case 13,249 under advisement.

(Thereupon, these proceedings were concluded at 9:20 a.m.)

* * *

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

______________________, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL June 11th, 2004.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2006