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 NO. 13,893

APPLICATION OF YATES PETROLEUM CORPORATION FOR APPROVAL OF A PILOT PROJECT IN THE NORTH DAGGER DRAW-UPPER PENNSYLVANIAN UNIT FOR PURPOSES OF ESTABLISHING PROPER WATERFLOOD INJECTION PATTERNS AND FOR A TEMPORARY EXEMPTION FROM THE PROVISIONS OF DIVISION RULE 203 CONCERNING APPROVED TEMPORARY ABANDONMENT OF WELLS, EDDY COUNTY, NEW MEXICO)

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Jr., Hearing Examiner

March 29th, 2007

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner, on Thursday, March 29th, 2007, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

March 29th, 2007
Examiner Hearing
CASE NO. 13,893

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A P P E A R A N C E S

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By: WILLIAM F. CARR

* * *

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

EXAMINER CATANACH: At this time I'll call Case 13,893, the Application of Yates Petroleum Corporation for approval of a pilot project in the North Dagger Draw-Upper Pennsylvanian Unit for purposes of establishing proper waterflood injection patterns and for a temporary exemption from the provisions of Division Rule 203 concerning approved temporary abandonment of wells, Eddy County, New Mexico.

Call for appearances.

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe office of Holland and Hart, L.L.P. We represent Yates Petroleum Corporation in this matter, and I have one witness.

EXAMINER CATANACH: Okay, will the witness please stand to be sworn in?

(Thereupon, the witness was sworn.)

<u>DAVID F. BONEAU</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. David Francis Boneau.

Q. Dr. Boneau, where do you reside?

A. Artesia, New Mexico.

Q. By whom are you employed?

A. Yates Petroleum Corporation, as engineering manager.

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

A. Yes, sir.

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

A. Yes, sir, they were.

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

A. Yes, sir.

Q. Are you familiar with the current status of the North Dagger Draw-Upper Pennsylvanian Unit?

A. I'm familiar with that.

Q. Have you made an engineering study of that unit and the area that is involved in this Application?

A. Yes, I've done that.

Q. Are you prepared to review the results of that work with Mr. Catanach?

A. That's why we're here, sir; I'm definitely prepared to do that.

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

EXAMINER CATANACH: They are.

MR. CARR: Mr. Examiner, today in this case, as you know, we're seeking an exception to the provisions of Rule 203. I think the way to explain what Yates seeking and why would best -- we'd best serve that purpose if Dr. Boneau would now refer to Exhibit Number 1 and, in doing that, explain what we're seeking and also provide some historical background that would put this Application in some context.

Q. (By Mr. Carr) Dr. Boneau, would you refer to Exhibit 1 please?

A. Exhibit --

MR. BROOKS: Excuse me, do you have another set of the exhibits?

THE WITNESS: Oh, you bet.

EXAMINER CATANACH: Right there.

MR. BROOKS: Oh, this is the -- Okay, sorry.

MR. CARR: In this case, we do not want for exhibits. I have several more here.

MR. BROOKS: I figured that was the case. I'm sorry, go ahead.

THE WITNESS: Exhibit 1 is a one-page list of 11 items that, if we can take the time to go through them, tells what we're up to here, I think.

So we're talking about North Dagger Draw-Upper Penn Unit, Eddy County, New Mexico. We've heard about this a little. Hopefully you recall it's a vuggy dolomite reservoir about 7500 feet deep, really great production five to ten years ago. We're here to tell you our story, and we need to be able to shut in wells while we continue testing, kind of figure out North Dagger Draw. Okay.

So the unit, which involves 101 wells, was effective February 1st, 2005. And just as a point of information, those wells on primary production before the unit was formed made 24.7 million barrels of oil -- so 25 million barrels of oil from 100 wells, about 250,000 barrels per well -- along with 63 BCF and a whole lot of water. You probably recall that these wells make water pretty much throughout their life. So we've got -- out of this area we've gotten 25 million barrels.

We think there are 50 million more barrels down there. They're going to be kind of hard to get, but they're there, it is an attractive target.

The unit was formed in order to waterflood and try to recover some of this oil. At the time the unit was formed, we had an engineering study done by a consultant in Dallas, under item number 4 here, that proposed an unusual approach, and it was -- I call it an irregular waterflood pattern. If you don't recall, you'll see it in a minute. And since everything about Dagger Draw is different, we went along with this different approach to the waterflood, with this strange-looking injection pattern.

And we began injecting into five wells, September 15th, 2005, and so we've injected for roughly a year and a half. And you'll see there's really been no oil response, no increase in oil production. As number 6 says, we've noticed some water movement, mostly in the east-to-west direction, east-west direction.

And our conclusion is that this irregular pattern, our first try out there, has failed. We've given up on what the consultant said. And so we're at a decision place as to what to do next.

And in my opinion -- the options are listed there, number 8, basically use a more normal injection pattern, which would be either a fivespot or a line drive, or the other option is quit, which means plug all the wells or try to recomplete them in some other zone, or some such thing. And we -- with 50 million barrels there in place, we really don't want to quit, but the options are rather expensive, and the odds of it working maybe are not that high. Anyway, we've got this problem.

What we're proposing, I tried to list in number 9, probably would take on the order of three years to do.

And as 9.a says, we'd like to do two kinds of well testing.

The first is some rather fancy measurements that estimate the oil saturation accessible to an individual well, around the well. And we would do that at two wells, at two places in the waterflood -- in the waterflood unit. The oil is there, but with the rock being vuggy it's not clear how much of the oil is really connected to the wellbores. And if that's very low we've got a really -- probably hopeless case. If that's reasonably high, we probably still have a chance. And there is a way to measure it, although you'll see it's relatively complicated and expensive. Anyway, we'd like to do two of those kind of tests to get actual numbers as to what kind of oil is available to the wells that we have.

And then we would like to do a couple interference tests where you measure east-west permeability and north-south permeability, and that would tell us what kind of a line drive has a better chance.

So anyway, we're talking about doing a little -- well, a little -- $200,000 worth of testing, which by the time it all gets analyzed probably takes six months. And then based on that testing, we would inject -- we would select a pattern, either the fivespot or the line drive, and try one of those. And that's going to take at least 15 months. If that doesn't work we might quit, or we probably would try the other pattern, and the other pattern would take another 15 months.

So at least for talking purposes, I'm talking about six months of testing, try plan number two, 15 or so months, maybe try plan number three for another 15 months, which would add up to approximately three years.

And so as number 10 says, we're requesting permission to leave the wells that are outside of the test area. These test areas would be -- would involve five, ten, twenty wells, not a hundred wells, and there's a whole lot of other wells sitting out there that are a problem to us with the must-produced rules.

And so we're asking that we can leave those wells outside of the test areas, what I call shut-in, during this testing period so that we can avoid having to keep them alive at a cost which approximates $300,000 a month, which over this -- is $10 million to keep -- I'm estimating it would cost us $10 million to keep the outside wells alive while we do this testing. And we can't afford that, nobody can afford that. I mean, I don't think -- Well, I don't know if Exxon could afford that, but we can't afford that.

So that's the dilemma, if I've made any sense there, that's the dilemma. And of the course at the end of the test period we hope that we -- relatively successful and could expand the waterflood and waterflood a decent portion of this unit, and if all these experiment things fail, you know, scout's honor, we'll plug the wells and do all we're supposed to and take care of things.

A really big reason that there's not much risk, I think, to the Commission and to us in approving this is that this is a relatively new field. Most all these wells were drilled in the 1990-to-1995 time frame, so they're 10, 15 years old, lots of them have 7-inch casing. Anyway, they're new wells, good cement programs, they're in good shape. Sitting there a few years is not going to hurt anything. It's not -- We're not talking about a 1920s field where everything is falling apart, we're talking about some relatively new wells that are in good enough shape to sit there while we do this testing.

That's kind of an outline of what we're up to here.

MR. CARR: And then, Mr. Examiner, I might add that we decided that we should bring this matter to hearing instead of trying to do any sort of an administrative pass at the OCD, keeping you in the loop, partially because there are approximately 340 interest owners in the unit, and in 2005 we had meetings about statutory unitization, explained the entire project to them, based on the study of the consultant, and we thought that the one way to be certain that everyone knew what we were doing would be to, as you'll see, provide working interest reports and then bring it here to hearing if anyone was concerned about it.

Q. (By Mr. Carr) Dr. Boneau, could you refer to what has been marked as Yates Exhibit Number 2 and identify that for Mr. Catanach?

A. Yes, and I think one more opening statement that probably we ought to make is that we're hoping for some kind of temporary approval with some -- I don't know, come back after a year and tell you where we are, or something. We doubt that we'll get a blanket three- or four-year you-don't-have-to-do-anything approval. So anyway, we're expecting maybe we talk about some kind of review process partway through this exercise.

Okay, Exhibit Number 2, it's the great big fat thing. It's the engineering report by -- it's called the Scotia Group, which are -- they're consultants in Dallas. It's the report that suggested the irregular pattern. My intention is not to look at anything -- well, it's not to go through the report page by page.

Exhibit 3 is a picture of what they've proposed, and I'm hoping we can just go look at Exhibit 3 and talk about what they've proposed.

Q. Let's do that. Would you go to Exhibit 3, please. Identify it first and then review it.

A. So Exhibit 3 is a map of a portion of Township 19

South, 25 East, in Eddy County, New Mexico. The green outline is the outline of the North Dagger Draw-Upper Penn Unit. It's approximately three sections by three sections with a little bite taken out of the northwest corner.

The blue triangles on the map are the wells that the consultant report suggests be injection wells. And you can see they're just sort of all over the place. The idea at the time -- the consultant's idea, which seemed like it had some merit at the time -- was that the reservoir is vuggy, it has water in it, it has some high-permeability streaks, et cetera.

The consultant's idea was to inject in the lower-permeability, tighter parts of the rock, where it was more likely that the oil was trapped, and try to force the oil out of those areas into adjacent higher-permeability places where then it could have a highway to some producing well. Maybe my words aren't too great, but that was kind of the idea.

These are -- the wells selected as injection wells were among the poorer producers. And I said the wells averaged 250,000 barrels over their primary lifetime, and so these wells were, you know, 150,000-barrel-a-day -- not barrel-a-day, 150,000-cum wells, as compared to 300,000 or 400,000, some of the others. Anyway, they were the poorer producers. They weren't poor producers, but they were the poorer, and the poorer producers was kind of inferred to be the tighter rock. That was the idea, that -- anyway, there was an idea.

We -- There's a red outline around that's listed as Phase 1A, and that was the starting point towards this, and that's -- what's shown there in Phase 1A with the solid blue triangles as injection wells is what we have done for the past year and a half or so. So we have injected into those five wells at rates between 2000 and 2500 barrels of water per day into each well, and we have summed -- we have recorded the production for inside that red outline as the pilot project, or as the initial project, the Phase 1A project. So that's what we've done, and that's what they suggested.

Q. Would you now review the waterflood operations conducted by Yates in the Phase 1 area, and in doing that would you refer to Yates Exhibit Number 4?

A. Exhibit 4 has a lot of -- again, has a lot of stuff on it. But it shows a summary of what happened. So there are four different colors -- well, actually five different colors in the plot there.

There's a yellow line that goes from the lower left corner up to the upper-right corner, and it's a measure of the cumulative water injected with the scale along the right-hand side. So during this period, roughly a year and a half, we've injected about 4.8 or 4.9 million barrels of water. That's what the yellow line is.

Then there are four wiggly lines representing oil, gas, water and water injected.

So the purple one at the top is the amount of water injected, with the scale on the left-hand side, and it's fairly constant, slightly above 10,000 barrels of water per day injected. Actually, it's about 12,000 barrels of water per day injected, roughly 2000 to 2500 barrels a day per injector. And you can see that -- we've held that pretty constant over the period of the flood after an initial startup when we injected at lower rates.

The light blue line is water produced out of those wells in Phase 1A, and it dribbled along about the 2000 level and in the last six months or so has gone up somewhat.

The red line is the gas produced from the producing wells in the Phase 1A area, and it started something about 600 and over time has drifted down to maybe 400. So the gas produced has actually gone down, which is an encouraging sign in a waterflood. You're trying to raise the pressure and force the gas back into the oil, and the fact that the gas has gone down is probably the only encouraging thing about what we've done.

The green line at the bottom, then, is the oil production out of the wells in this Phase 1 area, and it begins about 30 or 40 barrels a day and drifts along about 30 or 40 barrels a day and kind of tails off at the end. But there's nowhere that it really increased, and it needed to increase to 200 or 250 or something, to act like it was successful, and it did not do that at all. It did nothing.

Q. On the right of the exhibit are some additional numbers, current rate and things like that. Would you review those for Mr. Catanach?

A. Yeah, and I just had some white paper over there and wanted to stick some numbers in that would sort of help him maybe understand if I tell him what they are.

So before unitization we produced 24-point-something, about 25 million barrels of oil. Since the unit was formed a couple years ago, the total production from the unit has been 127,000 barrels of oil -- that's one of the numbers at the top there -- 1 BCF of gas and about 5 million barrels of water. So since unitization we have put in about 5 million barrels of water and we have taken out about 5 million barrels of water.

The next little group of numbers below there are current rates for the whole unit, not just the Phase 1A place, the whole unit, in January. And essentially we greatly reduced, almost stopped injection at the first of the year. We gave up on this first try at the first of the year. Anyway, these are the rates in January, and they're basically after we gave up.

So the rates for the unit -- the unit is now making 44 barrels of oil a day, 934 MCF a day and 2000 barrels of water a day, just more numbers to help you or confuse you.

Q. Dr. Boneau, let's go to Exhibit Number 5. Would you explain what this shows?

A. Okay, in Exhibit Number 5, again lots of numbers, but on -- and it's not -- whatever, you don't need to absorb it all, I don't think, but this exhibit is an attempt to show you the status of everything right before we gave up on try number one.

So I would call your attention to the five triangles in a north-south direction in the Phase 1 area, and there's -- next to each well there's a set of numbers, oil, gas and water. And for the injection wells there's a negative blue number, which is -- the negative indicates that it's injection. So just some more numbers.

But Well Number 53, the northernmost injection well, averaged 1899 barrels of water a day injected in December. And the next well below it, Number 60, 2224 barrels of water per day injected. And on down, 1700, 2000, 2300 barrels of water a day injected.

So in December we are injecting seriously into those wells, still trying to push things. And if you look at the surrounding wells to the east and west of that line of injectors you see low numbers for oil, like -- Well, 35 is 2 barrels of oil, 17 gas, 57 water. Underneath it, zero oil for 54, 19 gas, 219 water. Anyway, a whole bunch of little numbers. Nothing's going on, we're not moving much oil. And that's really the only point of the picture.

Q. Okay, what about Exhibit Number 6? What does this show us?

A. Exhibit Number 6 is the same kind -- exactly same kind of picture. It's for January, and it's basically after we gave up on try number one. And so it's more like the way the unit is sitting now. And I -- Well, it's got all the same numbers, every well next to it has an oil, gas and water number, et cetera. But I would just, you know, call your attention to the five triangles in the north-south direction, their water-injection numbers, minus 295, 295 barrels a day, 372 barrels a day, 272 barrels a day, 314, 402. Not zero, but reduced.

And so we're injecting some in there just to say we're injecting and maybe give us some time to get on to the next plan, but we've stopped serious injecting, and the producers have the same kind of low numbers that they had. The water production is reduced, since the -- in some of the nearby wells, since the water injection is reduced.

But the point of this Number 6 is just to lay out all these numbers for more or less this transition time, this intervening time. We've quit try one, we want to do try two, we've got to get all our ducks in a row, or whatever analogy you use, to go on and try something else.

Q. What kind of operating expenses has Yates incurred while working on this project?

A. In 2006, we averaged income of about $400,000 a month and expenses of about $800,000 a month. So in 2006, operating the Phase 1, we were losing about $400,000 a month, and that includes the cost of injecting, et cetera. It also includes some cost of trying to keep wells alive that -- you know, under the current rules that were shut in or that had been TA'd, we had some wells that had been TA'd, and their period of time came up and the BLM and the OCD would not remove the TAs, and we had to go out and spend money to pump those or reactivate them, et cetera.

Anyway, in 2006 we were losing $400,000 a month doing this Phase 1 -- operating the unit during Phase 1.

Q. All right, let's go to Yates Exhibit Number 7. Would you identify this for Mr. Catanach and explain what this shows?

A. Okay, Exhibits -- well, 6, 7 and 8 also are all aimed at showing, you know, as clearly as -- or at least my attempts at showing clearly the status of the wells now, when we stopped our first try and are talking about going on to try some other injection pattern.

So Exhibit 7 is simply a list of the 101 wells in the unit with their API numbers and locations, et cetera, and the three right-hand columns are the amount of oil, gas and water that each well produced in January.

And I guess I maybe could have taken a yellow marker or something, but anyway you go through the and there's quite a number that are zero, zero, zero, that were shut in. There's some that are zero oil and a tiny of gas and a little or no water, wells that we're not pumping. I think the picture becomes a little clearer if we just go to 8.

Q. Let's go there now.

A. Exhibit Number 8 tries to show the status of each well at -- you know, in February, but in this transition period. And they're lumped into groups, hopefully for our understanding.

So item number 1 says there are 11 wells that we're pumping with enthusiasm because they make enough oil and gas to be economic. So there are really 11 economic wells, and we're pumping those, and they're listed there, number 3, blah, blah, blah, 131. Anyway, the 11 wells listed there, exactly which ones they are.

There are five injection wells from our first try that we're injecting in at reduced rates, but those wells will not be part of the next testing, and they will drift off into limbo-land, unless we can get a real plan set up here. We have three wells that are in real TA status, Number 10, Number 67 and Number 116H

And then come the big groups. There are 60 wells that are not pumping, but they're open to sales, and a little gas comes out which is sold. And so they are producing, but very marginal. And all those wells are listed there, from Number 1 to Number 138.

And under item number 5 there are 22 wells that are not producing -- not being pumped, and they don't produce anything without being pumped. I call them shut-in, and they're listed there from Number 2 to Number 139. Those numbers add up to 101 wells in the unit, in the -- Hopefully we're getting to where we can understand the point of all this.

We want to go -- do a little testing, and then we want to go and inject in a pilot pattern that will involve 10 or so of these wells, but we cannot afford to spend the money to put the 22 shut-in wells back into production and to keep the 60 not-pumping wells alive for the testing period, because some of them will keep producing a little gas and some of them won't.

And we have the five old injection wells which are going to fall into that same pool, and so there's at least -- so the only wells that are really covered are the 11 producing wells and the three TA'd wells, as long as their TA status can be maintained. The other wells are a problem except the ones that are actually in our pilot area. And we cannot afford to keep that 20, 40, 60, 80 wells alive while we do this testing problem, this testing program.

Q. Let's go to Exhibit 9.

A. I don't know what else to say.

Q. What does Exhibit Number 9 show?

A. Okay, Exhibit Number 9 has nine red triangles on it, and it's listed there as Expansion Option 7A. Anyway, it's one of the things that we talk -- well, it's one of the things we talk seriously about management.

Actually, it's the one that the engineering department proposed to management that we do, and it's intended to be an east-west line drive consisting of the bottom two groups of wells, Number 98, Number 99, and 100, and Number 122, 123 and 124, make two east-west lines of wells that would be injectors, the water -- under the idea that the water flows fairly easily east-west, and so it would move between those wells, but eventually it would build up enough pressure to push a bank of water north from the south group and south from the north group, and try to push oil to the three wells in the middle, 109, 110 and 111. That would be an east-west line drive pilot.

And superimposed on it are a diamond shaped four wells on top, consisting of 75, 85, 87 and 99, that are a fivespot surrounding producer Number 86, where that injection would force water towards Well Number 86, basically from all directions, and try and see if that's effective at moving oil.

So the engineering department proposed that we do both these kind of patterns at once, at a capital cost of about $3 million. And Yates management said, That's too much to spend at one time.

Q. And so is your plan to proceed sequentially --

A. So our plan is to proceed sequentially, is to do this testing to determine which of the two patterns has the better chance, and then try the first one of those first, and if that doesn't work probably try the second one sequentially.

Q. The cost of this effort is really what is driving this program and the way it's going to be implemented; isn't that fair to say?

A. The cost and the risk, but the cost, yes.

Q. In terms of trying to control the cost, if you're able to go forward with this, will you be able to use tubing and other material out of existing injectors?

A. Yeah, that's part of the argument for doing them sequentially. We have, you know, lined injection pipe in the five wells that we have been injecting into. That's approximately $50,000 a well.

So we're hoping and we're planning to take that lined injection pipe out of the five current injectors and put it in -- and use it in the -- either in the line drive or the fivespot pattern. I mean, if we do the line drive first, we would have to buy one more string of lined injection pipe to have enough for all six injectors. If we did the fivespot first, which involves four injectors, we would have sufficient lined pipe to do that.

But anyway, by re-using that we can save $50,000 an injection well, which is, you know, another $500,000 over the project. Anyway, we're -- that's one of the factors that argues towards doing the two patterns in series. And of course there's some others --

Q. All right, what is --

A. -- mostly money.

Q. What's Exhibit 10?

A. Okay, so Exhibits 10 and 11 just show the two individual patterns that we would do sequentially in one order or the other.

Exhibit 10 illustrates where the red triangles are injection wells that we would inject into in an east-west line drive, and the capital costs for that project are $1.5 million. It's in the area that it is because it's relatively near to where our water injection station is, but we'd have to lay new injection lines to all these wells, et cetera.

Exhibit Number 11, it's the same thing for the fivespot pattern. It shows the four injection wells that we would inject into, and again it's within a mile of our water-injection station, but you'd have to lay new lines to all the wells and convert them all to injection at an estimated capital cost of $1.2 million.

Q. Let's go to Exhibit Number 12, and I'd ask you to refer to this exhibit and review the economics involved and the proposed testing that Yates is interested in undertaking.

A. Okay, Exhibit 12, the bottom half of it, I wanted to try to make fairly clear what kind of testing we were really talking about, so there's fairly much detail about the testing there.

The top of the exhibit just tries to put that on paper, some of the economic numbers that I've been throwing around, maybe, is how we'd say it. But let's see if we can make that be sensible.

Item number 1 under economics, the unit lost $400,000 per month in 2006. And if we don't do something

-- I mean, the corollary is that if we don't do something different during the next testing period, we will continue to lose something of -- I say $300,000, but something on the order of that per month, and that's a lot of money over the testing periods that we're talking about.

The average operating costs per well are $6000 per well, per month.

The 22 wells that are currently shut in, if we had to put them back on pump and the pumps were free, we would still be spending $132,000 a month just to pump those.

The five injection wells would cost $30,000 a month to pump, even if the pumps were free.

There's 60 more wells out there in a very marginal state, some of which are going to fall into the shut-in status.

If we actually had to pump all those, it would be $360,000 per month, even if the pumps were free. You know, I've tried to make an estimate of how many problem wells we would have over the next three years, and I come out that we're losing about $300,000 per month on just pumping charges to try to hold those wells by producing a little out of them, rather than just leave them sit there, which is what we're proposing that we do.

So to hold the unit at a loss of $300,000 a month for three years is $10 million, which we simply can't afford. It's that clear. If that's the only choice, our options are down to quitting. If the choice is quit or face $10 million of losses during the testing period, the only conclusion from that is quit. Anyway...

Q. Let's go into the --

A. Let's go on to the testing part. This is actually interesting.

The first part of the testing, we'd like to measure oil saturation to two wells, and we've picked two wells. I mean, if you want to look at the map you can see where they are, but they're Number 61 and Number 135. Number 61 is kind of in the middle of the unit, Number 135 is towards the south edge.

The testing procedure that we're talking about was invented by Exxon in the 1960s, when people were talking about surfactant floods, which -- Anyway, it was invented by Exxon in the 1960s, and it really does work. It's been used, not hundreds of times but towards 100 times, and it really does work.

You inject into a well a chemical called an ester. The actual one here is called ethyl acetate. So you inject into a well for a week or two and then let that solution sit there.

Two things happen to the ethyl acetate while it's in the well. Part of it, the chemical word is, hydrolyzes, changes into an alcohol. In this case it would be ethyl alcohol, ethanol, the alcohol that makes people drunk. So part of it changes into an alcohol.

The other thing that happens is that the ethyl acetate -- ester -- partitions is the word I use, partitions, which means that some of it goes in the oil and some of it goes in the water. You inject it in a water solution, but some of it transfers to the oil. And the amount that transfers to the oil depends on how much oil is there.

So you inject this ethyl acetate in water. And after it sits there a while, you've got ethyl acetate in water, you've got ethyl acetate in oil, and you've got this ethanol alcohol that was produced from some of the ester. So then when you produce it back, you get these three components. And the alcohol just stays in the water, and so it comes back first. And the ethyl acetate that went into the oil is held up, and slowly some of it comes back to the producing well.

And so what you're measuring is the time lag between when the alcohol comes back and when the ethyl acetate comes back, and by analyzing that you can tell how much oil there was for the ethyl acetate to spend time in while it was down there in the reservoir.

And that really involves -- usually involves a computer model, but you can -- by measuring how much and when these three chemicals come back, you can estimate fairly accurately how much oil there is down there. And by "fairly accurately" I mean within, oh, about three percentage points by which -- So if you measure an oil saturation of 25 percent, 25 percent of the fluid is oil, the accuracy is such that that means it's between like 22 and 28 percent. So it's 25 plus and minus 3 percent, is the kind of accuracy that you get. So you really can tell for sure whether you've got 35-, 40-percent oil, which would be an attractive target, or 15- or 20-percent oil, which is a very unattractive target.

So I -- anyway... And you can see that it -- I mean, I think from my hand-waving description here, fairly complicated procedure, and not surprising that it costs $70,000 a well, or the estimates have gone up. There's a company out of Laramie, Wyoming, that does these tests, and -- anyway, the cost is $70,000 per well, and I expect it to work. I mean, I think it will really give accurate answers.

Q. Dr. Boneau, once you go through that, that's the first thing that you would do; isn't that right?

A. Yeah, well maybe -- you know, maybe -- well, we know there's a lot of oil down there, it's just with the vugs, is where it is.

But anyway, we did not do these kind of tests before we started the first injection, but now it seems prudent to us to -- Is there really any oil -- is there really oil that's readily available for the waterflood before we do anything else? And it --

Q. And if you got a bad result on that, that could be the end of the project right there, could it not?

A. As item number 4 says, "Low oil saturation could kill entire project." Yes.

Q. Assuming you have a high enough oil saturation, then what do you propose?

A. Then we propose these two interference tests. And then they're -- well, the word "interference" is used, and that -- we can just use that, but basic- -- we're going to inject into one of the old injectors and simply measure the pressure response at a well that's east-west from there and a well that's north south from there, and the idea is simply to estimate the permeability in the east-west direction and the north-south direction.

So these tests are, inject into one well, put downhole pressure gauges in a well offsetting to the east and a well offsetting to the south or whatever, and measure those pressures. If the two wells are connected, the measured pressure should go up, as you inject water. If they're not very well connected the measured pressure may not go up at all, or may go up only a little, or very slowly.

And those -- Anyway, a lot simpler idea than the first kind of test. But you inject for two weeks, the cost is in the downhole pressure measuring devices and in the analysis of the results, but the cost is estimated at $30,000 per test, which would be $60,000 for two of them. Anyway, the two things together, a couple hundred thousand dollars. Probably two to three months to actually do the items, and then by the time you figure out the results and charge ahead with the next phase, you're going to use up four to six months.

Q. And that's the first phase of your --

A. That's the first phase of what I see is the plan for what we're going to do out here.

Q. And then what is the plan?

A. And then as item number 5 says, I would recommend -- or we would try the fivespot first of the patterns, if the permeabilities in the east-west direction and the north-south direction were roughly comparable. If the permeability in the east-west direction is much greater than the north-south permeability, that would indicate, I think, that the line drive had a better chance, and you'd want to do the line drive first.

Q. Is it your belief that you would probably try both approaches, one after the other?

A. I think the target is attractive enough that we would try both approaches, is what I think. I think just spread out the -- well, whatever, spread out the cost and re-use the lined tubing, et cetera, but I think we would try both approaches.

Q. Dr. Boneau, could you identify for the Examiner Yates Exhibit Number 13?

A. Yeah, Yates Exhibit Number 13 is a report dated March 5th, 2007, from the Yates engineering department to the working interest owners of the Dagger Draw Unit. And again, I -- we've gone through a lot of what's in there. It kind of puts in one place a lot of what we said, and we made this report for the working interest owners, and it seemed like sharing it with the Examiner would be a wise thing to do.

Q. Basically, this provides sort of a written summary of the material you have presented and discussed with Mr. Catanach today; is that not true?

A. That's true, and my intention of including it is that it gives him some numbers in a halfway organized place to look at, yes.

Q. Does Yates propose to report back to the Division on the progress as they go through these various phases?

A. We'll do whatever they want. I mean, I -- Like I said, I doubt that they want to give us *carte blanche* to do the whole thing, but I doubt that they want weekly reports cluttering their desk. So if they would tell us what they want, we would provide that. And in my mind, something like a review after 12 or 18 months is appropriate, but we will do whatever they want.

Q. What does Yates propose to do with the wells at the end of the test period?

A. At the end of the test period? We will either have found an injection pattern that has a good chance, or we will have not found such as that. If we have not found that, they will make us, and we will go ahead with TA, plugging, recompleting -- It's a lot of wells. I mean, if everything really fails and we're sitting there with 100 wells to plug, we're going to come and try to reach -- I mean -- are the words ACO? Or whatever the words are. But anyway, agree on a plan for taking care of all those wells in a reasonable time period. You know, a reasonable time period is not six months, but it's not five years. It's a year or two or something.

Q. Would Yates agree to either return the wells to beneficial use or --

A. -- or --

Q. -- arrange to --

A. -- or arrange to do those --

Q. -- put them in compliance under --

A. -- under --

Q. -- a schedule?

A. -- under a set time schedule. If we do find something that has a chance of working, we are going to expand that. And being, you know, honest and straightforward with everybody, we are not in one month going to reactivate 101 wells. But we're going to expand that aggressively, and we'll have to work out a plan with the Commission for reactivating those inactive wells in a -- what we agree is a reasonable way and a reasonable time-frame.

Q. In your opinion, would approval of this Application and undertaking the efforts that Yates is proposing be in the best interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes, it doesn't have a whole lot to do with correlative rights, but it does have very much to do with waste. You know, this is the only way we can see -- or this is a reasonable way we can see to avoid blowing off this 50 million barrels of oil that's sitting in the ground in North Dagger Draw Unit.

Q. Dr. Boneau, were Exhibits 1 through 13 prepared b you?

A. Me and two -- one or -- me and two friends at Yates engineering department prepared those, yes, sir.

Q. And have you reviewed them?

A. Yes, sir.

Q. Can you confirm their accuracy?

A. They're as accurate as I can make them, yes, sir.

MR. CARR: May it please the Examiner, our Exhibit Number 14 is a notice affidavit. Notice was provided to all interest owners in the unit. There were approximately 340 such owners, and we had sent a certified letter to each of them, and I have these here. Instead of cluttering your files with them -- you can have them if you want -- I also have a Xerox copy of all the return receipts that I'd like to file with the affidavit, which has been marked Exhibit 14.

EXAMINER CATANACH: Okay.

MR. CARR: And further I'd like to point out that after we had all of these letters out and the affidavit prepared, we were advised that there were about 20 additional owners that needed to receive notice because of some recent transfers of property interest. They had not been notified, and so we notified those interest owners. And because of that, we'll have to ask that the case be taken -- continued and taken under advisement until April

26th to let the notice period run on those last few. One of the people who they failed to notify, Yates failed to notify was Mr. Randy Patterson.

But we are confident now that we have notified all affected interest owners. And also they've received, all working interest owners, a summery of the report that Dr. Boneau presented.

So with that, I would move the admission of Yates Exhibits 1 through 13 that were explained by Dr. Boneau, and our Exhibit 14 which is our notice affidavit.

EXAMINER CATANACH: Yates Exhibits 1 through 13 and the Exhibit Number 14, the notice affidavit, will be admitted as evidence.

MR. CARR: And that concludes my direct examination of Dr. Boneau.

EXAMINATION

BY EXAMINER CATANACH:

Q. Dr. Boneau, during the test period I kind of want to get an idea of what you plan on doing with the wells. Now I understand the injection wells will be active injection, either in the fivespot or the line drive pattern. You will be actively producing the wells that might be affected by those injection wells? Those will be pumped off?

A. We would be producing the wells that are adjacent to the injectors.

Q. Both -- in all directions?

A. Pretty much in all directions. If I sit down here and tell you exactly which wells we're going to produce, you will catch me in a lie. But I'm looking at Exhibit 11. In the fivespot pattern we would produce 76 and 84 and 100 and 98 and 110 and 86 and 88. You know, we would produce the north-south offsets and east-west offsets. The diagonal offsets, I'm not so sure. Some yes, some no, probably.

Q. Okay. How about the 11 wells that are still economic? Those will continue to be produced?

A. Those will continue to be produced, and if by some reason something else becomes economic, yeah, we -- I mean, yes, we're happy to produce the economic wells.

Q. Okay. The rest of the wells are going to be in just a -- what kind of status? Some are still going to be producing gas?

A. Yeah, our -- I mean, they're going to be in a comatose status. If they will produce some gas, we will let them produce some gas, but we don't intend to pump any wells except the economic ones and the ones directly offsetting the pilot tests that we're doing. I think that's clear and accurate.

Q. Okay, so that will be -- by far the majority of the wells will be --

A. Seventy-five of these wells will be in that comatose -- a little gas or nothing at all state.

Q. Comatose.

A. If it gets the message across, it's a decent word.

Q. How are these wells configured at the present time? They have submersible pumps in them?

A. Not very many of them have submersible pumps anymore. They mostly have rod pumps. Well, I think there are three sub pumps in the whole unit. I mean, of the order -- you know, a handful of sub pumps, but the rest of them have -- a few have no pumping equipment for some reason or other, but most of them have rod pumps and beam pumps. Rod pumps underground and beam pumpjacks on the surface.

Q. Okay. So basically those wells will just be shut in?

A. They'll be shut in. The pumping units will not be moving.

Q. And you said most of the wells have 7-inch casing?

A. Most of the wells have 7-inch casing to 8000 feet, yes. They have 7-inch casing so that they can accommodate big -- so that they could accommodate big sub pumps in the past

Q. Tell me about -- You said the wells were drilled in the 1990s, basically. Have you had some casing failures out there?

A. No.

Q. No casing failures?

A. No, no casing failures that I'm aware of. I considered bringing you a wellbore diagram of 101 wells, and I --

Q. Well, they're basically all the same, aren't they?

A. They're basically the same. A few of them have 5-inch casing, most of them have 7-inch casing, but they're basically all the same, yes. Probably two or three diagrams would cover all of them.

Q. By having the wells shut in for three years or so, do you anticipate any -- is there anything in the wellbore that would cause these wells to become a greater risk in terms of casing failures?

A. Well, the gas at Dagger Draw is sour, there is some H_2S in this, you know. There is -- it is not true that there's no risk. There's H_2S eating on things, and the tubing would be more at risk than the casing, but there is some -- whatever. It's not a totally benign situation, I can't tell you that it is.

We might -- you know, we might pull the tubing and pumps out of the wells, just to protect that. But the casing is going to be basically unprotected, but my opinion is that it's new enough and well enough done in this modern age that it will not fail in three years, and we've had no history of failures to this time.

Q. Would it be uneconomic to actually TA the wells, set a bridge plug and...

A. Okay, it costs $5000 to $10,000 a well to TA a well. In our experience so far, that cost has not been the most galling thing. The most galling thing has been that the TA is set for normally one year, and at the end of one year we're told that you can't continue that.

And so if we could -- I mean -- an alternative that might work -- and it's not what I'm suggesting -- an alternative that might work would be a real TA procedure that would last for the three or four -- for the three-year-plus that we're talking about, and not have us TA for a year, and in the middle of our testing program we've got to go and TA 50 wells or something. You know, I don't want to get into that.

But spending $10,000 to TA 80 wells, $800,000, and then it would cover us for the whole testing period, obviously would be preferable to losing $10 million while we live with the present rules. We think that $800,000 is also a waste, but -- I don't know if management would do that or not, frankly. But that would obviously be an alternative. It might be easier for you to approve and some kind of middle ground. But our management might not want to spend that money. Honestly, I don't know what else to tell you.

Q. Uh-huh. Well, even during the three-year period that you're testing these new patterns, you're still going to be losing money, right? In the unit? Is that a fair assessment, or is...

A. Yeah, but we're going to be losing $50,000 a month and not $300,000 and $400,000 a month. We're going to be losing what it costs to do the testing. We're going to be making a little money on the wells, economic, and we're going to be losing -- you know, if you want to put numbers to it, I'd say we're going to be making $50,000 a month on the economic wells, and we're going to be losing $100,000 a month on the testing program, and we're going to be losing a little money, but that's in the realm of reasonable in terms of gaining the knowledge. The $10 million is not in the realm of reasonable to gain the knowledge.

Q. Is Yates the biggest cost-bearing interest in the unit?

A. Yes, Yates is about 85-percent owner of the unit.

The next biggest owner is Nearburg, with about 5 percent.
Q. Hm. Does Yates have any plans to sell the property?
A. Sell used to be a four-letter word at Yates. It is no longer a four-letter word, we have actually sold a few things, and it's -- so I cannot rule out the possibility of trying to sell this.
Q. The reason I bring that up is because we've had problems with properties like this that go into the hands, you know, of a subsequent operator that maybe can't afford to --
A. Okay --
Q. -- to plug the wells properly --
A. -- well --
Q. -- or --
A. Yeah. I mean, what I think I can say positive is that if our Application is approved and Yates starts this testing program, Yates will not sell -- Yates will not sell the unit until the testing program is over and the analysis of the testing program is over. I think that's -- I think I can say that with a high degree of confidence. I cannot say that five years from now Yates won't sell the whole thing.
Q. Okay. Have you got a figure in mind as to what oil saturation you would need to make this thing economic

to continue with the fivespot, with the line drive?

A. Yeah, if the oil saturation is 35 or above, that's encouraging. If it's 25 or below, that's very discouraging. If it measures 30, I don't know what I'd -- I mean, it needs to be 35 or above to continue testing.

Q. So if it's below 30 you probably won't go on?

A. If it's below 30 we probably won't go on, which means we'd be to the sell, plug, recomplete place.

Q. And those results of that test would be -- I guess you would consent to provide those to us?

A. Yes, sir.

Q. The reservoir here, is it -- it's mostly water. Is there an oil-water contact still in the reservoir? I remember there was a big water column.

A. There's an oil-water contact way deep where there clearly is water below that and not oil. But the main part of the reservoir, which is what we're talking about here, acts like it's in the transition zone, in the whole huge section of the reservoir, including, I think -- I would say, all of this unit, acts like it's water and oil together in the reservoir. And the real oil-water contact is below -- is 100, 150 feet below what we're talking about here, but there's a lot of water here also.

Q. So where was the majority of the oil produced from? The lower interval?

A. No, the majority of the oil is produced from this intermediate transition zone. Hardly anything is produced below the oil-water contact, obviously, but -- so my first -- you know, in the real producing reservoir, which is what we're talking about here, in the transition zone, we produced 25 million barrels of oil and 86 million barrels of water out of the main reservoir.

Q. How thick is that main reservoir you're talking about?

A. It's a number of zones over 200 feet, over an area of 200 feet. The reservoir pressure has obviously been brought down. It's about 400 pounds, 300 or 400 pounds. We need to raise that pressure back up, you know, near its original which is like 3000 pounds.

And in this Phase 1 thing that we talked about, we got the pressure up to like 800 pounds. We were not going to -- anyway, we were not able to get the pressure up over -- We need to get up over 2000 pounds or something, 2500 pounds, in my opinion, to force the oil out of these tight places.

And with this unconfined thing that we chose to do for our first effort, it's unconfined in that the pressure just kind of drifts off, and we are not successful at raising the pressure. I think that's the main -- I mean, to me that's the main statement of the failure of the first thing. We were not able to raise the reservoir pressure by a significant amount.

Q. How large -- On your oil saturation test, how large an interval will you be testing?

A. Oh, well, that -- you know, we selected -- I mean, the wells that are selected, we selected because they have a relatively small producing interval. I mean, the test is going to be more compli- -- well, it's going to be harder to interpret if you've got four zones at 8000 feet and 7950 and 7900 and blah, blah, blah, you know, all producing. The tests are going to be cleaner if you pick a well that's got one main producing zone, and that's the reason that we picked the wells we have picked, that they have one porosity -- one main porosity zone in the wellbore.

Q. How much do you inject? Do you know?

A. Yeah...

Q. Just a -- you might just give me an estimate.

A. A couple thousand barrels.

Q. What kind of radius of investigation does that --

A. Oh, ten feet.

Q. Ten feet?

A. Yes. Five to twenty feet anyway. Ten feet.

EXAMINER CATANACH: Mr. Brooks, do you want to delve into this?

MR. BROOKS: No, I don't think so.

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

MR. CARR: That concludes our presentation in this case.

EXAMINER CATANACH: Okay. All right, there being nothing further, this case, Number 13,893, will be continued to April 26th.

And I believe that's all we have.

This hearing is adjourned.

(Thereupon, these proceedings were concluded at 9:34 a.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 13893 heard by me on March 29 2007.

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 April 1st, 2007.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2010