STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

CASE 10,779

EXAMINER HEARING

IN THE MATTER OF:

Application of Phillips Petroleum Company to qualify five portions of its East Vacuum Grayburg-San Andres Unit Pressure Maintenance Project for the recovered oil tax rate pursuant to the "New Mexico Enhanced Oil Recovery Act", Lea County, New Mexico

ORIGINAL

TRANSCRIPT OF PROCEEDINGS

BEFORE: MICHAEL E. STOGNER, EXAMINER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

July 29, 1993

A P P E A R A N C E S

FOR THE DIVISION:

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I N D E X

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E X H I B I T S

APPLICANT'S EXHIBITS:

E X H I B I T S (Continued)

APPLICANT'S EXHIBITS:

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WHEREUPON, the following proceedings were had at 1:40 p.m.:

EXAMINER STOGNER: Hearing will come to order. Call Next case, Number 10,779.

MR. STOVALL: Application of Phillips Petroleum Company to qualify five portions of its East Vacuum Grayburg-San Andres Unit Pressure Maintenance Project for the recovered oil tax rate pursuant to the "New Mexico Enhanced Oil Recovery Act".

EXAMINER STOGNER: What county is that in?

MR. STOVALL: That's in Lea County, New Mexico, Mr. Examiner.

EXAMINER STOGNER: Thank you, Mr. Stovall.

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 STOGNER: Inasmuch as you're the only parties here, I assume there's no other appearances.

Will the witness please stand to be sworn?

(Thereupon, the witness was sworn.)

MR. KELLAHIN: Thank you, Mr. Examiner.

MR. STOVALL: Mr. Kellahin, may I ask you a question about the style of the case before we --

MR. KELLAHIN: Sure.

MR. STOVALL: This is -- The Application is to qualify the portions for the Recovery Act. And under the Act, actually, what you have to do is qualify a project or get a project approved, and then based upon the approval we determine the -- I mean, do we have the cart in front of the horse here?

MR. KELLAHIN: No, I -- Maybe it's a form over substance, but we have five project areas within the unit, and it's only these portions of the unit for which we seek certification as five project areas.

MR. STOVALL: Are you seeking to get the five project areas approved?

MR. KELLAHIN: Yes, uh-huh.

MR. STOVALL: Oh, okay.

MR. KELLAHIN: The project areas are smaller areas within the --

MR. STOVALL: I understand that. I realize it's a project area within the unit.

But what you're -- I mean, kind of the reading of the Act we've applied, and I think it's particularly applicable to expansions, is, you get a project approved and, based upon that approval, they can qualify for the tax rate, rather than qualifying for a tax rate and then get it approved, you know.

MR. KELLAHIN: No, no, that's not what we intended to do, and if that's what you believe it says we need to fix it.

MR. STOVALL: Well, not being too much of a form-over-substance guy, I just want to make sure I understand you going in so we've got the right thing as the case is presented, it is presented as an approval of the project?

MR. KELLAHIN: Of five separate projects.

MR. STOVALL: Five separate projects, I understand you've got five separate projects.

MR. STEVENS: Yes, five separate integral projects.

MR. KELLAHIN: And then if we're successful in obtaining that approval, the next step is the one that's set up to handle the certification of a positive response within the project area, which is the administrative part.

MR. STOVALL: Expansions always flag some attention.

MR. KELLAHIN: Yeah. Are you and I clear on what we're doing?

MR. STOVALL: Let us proceed.

MR. KELLAHIN: Okay.

EXAMINER STOGNER: I'm still totally lost, but go ahead.

MR. STOVALL: You've looking at a project expansion approval, and we'll worry about EOR later.

EXAMINER STOGNER: Okay.

MR. STEVENS: No.

MR. KELLAHIN: No, the --

MR. STOVALL: Okay, maybe -- Let's go ahead, and just using -- It looks like you've got an exhibit here.

MR. KELLAHIN: I don't want to use the wrong words.

MR. STOVALL: Okay.

MR. KELLAHIN: We have a waterflood project.

MR. STOVALL: That's been approved prior to --

MR. KELLAHIN: That predates March 6th of 1992.

MR. STOVALL: Okay.

MR. KELLAHIN: It's an old project.

MR. STEVENS: And the CO_2 recovery project --

MR. STOVALL: Okay, excuse me, I am going to ask -- I understand -- We'll give you a chance to explain. But just for convenience of the record --

MR. STEVENS: Okay, I won't say anything.

MR. STOVALL: Yeah, it's just a lot tougher for him to keep track of it, since you're not even identified and sworn yet --

MR. STEVENS: Okay.

MR. STOVALL: -- I mean identified and introduced --

MR. KELLAHIN: The project, so we're not using it in the wrong terminology, the unit and the waterflood project predate March 6th of 1992.

MR. STOVALL: Correct.

MR. KELLAHIN: After the waterflood, there is a part of the unit that was subject to and approved for CO_2 enhanced oil recovery, which also predates March 6th of 1992.

MR. STOVALL: Okay.

MR. KELLAHIN: What Mr. Stevens and Phillips has done now is analyze the success of the unit's CO_2 and waterflood projects, have identified portions of the unit area, which they want to come into and make significant changes to go after additional enhanced oil.

He's identified a portion of the unit being five individual project areas.

MR. STOVALL: Now, for our conversation, let's look at -- I assume it's Exhibit 1 here?

MR. KELLAHIN: Yes.

MR. STOVALL: Those are numbered, 1, 2, 3, 4 and 5?

MR. KELLAHIN: That's the project areas that we're seeking to have certified as expansion areas, if you will, under your Order 9789.

MR. STOVALL: Well, my question then -- and this is where the form gets somewhat significant -- is, Are those approved for the process that you wish to apply?

MR. KELLAHIN: No.

MR. STOVALL: Do you have the authority at this time to apply the process?

MR. KELLAHIN: No, we don't.

MR. STOVALL: Okay, good.

MR. KELLAHIN: Because there are additional injectors to be drilled.

MR. STOVALL: So you are not just seeking approval of a previously approved process or project, referring to 1 through 5 as the project, if you will. You are seeking approval for the process which you propose to use in each of these five project areas?

MR. KELLAHIN: That's right, and if --

MR. STOVALL: And assuming that approval is granted to qualify it for the project -- for the EOR tax rate?

MR. KELLAHIN: That's right. And so what we're hoping to accomplish, if we persuade you, is the approval of the expansion and then the qualification of these five project areas for the reduced tax rate.

And then Mr. Stevens will make sure that he's got the paperwork for the injection wells, you know, that the C-108 stuff. That's not rolled into here, because we haven't filed for those yet.

MR. STOVALL: In other words, those would be filed for the specific wells under the authority granted out of this hearing to -- for this new process and project?

MR. KELLAHIN: And there's no reason to do those unless you agree with us that this is an expansion and a change of technology for these five areas.

MR. STOVALL: Proceeding that way -- That's what I meant, is, the first part of the process is to get approval for the project itself --

MR. KELLAHIN: Yeah.

MR. STOVALL: -- as a recovery project, and then we'll -- At the end of the hearing we'll qualify it as a tax project.

MR. KELLAHIN: That's right.

Mr. Stevens has come to the engineering conclusion that these five areas represent a significant change in geologic area and in process and technology, and if Mr. Stogner and the Division agree to these substantial changes, then we also want to qualify them as project areas under the EOR. I think we're saying the same thing.

MR. STOVALL: I think we're there.

MR. KELLAHIN: Okay, let me give you so that you have in front of you, if you don't already, a copy of the Division Order Number R-9789, which is the EOR procedure.

EXAMINER STOGNER: Now, what is 9708 that's referred to in the ad?

MR. STOVALL: Well, our -- Mr. Kellahin --

MR. KELLAHIN: What did I give you? The wrong order?

MR. STOVALL: Yeah, you gave us 9789 --

MR. KELLAHIN: I'm sorry.

MR. STOVALL: -- which is Marathon.

MR. KELLAHIN: I'm sorry. What I need to give you is 9708, which is the -- that's the Marathon expansion order.

And you may want that also as a point of reference in today's discussion.

MR. STOVALL: This is the one which we denied in the expansion?

MR. KELLAHIN: That's right. And what I need to also give you is the one that sets up the expansion unit.

MR. STOVALL: I can't wait till the nomenclature. What can we do with that one?

MR. KELLAHIN: We'll get it right here in a minute. Here's 9708.

EXAMINER STOGNER: You want me to just use this as a point of reference and not utilize it as a model; is that what you're saying?

MR. KELLAHIN: That's right.

EXAMINER STOGNER: The Marathon order? Okay.

MR. KELLAHIN: I wanted -- Because Mr. Stogner has not dealt with these kinds of cases before, I wanted you to have available as a point of reference the Division procedure, which is 9708.

The only order I'm aware of that touches on this concept is the Marathon order. And if that gets to be a part of the discussion, Mr. Stevens is here to explain to you why he thinks his project is substantially different than the one Mr. Catanach denied for Marathon.

MR. STOVALL: Off the record.

(Off the record)

EXAMINER STOGNER: Okay, let's go back on the record.

MR. KELLAHIN: With that introduction, then, let me call Mr. Jim Stevens.

JIM STEVENS,

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. Stevens, have you been sworn?

A. Yes, I have.

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

A. My name is Jim Stevens. I'm a reservoir engineer for Phillips Petroleum.

Q. Would you summarize for us what has been your educational background?

A. I graduated from Louisiana State University in 1980 with a bachelor of science in petroleum engineering.

I started work for Phillips Petroleum Company in June of 1980. I worked a year in Houston in a drilling position, worked three years overseas in Norway in drilling and production assignments, and I've worked since 1984 in Midland-Odessa with production and reservoir-engineering assignments.

Since September, 1991, I've been the reservoir engineer for the East Vacuum Grayburg-San Andres Unit.

Q. Since what year, sir?

A. September, 1991.

Q. In addition to being the reservoir engineer for this particular unit, were you also in attendance at the Oil Conservation Division hearing of the OXY application that was heard a few weeks ago in which they sought an enhanced oil recovery tax rate to be applied to their project?

A. Yes, I was.

Q. Have you made yourself familiar with the Division Order R-9708, which is the procedures and rules for qualifying a project area for the reduced tax rate?

A. Yes, I have.

Q. Have you made a study of your project area in terms of those rules and regulations in order to reach a conclusion about whether or not these five project areas should qualify for the credit?

A. Yes, I have.

Q. And what, after all that study, is your ultimate conclusion?

A. That we are going to make a significant expansion to our project into portions of the reservoir not previously contacted by CO_2.

MR. KELLAHIN: At this point we tender Mr. Stevens as an expert reservoir engineer.

EXAMINER STOGNER: Mr. Stevens is so qualified.

Q. (By Mr. Kellahin) So that you can orient us as to your unit, let me have you direct your attention to what is marked as Exhibit Number 1.

A. Exhibit Number 1 is a plat of our unit showing the complete unit area.

The CO_2 project area encompasses about 5000 acres, and that's Sections 29, 28, 27, 26 and to the south.

The far northern portion of the unit is not in the CO_2 project area.

It also highlights the five separate project areas that we're looking to qualify today.

Q. What's the color-code used to identify the five project areas?

A. We have an aqua coloring that circles each one of the project areas.

We have blue infill wells noted.

And we have a green triangle showing the producing wells we want to convert to injection wells.

Q. Let's set aside our locator plat, Exhibit Number 1, for a moment, and let me have you direct your attention to Exhibit Number 2.

A. Exhibit Number 2 is a list of wells in the expanded use area. It's divided out into each project area, 1 through 5, showing the producers and the injectors.

You might notice that some of the producers are common to areas 3 and 4.

The back several pages are a detailed geographic description of the project areas.

Q. If the Division decides to approve this Application, then Exhibit 2 could be utilized to provide the written description for each of the five project areas and would identify the producing and injection wells that are affected?

A. That's correct.

Q. Okay. Before we get into the specific details of the history and then what you're proposing, I'd like you to help us set the geologic stage in which this unit has been developed.

To do that, let me ask you, Mr. Stevens, to turn to Exhibit Number 3, and let's fold that out.

Let's start with the A-A' cross-section, Exhibit Number 3, and have you help us understand the geologic environment in which this unit has been developed.

A. This cross-section, A-A' is a northwest-to-southeast cross-section through the unit.

This cross-section shows the nomenclature that we have assigned to different layers in the reservoir, A through I, A through E being the Upper San Andres, and F being the Lovington Shale, G, H and I being the Lower San Andres.

Also on each one of these log traces we have highlighted in blue and red different types of porosity.

Blue is porosity that's less than five percent, what we consider tight and a barrier.

The red cross-hatching is porosity greater than five percent and what we consider a pay zone.

When you look at the location map on the far left, it will give you a better idea as to how it cross-sections through the reservoir.

Q. What is the unitized interval, for purposes of the unit?

A. The unit- -- It is the Grayburg-San Andres, from approximately 4250 down to about 4800 feet.

Q. Okay.

A. The biggest point to get out of this cross-section is, if you pick one layer and you were to follow that layer across the reservoir, looking for the discontinuity in the pay zones, both -- in the barriers and both in the pay zones, we see it in whichever cross-section we look at, either A-A' or B-B'.

The end result of this detailed geologic analysis that we've come up with is that this reservoir is very baffled. There are discontinuous pay zones and discontinuous barriers.

And that's a very different change in our geologic understanding than what we had when we set the project area up.

Q. Let's turn so that you can identify for us Exhibit Number 4, which is the B-B' cross-section.

A. B-B' is a very similar cross-section. It has the same coloring scheme, same nomenclature.

This is done with a program called Stratilog.

And if you were to pick one layer, if you were to pick, say, the E zone and take it across, you can look for various changes in porosity across the reservoir, showing the baffled nature of the reservoir.

This leads to poor sweep efficiency, and sweep efficiency is vitally necessary in CO_2 flood.

It's very, very different than a waterflood or primary recovery.

Q. What kind of formation are we dealing with? Is this a carbonate or a sandstone reservoir?

A. This is a dolomite, Pennsylvanian-aged dolomite that was laid down.

And each one of these layers, A through E, is a specific stratigraphic unit.

You can map that layer all the way across the unit. However, the pay within each individual layer is very discontinuous.

So that's how we have organized these layers, A through I.

Q. All right.

A. It's very important to understand the baffled nature of the reservoir and understanding the mechanism of waterflood recovery and CO_2 recovery, to understand why we're here today asking for the EOR tax credit.

Q. When you identify this as a baffled reservoir what does that mean to you?

A. Well, if it's a baffled reservoir, there is a slight amount of continuity between it, but very, very limited.

If you were to drill primary wells into a baffled system, you can draw down the pressure in a baffled system. You can likewise drill injection wells and pump water into a baffled system and repressure it up.

But if you don't have your wells located properly in a baffled system, you can't sweep from one well to the other, because there's multiple barriers in between a lot of the wells.

The only way to get proper sweep efficiency in a baffled reservoir is to reduce the well spacing so that we can contact the wells together.

Q. Let me have you now turn to the next display. It's Exhibit Number 5. What are we looking at?

A. Exhibit Number 5 is a 3-D representation of our pay. The easiest way to look at it is to hold up Exhibit Number 6 with it.

Exhibit Number 6 is a plan view of the same map, using the same color scheme.

This 3-D image tends to highlight the discontinuity we have in the reservoir. You can visualize the good peaks in pay as well as the poor valleys, and you can also see how the poor valleys and the good peaks occur right next to each other.

MR. STOVALL: Just understanding this, would you explain what the coloring means?

THE WITNESS: The coloring --

MR. STOVALL: And if I were to sit and pick up your written word here and read it and look at this exhibit, what would I have to be looking for to understand it?

THE WITNESS: The higher the peak, the better the net pay.

MR. STOVALL: Okay, so color isn't significant? That's just --

THE WITNESS: Color -- There is a color assigned to each different value in net pay, red being the best -- I believe that's over 200 feet -- proceeding down to where the purple is the poorest.

So it's to give you a visualization of peaks, meaning that's a lot of net pay. So it grades from red to yellow to green to dark blue to purple.

And this map is similarly positioned with the very first exhibit so you can get an idea of where the net pay is in the reservoir. Most of it exists in Section 32 and Section 33, which is where the project areas are that we're talking about today.

Q. (By Mr. Kellahin) With Exhibits 5 and 6 in mind, now, turn to Exhibit 7 and identify for us what we're looking at in this display.

A. Exhibit Number 7 takes one of the layers, layer E, and represents the pay quality as a ratio of net pay to gross pay.

So what we end up with is a map showing zero to a hundred percent, a hundred percent representing that all the pay in that area of the -- all the thickness in that portion of that zone was pay. Less than 40 percent means it has very poor pay quality.

This is very similar to taking a cross-section through the 3-D picture, if you were to take a planar view of it.

And what is distinct about this map is, the red represents good pay areas, greater than 70 percent. And the blue represents poor pay areas; less than 40 percent of the pay in that zone is good pay.

And if you look at the nature of how the circles line up, they're almost random in the way they line up. It goes from bad to good, to bad to good, to bad to good. So it shows the discontinuous nature of the reservoir.

This was knowledge that we didn't have when we set up the CO_2 flood back in 1984 and 1985. This is the result of a very recent geologic study that we started in 1991 with our foam project that we're partners with the State of New Mexico on.

Q. Mr. Stevens, let me have you turn now to Exhibit Number 8 and have you identify and describe that display, please.

A. Exhibit Number 8 is another unit map. Highlighted in red are infill wells we drilled in 1988. There was ten ten-acre infill wells.

Highlighted in blue are the infill wells we plan to drill this year.

And in green are the same producing wells we want to convert to injection.

The purpose of this map is just to give you an idea of the locations of the 1988 wells with our 1993 wells.

Q. Let me have you turn now to Exhibit Number 9. What have you plotted on this display?

A. On Exhibit Number 9, what we have is a subset of wells where we've taken out the 1988 infill wells and all the offsets to the 1988 infill wells, so that this plot represents production behavior, completely independent from anything we did in 1988.

Now, to completely understand this plot, let me briefly go over the unit history so it will set the stage so you know what happened here.

This field was discovered in 1929 by the Socony Vacuum Oil Company. Primarily depletion in the unit area started in the 1930s. So it's been under 60 years of depletion since it was originally discovered.

There have been various injection projects begun in the field in the early 1970s.

The East Vacuum Unit was formed late in 1978. Our water injection started in 1980. Therefore, you can see the response from the waterflood there and the oil response and also the increase in the water production on the plot.

Q. When did you start CO_2 injection into the unit?

A. We started CO_2 injection in September of 1985.

But before we started water injection, our average reservoir pressure was only 560 pounds. So prior to 1980, this area had gone under 50 years of depletion.

And if I was to quote the definition in the Order, R-9708, that defines what primary recovery is, it means the displacement of crude oil from an oil well or pool classified by the Division into the wellbore by means of the natural pressure of the oil well or pool, including but not limited to artificial lift.

This reservoir has no natural pressure lift in it. The pressure when we started our waterflood was 560 pounds. We re-pressured the reservoir to 2100 pounds, so that our CO_2 would be miscible, would be in a liquid state in the reservoir.

Our CO_2 flood began in September, 1985. We have a two-to-one WAG cycle -- "WAG" refers to water alternating with gas -- so we put in eight months of water and follow it with four months of CO_2.

Our project plan was to inject for 17 years at 30 million cubic feet per day of CO_2, which would result in a 30-percent four-volume slug of CO_2.

And what was most important was, we were going to do this into inverted 80-acre ninespots. That means a center injector, surrounded by eight producers. That results in 20-acre spacing.

The basis behind our whole CO_2 flood was a simulation done in 1984 where we simulated one-eighth of an 80-acre ninespot, which would be the equivalent of a ten-acre slice of a pie. We took this ten-acre slice and expanded it out to a 5000-acre project area, and that was the basis for our CO_2 plan back in 1985.

What we want to present today is a significant change from that project plan.

Q. Describe for us so that we can have it clearly in mind what the significant change is in terms of method, from what was previously done to recover oil within the unit.

A. Well, from the beginning of our CO_2 flood, we managed our CO_2 flood on a project area or on a WAG area, on much more of a macroscopic level.

We're now changing to individual pattern management, because what we have determined is that each pattern tends to act like its own separate reservoir. So we have set our whole unit up where we track the production and injection on a pattern basis. We have all the patterns named, and we track them in a production analyst's data base. That's one of the changes that we're making. This change is based on a new and much better understanding of the reservoir geology.

We need better sweep efficiency from infill wells and injectors, or we will not recover the oil left in this reservoir.

Q. What was your method that you applied to identify the five project areas that are the topic of discussion this afternoon? Is there a criterion?

A. There's a combination of our pattern management, where a pattern is the smallest level of management we can do and properly account for CO_2 injection. That, along with a streamline model, which I will show results of here in a minute, that shows changes in flow patterns in a pattern, from the effects of infill drilling or changing injectors to producers.

And the streamline model will show significant changes in the flow patterns in the reservoir.

So really, to summarize, we've changed our plan from three major standpoints.

Historically, this will be the first change we've made in a project plan since the beginning of the project plan. There have not been any conversion of any producers to injectors since we started our CO_2 flood.

Financially, this is a major change. For us to recover the residual oil left in the reservoir will require an enormous amount of capital.

And thirdly, there's a reservoir engineering change because we're changing the flow process in the reservoir significantly.

Q. Have you estimated for us the cost of the project?

A. Yes I have. It's approximately -- a little over $5 million, I believe.

Q. The Application which contains your verification indicates on page 7 total cost for the project. What numbers did you provide?

A. $5,976,249.

Q. And those represent your own calculations and your own estimate of costs?

A. That's correct.

Q. Okay.

A. So with that background of our unit, it's important when we look at this production plot to understand where we started CO_2 flood and notice in 1987 -- late 1987, there's a production peak.

It also corresponds with our gas production. In a CO_2 flood your gas breaks through fairly rapidly into your producers, and that shows a response to CO_2.

So what we have -- From late 1985 to late 1987 we have an increase in production and a stop in the decline. Then production peaked in late 1987.

The reason that is significant is because on the next plot, Exhibit Number 10, we're going to show the nature of the 1988 infill wells and the nature of the offset wells.

When you look at this Exhibit Number 10, you see the black curve are the offsets to the 1988 wells.

The red curve is the production from the 1988 wells.

You'll notice an increase in production associated with our CO_2 project, till about mid-1987, and then a flattening of the decline from that point onward.

That peak in production, that stop in

increase in production, is not because of the 1988 infill wells; it's a result of the CO_2 flood. It was simply a coincidence that this production peaked at the same time we started our 1988 infill program.

That's very important, because what we want to establish is that these 1988 wells were finding new reserves. We are not accelerating any reserves. These are new reserves that we would not have recovered otherwise unless we had drilled this well.

Q. Well, are they new in terms of being additional primary recovery?

A. No.

Q. Okay.

A. No, primary finished back in the Seventies when our reservoir pressure was depleted.

The pressure that now exists in the reservoir was there from injection, either from the waterflood project or our CO_2-flood project.

So these are new secondary and tertiary reserves that we're recovering with our 1988 wells.

This 1988 program, looking at the data over five years, gives us a lot of confidence that we are not sweeping the reservoir correctly. There's a lot of oil there, not in contact with the current set of production wells. And the only way for us to contact new portions of the reservoir with CO_2 and get an improved sweep efficiency is to drill more infill wells.

Q. Let's take, before we look at each of the five areas, project areas, let's take a moment and have you tell us how you went about deciding the size and the shape of each of the project areas and what method that you applied to decide that what change in technology would improve the sweep efficiency for those project areas.

A. Each one of the project areas is based on an injection-pattern basis. That's the smallest unit that we try to manage.

Basically, when you inject CO_2 into the middle of a pattern in a homogeneous reservoir, you would benefit all the wells in that pattern.

So we ran a streamline model, based on each one of the patterns, that gave us an indication, a visual indication of the change in flow, for making changes in the reservoir, such as drilling an infill well or converting a producer to an injector.

This is an internal program, a Phillips Petroleum program. It's based -- and if I might read just a few sentences, it's a very short summary of what this model is that we're going to talk about here in detail.

It's a visualization of the overall flow pattern of a reservoir. It can be accomplished with the streamline motion.

The program gives a quantitative description of the flow paths in uniform, homogeneous reservoirs which can be used to judge the effect of infill drilling or rate changes in an injection project with arbitrary well locations and rates.

The stream lines are determined by tracking a particle of fluid through the reservoir to its destination. This determines one stream line. And by tracking distributed particles, the entire network of flow paths can be determined.

The calculations assume that the reservoir is homogeneous, of infinite extent, with the wells treated as point sources or sinks, and the fluid flow is assumed to be single-phase, steady-state and comprehensible, like most streamline models.

In --

Q. Let me ask you some questions about the model.

You've described for us a reservoir that is very heterogenetic --

A. Yes.

Q. -- discontinuous, this baffled complex reservoir, and yet you're applying to it a very simple one-layered homogeneous simulation?

A. Correct.

Q. Okay.

A. This program is only meant to show a visualization of what would happen in a perfect environment, if you had a homogeneous reservoir.

It's almost indicative of one layer in the reservoir, if that layer was continuous, which we know it is not, as I've shown in the earlier exhibits.

It's a very simple model, based on known engineering principles. That way there's no unknowns in this model.

But it will not necessarily reflect reality, because there may be permeability barriers or other barriers in the reservoir we don't know about.

It's a very simple visualization of what can happen if you change injection rates.

Q. What is the purpose, then, of applying this model to each of the five project areas?

A. It will give us a visualization or an approximated effect in one flow pattern from either infill drilling or changing injectors to producers.

It's used as a guide, not -- in a qualitative sense, not in a quantitative sense.

Q. Are you satisfied as a reservoir engineer that the application of this model will give you an accurate method of forecasting the probable expansion area that you're seeking to have the Division approve under the EOR procedure?

A. Yes, I do.

Q. Once you identify the project area, then, by the model simulation, you can be comfortable as a reservoir engineer that the wells contained within that project area ought to receive some type of response or effect by your change in process or technology?

A. That's right. We cannot guarantee that every well will be affected, but it gives us a very good idea as to the probability of affecting all the wells in that pattern.

Q. You've read the Division rules with regards to EOR projects contained in Order R-9708. Does that, in your opinion as a reservoir engineer, satisfy the criteria for --

A. Yes, I do.

Q. -- for approving of these project areas?

A. I believe it does satisfy the criteria because it talks about expansion of a geologic area, and we have conclusively proved with our 1988 wells that there are large portions of the reservoir not in contact with CO_2. And if we don't drill these infill wells, those portions will probably never be flooded with CO_2.

CO_2 has a much different recovery mechanism than water. It must touch the oil to do any good. Water injection projects simply has to pressure up the reservoir, and you can get substantial recovery from it. But a CO_2 flood relies a lot on areal sweep for it to be effective.

Q. Let's take, now, the application of the modeled procedure, using the simulation from your computer, and apply it to project area number one.

And look at Exhibit 11 and show us, first of all, your proposed project area for project one.

A. We set up on a pattern basis project area 1 and ran our model. We included not only the wells in that pattern, but also one ring of wells around the pattern so that it shows the effects of the -- one ring of wells outside of the patterns.

We did it twice, one in red and one in black, so that we could highlight the changes in the reservoir.

Q. All right. You've now moved to Exhibit 12?

A. To Exhibit 12.

Q. Exhibit 12, then, is the wells within project area one?

A. That's correct.

Q. You have simulated the effect of the change of process or technology within that project area?

A. That's correct.

Q. The lines in black represent what?

A. The lines in black represent stream lines if we had continued current operations.

Q. If you didn't do anything, if there's no change, then the lines represent what occurs?

A. That's correct.

The lines emanate or start at the injection wells and are drawn out to the producing wells.

Q. All right. By applying the model simulation, then, taking into consideration the change of process and technology that you're seeking to do, what happens?

A. Well, as we see on this graph by the multitude of red lines that show up, by putting in an infill well there, on 0524-007, we're sweeping a large area of the reservoir. And by changing that 129 well to injection, to CO_2 injection, we cover much more of the reservoir.

This pattern has not been under CO_2 flooding at any point in its life.

This is not only an internal expansion; it's also a geographic expansion of our project area. The closest CO_2 injector was this one in the far north, 24W1 and 24W6.

So by converting well 0129 to CO_2 injection or to WAG injection, we create a new pattern here. We drill an infill well down here to the south in an area of large net pay and also close off the reservoir. We want to make sure our CO_2 doesn't exit out that side.

We see a change in the red lines even far from our pattern, because when you change -- especially in a homogeneous reservoir. This may not happen in real life, but in a homogeneous reservoir when you make a pattern change on a stream line model that's based on voidage, it makes a change over whatever affected area it is. It may be outside of the pattern.

Q. Well, let's follow that contrast. If you're waterflooding a sandstone reservoir of uniform quality and thickness, you're going to find an injection response or pattern that is regular and uniform?

A. Correct, predictable.

Q. You can see a predictability about the impact of additional injection wells and the relationship with offsetting producing wells?

A. That's correct.

Q. Contrast to the complexity of reaction or effect that you see in your reservoir in project area one as to what happens with the change in process.

A. Yes, this stream-line model is mainly controlled by rates, or voidage rates, and it gives us a good visualization of what will happen once we make this change in the pattern and produce a new CO_2 injection pattern.

Q. When you're looking to have a project area certified and you're looking at what we've identified as project area one, are you satisfied as a reservoir engineer that you've correctly identified an area that is going to be affected by the change in process, or an additional exposure geologically to the reservoir?

A. Yes, I'm very well satisfied. We've only included those wells immediately adjacent to the injection change.

Q. Okay. Let's go to Exhibit Number 13 and have you identify and describe that display.

A. Exhibit Number 13 is a production plot of the wells in project area one, only those wells that are shown on Exhibit Number 11 in blue.

It shows a predicted rate if we were to continue with current operations. And the large built-in black circles are what are my forecast or prediction from doing the work that I outlined previously in project area one.

We show currently that that pattern is producing about 110 barrels of oil per day.

We're looking at about a 60-barrel-per-day increase from the offset wells, a 75-barrel-per-day increase from drilling an infill well, and I'm hoping that the new production after this work is over will result in about 245 barrels of oil per day.

Q. The forecasted positive effect of the change of process in project area one is shown how on Exhibit 13?

A. The forecasted positive response is shown with the solid black lines, the solid black circles connecting the black line. The hollow black circles are a forecast of what would happen if we do not do anything to the pattern.

Q. And for project area one, one of the changes is an additional injector well, the effect of which is shown by the red stream lines on Exhibit Number 12?

A. That's correct.

Q. Have you conducted a similar analysis and reached similar conclusions with regards to the other four project areas?

A. Yes, I have.

Q. Without belaboring the discussion, let me just turn you loose and have you take us through each of the five areas, starting first of all with the locator map, telling us where we are and what you hope to attain with the change in process.

A. Okay, in project area two, we included two patterns.

We show on our locator map we're drilling three infill wells and converting one well to injection. We simulated that on our stream-line model. You can see where the new number come out in red, 2913, 0221 and 0220. And the streamline model then represents the change in those two patterns from performing that work.

If we carry on, then, Exhibit Number 16 shows my forecast of what that change will do in that pattern.

Q. It also shows you a tabulation of actual historic production of both gas, oil and water?

A. That's correct.

Q. Okay, continue.

A. What we see in this project area number two is an increase from -- currently producing about 700 barrels per day, of all these wells, to a possible increase of up to 1020 barrels per day after this work is performed.

If we continue on to project area three, project area three is a similar project except that it's a larger area because we're converting a middle producer to an injector and changing it into a line drive. It's a very significant change from an inverted ninespot to two 80-acre patterns turned into a line drive.

This shows significant changes in sweep as shown on the stream line model. Previously in this pattern, we were not sweeping the whole reservoir. With changing to a line drive, we believe we'll sweep new areas of the reservoir, as well as drill three infill wells which will also contact portions of the reservoir not previously contacted.

Likewise, there's a production plot, Exhibit Number 19, showing the potential increase in solid black circles and the production history in that pattern.

If we carry on, project four is very similar to project three. We are converting a middle producer to an injector, creating a three-injector line drive and drilling an infill well, which also shows up on the stream lines as increased sweep in the reservoir, as the red lines show up behind the black lines.

It's important to note when you look at the stream line model, there's a lot of wells there in that model.

What I did was, I included the production rates and injection rates for one ring of wells all the way around there. But to make the plat easier to look at, I simply turned off the stream lines on the far -- on the periphery injectors around there, because we want to focus on the change only in the project area. If I was to include all these other stream lines, it would be a very clouded picture and it would be hard to notice just the change in the production area.

But it's important to note that the production rates and the injection rates for one row of wells all the way around the project area were included in the calculations for this.

Then Exhibit Number 22, we show a production plot showing the production history of project area number four, and the potential increase shown with solid black circles from doing that work in project area four.

Moving on to project area five, we have another similar line drive where we're converting a producing well and creating more sweep in that pattern.

The current system we had was not -- is not recovering enough oil from that pattern. And for us to recover the oil from that pattern, we need to make a change in the injection scheme. So we're going to a mini line drive in that area where we have two injectors in a row. It's going to create more of a line drive to the external producers.

It's important to note, as I pointed out in the geologic testimony earlier, that our reservoir is so heterogenic that each pattern tends to act independently from the pattern right next to it.

So there's not one uniform, all-encompassing injection scheme that will suffice for our reservoir. We need to have an individual plan for every pattern in the reservoir.

Then finally there, Exhibit Number 25 is also my prediction as to the production that may be recovered from producing a change in the injection in that pattern.

It's important to note also that we have one royalty owner under this lease; it's the State of New Mexico. From the incremental oil that I forecasted for these five project areas, just the incremental oil, the royalty to the State of New Mexico will be approximately $5.6 million. This is based only on a ten-year forecast. This work will probably go -- have an effect much longer than ten years.

Q. What is your estimated additional incremental oil attributable to the change in technology for the total of all five projects?

A. The total of all five project areas, in ten years, it would be about 2.2 million barrels. Over, I believe, a 15-year life I estimated -- or excuse me, a 20-year life, it was 2.8 million barrels.

Q. Summarize for us now, Mr. Stevens, what has caused you to reach the engineering conclusion that your changes for each of these project areas are something substantially different than simply a continuation of an existing project.

A. We have not made a major change in our injection plan since we started CO_2 injection in 1985. That plan was based on recovering most of the oil in inverted 80-acre ninespots. It was based on a very limited knowledge of the reservoir.

We have come to a much better understanding of the reservoir now. With newer technology, newer geologic mapping techniques, we understand the reservoir very much more, and we have determined that without infill drilling we will leave a significant amount of oil behind.

With CO_2 flooding it is vitally essential that you have good sweep efficiency and the CO_2 contacts the oil. It's much different than a waterflood project.

Q. The initial development of the secondary recovery on the inverted 80-acre fivespot pattern was based on what kind of assumptions, both geologically and from an engineering aspect?

A. Well, they had -- Based on the state of the art in 1984, based on their geologic analysis, they estimated a certain recovery from the reservoir, through the CO_2 process.

But at that time it was never envisioned to infill drill the reservoir. That was not a portion of the plan or even thought of as a likely candidate for the future.

Q. Had the level of sophistication of geologic investigation determined the complexity and the baffled nature of the reservoir?

A. Not to the same understanding that we have now. We have a much better understanding of the geology, and we can better visualize it so that we can take it and act upon it.

Q. If the Division approves your Application for the expanded project areas, summarize for us why this constitutes a significant change in the area contacted by the injection wells.

A. We have significantly, positively, concluded with our 1988 infill wells that we were not contacting portions of the reservoir we contacted before. So the effect of this infill well will be to expand our project area internally to areas of the reservoir that would not have been affected by CO_2 flooding.

In my mind, that is definitely an expansion of the project area, because without this expansion we would leave oil behind and waste our recovery.

We're also significantly changing the flow patterns from large patterns to smaller line drives and inverted 40-acre ninespots. It makes a significant change in the flow patterns in the reservoir.

It also requires a significant investment on the part of the operator.

Q. Have you now developed the expertise that you did not previously have in order to specifically locate the optimum place to put these additional injection wells?

A. We have a much better knowledge or understanding as to where to place these wells, that we didn't have before.

MR. KELLAHIN: That completes my examination of Mr. Stevens.

We move the introduction of his Exhibits 1 through 19, I believe -- No, I'm sorry, it's 25, 1 through 25.

EXAMINER STOGNER: Exhibits 1 through 25 will be admitted into evidence at this time.

EXAMINATION

BY EXAMINER STOGNER:

Q. I'll ask the obvious. Nowhere are you proposing to increase the size of this expanded area; is that correct?

A. Yes, we are increasing the size of the expanded area in project area number one. Geographically? Is that what you meant, Mr. Stogner?

Q. Yes, geographically.

A. Geographically, if you will return to the first map, to Exhibit Number 1 --

Q. Then maybe you should explain to me what the blue line is, the dark blue line.

A. The dark blue line around the unit?

Q. Yes.

A. That is the unit boundary. From an operating standpoint, we are moving CO_2 into a new portion of the reservoir. We're staying within our unit boundary; that's for sure. We're staying within our unit boundary.

But we are creating a new CO_2 injection well into an area of the reservoir that did not have one.

It's an expansion from the operating standpoint that we're moving CO_2 into a new area, not from the unit outline, though.

MR. STOVALL: What you're saying when we're talking geographic area, it is all occurring within the unit and the previously approved waterflood area?

THE WITNESS: Correct.

MR. STOVALL: Measured horizontally on a surface map?

THE WITNESS: Correct.

Q. (By Examiner Stogner) And when you proposed CO_2 injection back in 1988, and that's when -- the day that CO_2 was approved, right?

A. It was approved by an order in probably early 1985. We started CO_2 injection September, 1985. I'm not sure of the exact date of the order.

But we included -- You're correct, we included this whole area into the original CO_2 project area, but we did not inject any CO_2 into that portion of the reservoir.

Q. But you were authorized to?

A. That's correct. As I read this order, it talks about the geologic area, an increase in size in the geologic area, and from that standpoint I was calling that project area one a geographic expansion. That geologic area has not undergone CO_2 flooding before.

MR. STOVALL: I think for the purpose of making sure we understand questions, when you're referring to it, "geographic area" refers to map, within a horizontal map; "geologic area" is reservoir contact, as you're talking about it?

THE WITNESS: Correct.

MR. STOVALL: Either vertical or horizontal?

THE WITNESS: Or horizontal, correct.

It does mention there in the order, under number four, an expansion, extension or increase in the size of the geologic area or adjacent geologic area. So it obviously is inferring an internal expansion of the geologic area. In my mind --

Q. (By Examiner Stogner) Well, I don't think that's obvious.

A. In my mind it does.

Q. Well, in my mind it does not, so right there I guess we can end discussion, but I don't think we want to today. In my mind it does not.

Okay, expanding the geographical area, no, that has not done.

Expanding the geological area, which, in my mind, either vertical -- Are you proposing to do that? Is the unit being expanded vertically?

A. Not outside of the bounds of the unitized interval.

Q. Okay.

A. We intend to --

Q. So we're not increasing the size of the unit, nor are we increasing the -- either vertically or horizontally?

A. That's correct, we're not increasing the size of the unitized area or the unitized interval.

We are increasing the size of the geologic area that is being --

MR. STOVALL: Area --

THE WITNESS: -- CO_2-flooded.

MR. STOVALL: Excuse me, I'm sorry for interrupting. Sorry, Steve.

THE WITNESS: That's okay.

MR. STOVALL: Area is -- I wonder if maybe that term ought to be "volume" rather than "area". Would that make sense?

THE WITNESS: That would make sense.

MR. STOVALL: And again, I make that statement only so that we know -- we understand what each other is saying, not to say that that is what the rule requires. I think it's interpretive stuff here as far as --

THE WITNESS: Uh-huh.

MR. STOVALL: -- whatever the rule means.

Q. (By Examiner Stogner) I'm really trying when I look at four, the expansion or expansion use, makes a significant change or modification, and I'm limited to the technology or process used for the displacement of crude oil.

You've already got authorization for CO_2 injection, and that is not being changed. Or is there something I'm missing? Is the procedure being changed? You're still injecting CO_2; is that correct?

A. That's correct.

Q. Okay.

A. But --

Q. And that same technology is for the displacement of crude oil. That's not changed; is that correct? From what you've got prior to the -- What's the magic date?

MR. STOVALL: March 6th was it, Tom?

MR. KELLAHIN: March 6th of 1992.

THE WITNESS: Yeah. As I read this rule with my limited understanding, it never mentions unitized areas, unitized intervals or approved project areas.

And from my context, my explanation was, it talks about geologic areas. It doesn't define that it has to be inside or outside. And it clearly shows the intent on number B, the applicability --

MR. STOVALL: Excuse me, Mr. Examiner, I'm going to make a recommendation here.

EXAMINER STOGNER: Okay.

MR. STOVALL: I think the witness is at this point getting into some legal arguments. My -- And I understand why, that's not a criticism.

I think what we need to do at this point is discuss the technical aspects of it.

There are a couple of things that can happen. One is, you may choose to do this with or without approval of the tax credit, and you need the approval in some way to make the conversions into additional injectors. I'm not sure you need the approval for the infills.

You know, and then the question becomes, under what authority do you get that? Do you get it under the existing authority for the East Vacuum unit, East Vacuum project, or does that authority have to be granted by this Order, subject to getting the C-108s approved?

Then the second part of it is a technical evaluation of whether or not there's a criterion necessary to meet the EOR rules.

And then there's the legal argument which intertwines with that and becomes very difficult.

I think the witness needs to talk about the technical things about why the project should be approved at all, just from a conservation standpoint --

THE WITNESS: Okay, I understand.

MR. STOVALL: -- and what the technical aspects of it are, and -- I mean, looking at it as a nontechnician, I think you've explained it, and I have some questions that I would like to have answered on just on that technical side of it.

I think that there are some legal questions that I'm not sure -- I think what happens is that we get into an argumentative phase at this point, and I think we need to -- I'm not sure those issues --

EXAMINER STOGNER: Well, Mr. Stovall, in looking at the Application for Case 10,779, it's asking that five portions be included for recovery of the -- be included or be qualified for the recovery of the oil tax credit. Nowhere does it say a waterflood expansion or a pressure-maintenance expansion or inclusive of new injection applications. I don't even see a C-108, so that's a moot issue.

MR. STOVALL: Well, that was why I raised the discussion at the beginning of the case.

MR. KELLAHIN: Well, that was the discussion an hour ago.

MR. STOVALL: Yeah, that was the discussion I was asking at the beginning.

And my answer to it is, if they can do this under the authority of the existing Order, then it probably doesn't qualify timewise.

If they need this new authority to do it, then we've got -- should that authority be granted subject to the filing of a C-108 -- I don't disagree with you, Mr. Examiner. I think that's the entire issue, or that is a very significant part of the entire issue: Is this a pre-approved project, or is this something that requires a new approval from the Division? And it really is rather convoluted to me.

MR. KELLAHIN: Well --

MR. STOVALL: Well, what I'm -- Before you say anything, Tom, what I'm trying to suggest is that this witness -- asking this witness for his opinion with respect to an interpretation of the rule is probably outside his scope of expertise, and I think that's not fair to the witness. Mr. Kellahin can make those legal arguments with you.

I don't disagree that they exist; I just don't think he's the person to make those legal arguments.

MR. KELLAHIN: Well, and I didn't understand his comments to be in terms of legal opinions. I think they're helpful because we have struggled for months with how to understand particularly paragraph 4.

It is difficult for lawyers and engineers and lay people to understand what this means, and I had appreciated Mr. Stevens telling us how he read it so that when we hear how he's using these words, we understand what he's thinking.

MR. STOVALL: I agree with that part.

MR. KELLAHIN: And there's a -- I don't know how you fix this.

Mr. Catanach's answer was, take it to the Commission and get better clarification of the ambiguities of what in the world we're doing, but...

Not to belabor the discussion, my understanding was, you could take an existing unit, an existing project, and within the geographic boundary and within the vertical limits, could make a significant change in process or technology or somehow expand the geologic area, the volume, the geologic volume in the reservoir that was being swept.

And either one of those, then, would allow you to receive credit on the severance tax, even though you hadn't changed the geographic boundary, you had not changed the vertical limits, and you were still within an approved project.

And so we have sought to cut directly to that issue today by filing an Application for approval of these five project areas for the EOR credit.

If you agree with us, then the rest of the paperwork can catch up with it.

But there's no reason for filing C-108s and all the rest of that stuff unless we meet this one head on.

Now, if you deny it, he certainly has options to go ahead and try to get his injection wells approved in some alternative fashion,

What we're trying to avoid is the confusion we had with the OXY case where they went ahead and filed and obtained administrative approval for additional injection wells, and that was perceived as a possible impediment to the granting of the EOR order.

EXAMINER STOGNER: Let me see if I get this. Mr. Kellahin, correct me if I'm wrong here. Would the only way you would proceed in requesting these expansions -- I'm sorry. See, I'm using the word "expansion" the way I'm used to using the word "expansion".

MR. KELLAHIN: I know.

EXAMINER STOGNER: There's two ways to expand a waterflood unit, let's say, or a waterflood: You have waterflood expansion, which is including new injectors in an existing activity area, or you can expand the area to include additional areas.

So when I use the word "expansion", I'm using it the way I usually do it here.

So in what Phillips is proposing to do, unless you get a tax credit, then, they would not even attempt to go file a C-108 for these injectors; is that correct?

MR. KELLAHIN: No.

EXAMINER STOGNER: No.

MR. KELLAHIN: I've confused you.

EXAMINER STOGNER: Okay.

MR. KELLAHIN: The enhanced credit is not predicated on the financial success of the expansion, the change. It's an incentive.

And Mr. Stevens' testimony, if you put the question to him, will be that this project is financially successful if they add the new injectors.

What it does, is -- the conversation we had with OXY -- is that this is an incentive to allow this project internally within Phillips to get a higher priority, and therefore when they spend dollars on this kind of activity, they're going to spend them here in New Mexico rather than Texas or somewhere else. So that's the incentive for doing the project.

If you deny him the tax credit because you don't think it works here, he still has the option to say, All right, we can live without the credit; I'll go fight for the dollars without the incentive, and if I get approval for my project, sure, we're going to come file the C-108s and see if we can't get the additional injection done.

So this is not an economic decision in terms of whether the project gets done or not. It decides in what priority to get to it.

Does that help?

EXAMINER STOGNER: Yeah, it does, actually.

MR. STOVALL: Let me back -- inject one part of this thing now, is, conceivably from this case there could be issued an order which would say these five projects are approved subject to the approval of the C-108, and you may commence the injection or the reconfiguration of the project areas, but they do not qualify for the tax credit for -- blank reason.

MR. KELLAHIN: That's an option.

MR. STOVALL: I mean, there could be a thing where you do get approval to do the project from this case, but not a certification as an expansion as defined in the EOR credit -- in the EOR Act, excuse me.

MR. KELLAHIN: I agree, that's an option.

MR. STOVALL: So that's where I'm saying we would bifurcate it. There's not a clear line between them; they fall together.

There's also an argument that could be made -- and it's the one that you referred to in OXY -- that what they are asking to do they already have the authority to do by filing -- All they would have to do is file the C-108, and they've got that authority under the old --

MR. KELLAHIN: Well, and that's for us all to struggle with as whether or not that knocks out this project and others like it from the tax credit, and we've struggled with that for almost a year.

MR. STOVALL: Well, we really haven't, because the only two that address that issue are OXY and this one, and neither one has been -- There has been no order issued.

The only other case involved is the one you gave us, and that involved the conversion of existing wells from production to injection, and so there was no additional approval required, no significant additional approval required. Or it's a different type of approval, I guess.

MR. KELLAHIN: And as a footnote, remember Marathon already spent the money before the tax credit had ever been adopted. There are a number of little differences.

But, you know, we're not trying to argue with you. We're all here trying to come to some consensus about what in the world this language means, and I thought it was helpful -- I didn't mean for Mr. Stevens to get into a lawyer discussion.

I was only hopeful that he would give us a point of reference from his background in this reservoir as to why he was contending that there was a significant change.

And the questions put to him are good questions, and we ought to go forward and see how some of those answers are handled.

MR. STOVALL: Well, I'd like to take a different approach, if you don't mind, Mr. Examiner, and go to some specific exhibits that I've got some questions about.

EXAMINER STOGNER: Why don't we do that, and perhaps --

MR. STOVALL: And my ignorant questions will lead to some more technical questions from you.

EXAMINER STOGNER: Sure. And perhaps I need to apologize for that.

I think I got us off on that, and perhaps as we wind down today's case a brief might be in order, since this is the way now, I see, that we're proceeding with this.

MR. KELLAHIN: One of the things we have -- Mr. Stevens and I have worked on is a draft order for you.

We didn't get it tuned enough to present and discuss today, but we're already working on one and we're happy to try to wrestle with some of these questions that are bothering all of us.

MR. STOVALL: I think there's legitimate questions that -- I don't criticize you and Mr. Stevens for advocating a position.

I think, let's look at some --

EXAMINER STOGNER: Okay, why don't I turn it over to you at this time, Mr. Stovall, for some --

MR. STOVALL: Okay. Let me get started and then I'll see...

EXAMINATION

BY MR. STOVALL:

Q. I'm looking at your Exhibits 11 through -- and I'll just deal with project area number one to start with.

Project -- Your number 11, your first of the three packets, just says -- Off the record for a second, Steve.

(Off the record)

Q. (By Mr. Stovall) -- just shows the proposed well patterns and how the pattern will look within the project area, correct?

A. That's correct.

Q. Number two, the second part of the three-exhibit package for each well, the one that's apparently number 12, that is, if I heard you correctly, described as a model of what you would predict as the change in effectiveness of flow, of contact by which you as an engineer justify that there will be additional geologic area contacted, and therefore it is an expansion in that sense; is that correct?

A. That's correct, it's a very simple, simple model.

Q. And my basic question -- and I -- I'm going to ask it, and if the Examiner -- I missed the initial part of it when you first started talking about the first one.

But my question -- as a non-engineer is, how do we have any -- how do we establish any faith in the model as a prediction of what will happen?

A. With any reservoir model you have to start with basic reservoir calculations, basic reservoir understanding, and prove that it works under that situation. You know, that's how all the engineering techniques using reservoir engineering were developed, from simple reservoirs.

From there, they're expounded on as you complicate it.

But as you complicate any model, it can get further and further from the truth. We were not representing that this model here is what's going to happen in reality.

What it does is, it portrays basic reservoir engineering principles when you change an injection well or producing well, how the flow changes in a pattern, in an ideal situation, and we're the first to admit that our reservoir is baffled and complex.

We cannot model that baffled and complex reservoir. We can only model the most simple things and then take ideas from it. We can't use this in a quantitative matter; we can only use it qualitatively. And we see how it matches our actual production data.

Q. Now, let me ask you -- make sure I understand this, again, as a non-engineer looking at this thing.

The various lines, both the orange and the black, are flow lines of the injection fluids as they move through the reservoir and contact the reservoir and hopefully push oil towards the production wells; is that correct?

A. That's correct.

Q. And the black lines are the lines as you have determined that the fluids that are currently being injected in the area are flowing through the reservoir; is that correct?

A. That's correct.

Q. Is there any method -- and if there is, have you used it? -- by which you can contest that initial premise to find out if those flows are, in fact, going in those directions?

A. Well, I guess the most basic test would be to look at the results and see if they match your production data.

When we run these models, we put in actual production rates from the injection wells, which we know. We put actual injection rates from the injection wells in there.

Q. Uh-huh.

A. So we run that and we see, Well, are we getting CO_2 recovery in this well? because the pattern shows there's no stream lines going to it.

And I have done that, and it has given us confidence that the basic model in general represents flow patterns in the reservoir.

Q. Okay. So are you satisfied as an engineer that those black lines do in fact represent what is currently happening?

A. Yes, I am.

Q. On a gross, simplified scale?

A. On a gross -- That's correct.

Remember, we did use actual rates in this, you know. We didn't put idealized rates, except for the new producers, you know. I put what I expected that new producer would draw down, and I believe for that particular well I think I used 500 barrels of total fluid. So consequently it draws a lot of the injectant away from the well we're converting, which is this 0129.

Q. Okay.

A. It's a simple -- And for example, Mr.

Stovall, if you look in this pattern, it doesn't show any red lines going to well 2408, okay? 2408 is in the project area. We believe that well will get a benefit from converting 0129 to injection, because it is immediately offset to that injection well.

Now, this model tells us a lot of things. It tells me that I need to go out and do a frac job in well 2408 and increase the drawdown and draw stream lines up there.

We have looked at these models and we believe that they represent our production very well. And aside to this issue of our hearing today, we plan to use it to make operational changes in our wells.

But it's not to say that -- Even though this simple model shows no flow lines going to 2408, I believe that well will get an incremental recovery. But it will be up to me to come back at that positive production response time and prove that to you before any credit is given for that well.

We don't necessarily believe that this list of wells we're giving you today is the final list, that every well we give you will have a positive production response. They have a good chance, every one of them will have a good chance of getting a positive production response, but we can't guarantee it until we see the production data.

That's the good part in the rule, in that it's -- you have to come back and show your positive production response. And if that well doesn't qualify then, well, so be it.

Q. Okay, I think I -- But I guess I'm going to -- I mean, it's a little bit repetitive, but I'm going to ask you once again.

With respect to each of those modeled analyses that you've done, you're saying that you did start -- Where there is known data to input into the model, you used actual data?

A. Right, actual data.

Q. Where you had to --

A. Where these pro- --

Q. -- the estimates you used --

A. Rates similar to offset producers, representative rates.

And we didn't tinker with it, we didn't use any artistic detail in the model. We ran it consistently in every project pattern, we put to our best of our ability current rates and the injection rates and the producing rates where, the best of my ability, what that well will make when we drill it.

Q. Are there any of those parameters which had to be estimated or -- that might have been adjusted and run the model again to see if there was a different effect? For example, if there was a different production from -- The 2407 is a different 2407 is a new producer; is that correct?

A. It will be. We haven't drilled it yet.

Q. Right, that's what I was thinking, as far as --

A. I haven't done sensitivity cases.

Q. Okay.

A. I didn't run multiple runs with different rates to see where they would come out. I used my forecast rate, and I put it in there and ran it.

Q. So you don't know what a different rate might do in terms of a --

A. No.

Q. Okay.

A. You know, this model has that option. That's how we use it in an operational sense. We can change injection rates with the model and see how it affects the wells.

And that's why also, to make it have more integrity, we included injection rates and production rates, not only from those wells in the project area, but another ring around the wells, so that that effect would be modeled also. That's important.

Q. Is not one of the benefits of modeling the ability to change some rates, to run those sensitivity analyses --

A. Yes --

Q. -- to see what they --

A. -- it is. But I certainly didn't think it was proper at this point to run multiple sensitivities to see -- see what the best sweep we could get with it.

Q. Well, I'm not -- Yeah, I'm not sure -- That would be more of an operational decision.

A. Correct.

Q. But in your professional opinion, do you believe that any change in those parameters, any -- would change the fundamental patterns that you're showing here?

A. Definitely any change in rates, injection rates, will change this model. That's the most significant data input into the model, is injection rates and production rates. That's the basis that it calculates the stream function off of. And those have more -- have the most impact of any data.

Q. Well, considering that, then, do you have an opinion, based upon your experience with the model and your knowledge of engineering, as to whether or not different rates might result in greater or less expanded geologic area contact? Would it be significant towards that issue we're concerned with today?

A. No, I don't believe so. It may make minute changes, but the geologic area that would be swept should be the very similar geologic area.

Q. That's what I'm concerned about. It's not the --

A. Right.

Q. -- not the minutiae about the --

A. -- cosmetics.

Q. -- volumes, but rather whether or not you are in fact gaining additional volumetric contact with the geologic formation.

A. And when I looked at all this, I was keying on geologic area. That was my key when I went into this. Are we contacting a new geologic area? And that was the basis of my analysis.

Q. I think that kind of ends my dumb questions about the engineering side of it.

I do have some more questions that go a little more administratively.

If you have any question, Mr. Examiner, I would say pick it up from where I left off, get more sophisticated with it.

FURTHER EXAMINATION

BY EXAMINER STOGNER:

Q. Well, I don't know if I'll get more sophisticated.

But let's go back to Number 11 and --

A. Okay.

Q. -- the conversion on those. Would they still be water, CO_2. I don't want to call it huff and puff, but --

A. WAG.

Q. WAG.

A. WAG, that's the correct --

Q. Would the same pressures -- and when I say same pressures, those that are similar --

A. Injection rates and pressures of offset injectors?

Q. Yes.

A. Yes.

Q. With no significant change in the completion technique? I mean, would they be completed in the same manner as your offset injector?

A. Yes. It's important to complete them in the same zones and sweep the same zones, especially in the offset producers.

It's more important to match the zones in the producers and injectors, rather than injector to injector, because you're specifically sweeping from injector to producer.

Q. And any project, and this is nothing -- I want to watch my wording here, because you have gained knowledge with each new well, and -- which is on line, or is drilled --

A. Correct.

Q. -- for that matter.

And even if a marl well is drilled in that area, you would still gain some knowledge off the log?

A. That's correct.

Q. But in each new conversion -- and since this is an old pool it brings up some unique situations where you have open-hole intervals that were natural-frac'd years ago --

A. Uh-huh.

Q. -- but are you looking at your injection interval inasmuch as trying to do some micromanagement, as opposed to -- like opening up just certain areas for injection?

A. With the conversions that we're going to do -- Those are older wells. I think two or three of them are open-hole. We plan to run liners in so that we can control the injection and better -- better.

With the injection wells, we don't plan a lot of micromanagement. We will perforate those wells in the same layers that are productive in the producing wells, even if there's not a lot of porosity in them, because we know that it can change from that injector to that producer.

There can be producers at the same stratigraphic unit that produce a lot of oil over here; the injector may not show a lot of pay in its log.

But we know someplace in between there, there's a transition. We're going to try to get CO_2 into it as best as we can.

So the perforations in the injector will as closely as possible match the perforations in the producer.

Q. So this particular project is way beyond micromanagement because of its -- the way it was produced from the beginning, in the technology of the day, Twenties, Thirties and Forties, natural frac as opposed to -- if it was a whole new area today, you'd be more specific in what you --

A. Yes, we don't -- We have a few shot holes, but not very many in this reservoir. We're fairly lucky for old San Andres wells.

But in injection wells, you know, just for a little technical point, injection wells in any and every CO_2 flood rapidly lose their casing. So you lose zonal isolation in your injection wells. Every CO_2 flood is like that.

You only have absolute control over your injectant in the injection wells the first five years. After that, your casing is eaten away by the combination of CO_2 and water, forming a carbonic acetyl.

Q. In looking at Exhibits 5 and 6, that's what brought me to that particular analogy, was your 3-D perspective where you're trying to tell me this was opening op some new intervals or some new lenses that had not previously been opened before.

A. Yes, the plan view shows it almost as well as the 3-D view, that...

These red areas are analogous to the red peaks on -- But what you may not be able to tell is the deep valley between those two sets of peaks. There's a pay interval there, there's a non-pay interval there or an interval with very low pay.

We consider that low pay also low fluid movement characteristics. If it has low porosity, it's going to have low perm. Those two go hand in hand.

So where before we manage this project area from a more macro standpoint, we would manage a whole project area, now we have to look individually, because we have holes in our reservoir. We have to manage it on a pattern basis, which in our instance is what we call microscopic now, is on a pattern basis.

And if we -- You know, if we drill in one of these holes we'll get an uneconomic well, there's no doubt. There's no pay there.

Dolomite can be -- is laid down as a carbonate reef, it's laid down very uniformly. But the porosity is formed afterwards. It's a diagenetic process; it's a secondary process where the rock is dissolved away.

And that diagenetic process lends itself to having cemented areas and uncemented areas, cemented areas meaning no porosity, the pore spaces are filled with some kind of calcite cement.

Q. So your proposed infill wells would be associated with the peaks of this --

A. Correct.

Q. And how would those be completed? Would those be micromanaged or --

A. Those may be micromanaged, in the standpoint that if we -- when we look at our saturations on our logs and we see a zone there with high porosity but may have low oil saturation or maybe a high gas concentration, we will probably not perforate that zone.

Because we can sweep from wells to wells -- Maybe on one particular layer out of 12, might sweep from well to well, but not all the layers will sweep.

So we realize the possibility, when we drill our infill wells, we may have one or two little intervals in there that may have had a little bit of CO_2 through them, and we plan on not perforating them.

As a whole, our 1988 wells showed us that there was very little CO_2 contact with the wells.

Q. The analogy that you're bringing forth today -- and this is absent the incentive price or whatever that we're doing here today -- but have you utilized or has Phillips utilized this same thinking that you're presenting today on, say, one of the previous -- in some of the newer injector wells, not in issue today, that is within this project area, i.e., going even into the -- your 3-D seismic or what you're proposing today, how does that look in practice, in some of the other injector --

A. Well, we definitely have the potential for infill drilling a large portion of the reservoir, based on the 1988 wells, because we realize there's large portions of the reservoir we're not contacting with CO_2.

For us to contact that and get that oil out, we will have to infill drill it.

And this particular area of the reservoir, I'd say, colored by the green, will be our primary area of investigation. We're drilling the reds now, we're drilling the easy ones, the ones that have higher pay and a much higher recovery.

At some -- But we do not know where an uneconomic well will fall yet. We don't have enough data.

So in all probability, there will be some additional infill drilling, but only if these wells we're going to drill this fall pan out. This will give us the courage to take one more step.

Q. A lot of information to digest. But I must apologize to you; this is a new concept that we're taking, that Mr. Kellahin has presented, perhaps a stairstepping type of -- I'm used to usually an all or none, and Mr. Kellahin knows that, so I must apologize to you for the way I worded my questions earlier.

A. As long as you understand as far as my technical presentation today, all my testimony has been directed at increasing a geologic area from the standpoint it's not under CO_2 flood now, because there's no recovery coming from it, and it's not being swept by CO_2 now because there's not a well in that area to draw it down.

And from that aspect of what a geologic area is, we are definitely, without a question, expanding our project.

FURTHER EXAMINATION

BY MR. STOVALL:

Q. Question on -- This is a little more academic. Then I've got a couple of other questions outside the technical.

Have you ever -- Are you familiar with the microseismicity? Do you know what that is?

A. Microseismic techniques?

Q. Yes.

A. I was involved in a Gas Research Institute project in the Canyon sands in south Texas where we ran a microseismic type of logging tool and used it to tell us fracture orientation from fractures closing.

Q. Well, this would be a little bit different, a project which Los Alamos Laboratory has conducted in conjunction with another operator in terms of monitoring microseismic events, downhole monitoring of microseismic events to determine flow patterns. Is that the same thing?

A. I think we're talking about a similar thing.

Q. Okay.

A. It was a tool that -- In our particular project we were monitoring the microseismic events that occur when a fracture closes right after a frac job, the tiny, tiny little changes in the reservoir, as the frac job closes. It's probably a similar tool.

You can use it to determine fluid flow, I believe, also.

Q. It might be interesting, then, if you could ever figure out how to get into it, to see if your model is making good predictions, you can --

A. Uh-huh.

Q. -- actually go down and measure and determine if your model is actually finding out what downhole testing would find.

Something to think about. You can contact Los Alamos if you're...

A. Uh-huh.

Q. A couple questions I've got just real quick on the areas. I think we've got some problems here in terms of area definitions with area three, area four and area five, because they are -- they contain -- have no lines, and the bottom line is to develop a computer system that's going to define areas in terms of a table with squares in it. And it's going to be real tough.

A. We debated that ourselves. There's no guideline in here about how to define a geologic area.

Q. Well, where it really makes a difference -- It doesn't matter to us from that standpoint, because we don't deal with anybody's money.

But to the tax situation and revenue people who, should you qualify for the credit, have to provide that, they have to have an area they can identify. And quite frankly, it's going to have to be an area that they can identify on the computer. And even if it weren't, I think that I -- I don't know what the tax is on the unit. It may be uniform enough.

But if they've got any changes at all, this may cause them some difficulties. And before we submit this project, in order to approve it, as you look at the order, consider an alternative to square off those areas, preferably in quarter sections -- quarter quarter sections.

A. Well, may I make one comment?

Q. Yeah.

A. Not knowing anything about your tax and revenue, most taxes are based on production of individual wells, not off of geologic areas or geographic areas.

And in this case I think definitely the list of producing wells will control how taxation and revenue gives it out. I don't know how they define their areas or if they have a computer model of every lease.

But in our mind -- This blue line, personally, did not mean a lot to me. The most important thing was that list of wells that we expected to get a response from.

And we debated whether to give a quarter-quarter section description. But if we were to contain that to just the wells, they were going to take about three-quarters of a page or a page for their own project area, because we're cutting tens in half and --

MR. STOVALL: Well, I think you can give that consideration, look at it. I mean, it may be -- I understand what you're saying, and -- Practically, you're probably right. This is state government, after all.

MR. KELLAHIN: And I think that's perhaps a clerical thing that we could work our way into.

What I asked him finally to do was give me an area, however shaped, that he was comfortable with, showed an area that was going to be affected by the injection, and that's where we -- how we got here.

Q. (By Mr. Stovall) I understand that, and I don't...

Also normally when we're talking EOR, jumping through the hoops, but from your answer here I think you are aware of the process that is involved getting this approval, assuming it's done, getting the positive production response, meeting those time frames and all that. So I don't believe there's a necessity to do that.

The only question I would ask is, assuming -- If it were approved, was this something you would commence immediately, or would you have -- need some time to do the drilling and pipeline construction, other facility construction?

A. Well, maybe you can help me out here also.

When we look at this rule, all it says is, approval before injection starts.

Q. Well, let me tell you what we do. What we do is, we issue a certificate that it qualifies, and your time frame for getting a positive production response is measured from the date of that certificate.

A. Yes.

Q. Given the fact that you've still got to file

C-108s, given the fact you've got to drill some wells and presumably lay some lines to get to your new injectors, the conversions, if it were to take you a year to get to the point where you could start this project, you would have wasted a year if we issue a certificate today, or upon the issuance of the order.

A. We -- I understand, I see where you're coming from. We will do all this work this year, definitely.

Q. So you're not concerned -- I mean, if we issue a certificate effective the date of the order, you're not concerned about the lost time to get that production response?

A. The only thing I'm concerned about with the certification, the order, is how it connects with the drilling of the infill wells.

Originally, we were planning to hold off drilling the infill wells until we had certification. We certainly didn't want to put anyone in a bind, certifying a project that was already in progress.

But there's a fine point here as to whether injection starts where the infill wells are drilled.

If it's possible to get any kind of understanding today out of you and Mr. Stogner as to whether we have the ability to start wells next month, even if the order is not given, as long as we don't convert the injection wells.

Q. Well, let me -- I think what would happen in that case is, if the Order is issued approving the project, you could drill your wells knowing that you will get a certification, and then you come back to us and say, We are ready to start injection, certify the project. And give us a date.

And that's going to be the key; it's not the order itself. It's the date of the -- You actually get a piece of paper that says your project is certified effective such and such a date.

A. Oh, you mean the positive production response certification or the initial certification?

MR. STOVALL: Are you with me on this?

MR. KELLAHIN: No, I think we're talking two separate things here.

MR. STOVALL: Your positive production has got to occur within, in this case -- I assume we're calling this a tertiary project?

THE WITNESS: Yeah, seven years.

MR. STOVALL: It's got to occur within seven years of the date that we certify to you that this project qualifies.

The day we issue an order saying, Yes, this project can qualify, is not necessarily the date that we certify. We can issue you an order that says --

THE WITNESS: I understand.

MR. STOVALL: -- this project qualifies and you are authorized to proceed.

THE WITNESS: Right.

MR. STOVALL: You begin your construction, you do everything. But you don't turn on a single injector until -- When you're ready to turn on the injector you come back to us and say, Okay, we're ready to begin injection; give us a certification for the project.

And that's the date that you're going to measure from.

THE WITNESS: That's fine. I understand that.

MR. KELLAHIN: What he's asking is, does he jeopardize his EOR certification if before you issue the order in this case he has somebody out in the field go start drilling an infill well, producing infill well.

And that's the question we had with OXY the other day, is --

MR. STOVALL: I don't think a producing well does that.

MR. KELLAHIN: That's my opinion, and I think we've agreed that if he goes and starts a producer tomorrow, that is not a fatal flaw. He hasn't shot himself in the foot in getting his certification.

MR. STOVALL: I think that's correct. You could do that without this order, and drilling a producer doesn't qualify you for the project.

THE WITNESS: Right.

MR. KELLAHIN: What he needs to keep from doing is putting water in the ground in the injector well --

MR. STOVALL: Correct.

MR. KELLAHIN: -- because that will bust his eligibility.

MR. STOVALL: Exactly.

THE WITNESS: But that's very important to us, because we have to do this work; our management told us we have to do this work this year.

MR. STOVALL: I understand.

THE WITNESS: And we're ready. We have drilling permits already received, but we are holding off on the work.

MR. STOVALL: The drilling is not the critical issue; it's the injection, is going to be the -- Make sure you get the certification from us before you do the injection.

THE WITNESS: Okay, that's fine. That will make a lot of people happy at Phillips Petroleum.

MR. STOVALL: And I don't -- I think that's -- That's all I've got on this one, I think.

And you can feel free to ask questions on that. I mean, that part we can clean up.

EXAMINER STOGNER: I'm going to accept your offer for a proposed order.

MR. KELLAHIN: I know from your questions, Mr. Stogner, the areas of concern you have. Mr. Stevens and I will attempt to address those within the context of a draft order, to simply give you the answers from our point of view, and it would be a vehicle for you to resolve this for yourself.

So I think a draft order, rather than trying to develop a memorandum, is more useful to --

MR. STOVALL: We have no authority.

MR. KELLAHIN: You know, there's probably no purpose in a memo. You and the rest of the Division have a clear understanding of what we have to work with, and I think if we give you a proposed order, that's as much as we can help you.

MR. STOVALL: Yeah, I think that's correct, because there's no authority upon which to write a memorandum anyway.

EXAMINER STOGNER: Anything further?

MR. STOVALL: No, let's just visit on that area, because that's affected by the order.

EXAMINER STOGNER: Well, with that, I have no other questions of this witness.

Do you have anything further, Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Mr. Johnson? His silence says no.

With that, this case will be taken under advisement.

MR. KELLAHIN: Thank you for your time.

(Thereupon, these proceedings were concluded at 3:30 p.m.)

* * *

CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation 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 August 31st, 1993.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1994

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 10779, heard by me on 29 July 1993.

_____________, Examiner
Oil Conservation Division