STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

APPLICATION OF PHILLIPS PETROLEUM COMPANY)

CASE NO. 11,014

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

July 7, 1994

JUL 27 1994

Santa Fe, New Mexico

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

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I N D E X

July 7, 1994
Examiner Hearing
CASE NO. 11,014

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E X H I B I T S

	Identified	Admitted
Exhibit 1	8	55
Exhibit 2	19	55
Exhibit 3	9	55
Exhibit 4	20	55
Exhibit 5		55
Exhibit 6	25	55
Exhibit 7	25	55
Exhibit 8	26	55
Exhibit 9	29	55
Exhibit 10	29	55
Exhibit 11	29	55
Exhibit 12	31	55
Exhibit 13	34	55
Exhibit 14	39	55
Exhibit 15	43	55
Exhibit 16	43	55
Exhibit 17	48	55
Exhibit 18	55	55

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A P P E A R A N C E S

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* * *

WHEREUPON, the following proceedings were had at 8:43 a.m.:

EXAMINER CATANACH: At this time we'll call Case 11,014.

MR. CARROLL: Application of Phillips Petroleum Company for a nonstandard oil proration unit, an unorthodox oil well location, a high angle/horizontal directional drilling pilot project, special operating rules therefor, a special project oil allowable and production testing period, Eddy County, New Mexico.

EXAMINER CATANACH: Does that about cover it, Mr. Kellahin?

MR. KELLAHIN: I don't think we missed anything.

EXAMINER CATANACH: Okay, appearances in this case? I'm sorry.

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 CATANACH: Additional appearances in this case?

MS. TRUJILLO: Yes, Mr. Examiner, my name is Tanya Trujillo. I'm an associate with the law firm of Campbell, Carr, Berge and Sheridan.

I am entering an appearance on behalf of Bass

Enterprises Production Company, and I would like to read a statement at the end here.

EXAMINER CATANACH: Okay.

MR. KELLAHIN: I have one witness to be sworn, Mr. Examiner.

EXAMINER CATANACH: Okay, please swear in the witness, Mr. Carroll.

(Thereupon, the witness was sworn.)

MR. KELLAHIN: Mr. Examiner, Mr. Schramko, who is a reservoir engineer with Phillips -- he and I were before the Division last fall, requesting a special depth bracket oil allowable for this Delaware pool. It's identified as the Cabin Lake-Delaware Pool.

I could not find in the *Byram's Handbook* a reference to this change in depth bracket allowable for the pool, so I want to give you the order that we asked the Division to issue which establishes that on 40-acre oil spacing for this Delaware pool, we have 187 barrels of oil a day.

In addition, Mr. Examiner, it will become apparent to you that the location of this well is within the oil-potash area. I'm here to represent to you today that it is our information and belief that the application for a permit to drill this well, which is on a BLM oil and gas lease, has been approved by the BLM, the Carlsbad office, the Roswell office, and will be approved here in Santa Fe when the paperwork is received in Santa Fe. We expect that approval in the next few days.

So the exact location of the surface for this well is one dictated by the requirements of the Bureau of Land Management in managing its potash resources, but we believe we've satisfied all those issues.

We've notified the potash operators. There are only two operators. We have a waiver from one and no objection from the other, so this is not a potash dispute.

In addition, Mr. Schramko will tell you that they propose to case and cement this well pursuant to the rules of R-111-P, so again that is not an issue.

With your permission, we'll call Mr. Ken Schramko.

EXAMINER CATANACH: Please do.

KEN SCHRAMKO,

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. Schramko, for the record would you please state your name and occupation?

A. Yes, my name is Ken Schramko. I'm a senior reservoir engineer with Phillips Petroleum in Odessa, Texas.

Q. On prior occasions, Mr. Schramko, have you testified before the Oil Conservation Division as an expert witness qualified in the field of petroleum engineering?

A. Yes, I have, twice, in October and December of 1993.

Q. Have you in your capacity as a reservoir engineer made an engineering study with regards to the details concerning this proposed Application by you and your company?

A. Yes, I have.

Q. One of the components of this request is the utilization of what is referred as rate-time analysis?

A. That is correct.

Q. Are you recognized within your company as an expert in the engineering aspects of rate-time analysis?

A. Yes, I am.

Q. How did you obtain that expertise?

A. Generally accepted within the industry, Phillips Petroleum had an employee, Mike Fetkovitch, who's regarded as one of the industry experts in rate-time analysis. I was fortunate enough to work for him for four years, and during that time I did most of the rate-time analysis problems that came to Phillips in the corporate office.

Q. Have Phillips employees relied upon you, other engineers, to aid them and to analyze the performance of wells using rate-time analysis procedures?

A. Yes, that is correct.

Q. And is that a component of this particular Application?

A. Yes.

MR. KELLAHIN: At this time, Mr. Examiner, we tender Mr. Ken Schramko as an expert reservoir engineer with special expertise in rate-time analysis.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Mr. Schramko, let's take what we've marked as Exhibit Number 1. Would you identify that display for us?

A. Yes, Exhibit 1 is a land map of the Cabin Lake-Delaware Pool. The pool is located in Townships 21 and 22 South, Range 30 East, Eddy County, New Mexico.

On this exhibit the yellow-highlighted area represents the Phillips Petroleum-operated acreage, which represents approximately greater than 95 percent of the total production in the field.

Also shown on here are the pool boundaries, outlined in red. And if you'll direct your eyes to the southern half of Section 11, you'll see where the proposed well has been schematically shown in drill locations N, O and P.

Q. When we look at the display, can you identify for us what wells that currently produce from the Cabin Lake Pool that Phillips does not operate?

A. Yes, straight to the east in Section 12, straight east of the horizontal well, is a Bass Enterprises well, James Ranch Unit 48 Number 1.

In the southwestern corner of Section 36, Corrine Grace operates the Salomon Number 1.

In Section 34, in the top left of the diagram, is the Yates Julia AJL Federal Number 4.

Just south of that, in Section 3, Heyco has a well, the Donnell 3 Federal Number 1.

Q. Describe for us the significance of the green line that's captioned "Potash Line".

A. Okay, that's on Exhibit 3.

Q. Then we've mismarked the exhibits, because those that we have passed out has the green line. Okay?

A. Okay. Is that what yours has too?

MR. KELLAHIN: Yes, sir, I think so.

Mr. Examiner, does your display show a potash line?

EXAMINER CATANACH: It does.

Q. (By Mr. Kellahin) All right, let's deal with that one, Mr. Schramko.

A. All right, they're essentially identical exhibits, so it's of no consequence.

The green line represents the -- our best approximation of where the potash line sits as it goes across the field.

Of pertinence to this well, in the southern half -- or southern portion of Section 11, south of that green line would represent where the measured potash reserves are located.

And you'll also notice that there is no orthodox location that can be placed in drill locations N, O and P, so we were obligated to use that northeastern wedge in location P for the surface location of this well.

Q. Identify for us the offset operators, the display captions, James Ranch Unit. What is that intended to mean?

A. That would be -- That is operated by Bass Enterprises.

Q. Are there any other --

A. There are no --

Q. -- offsetting enterprises to the project area, other than the Bass-operated James Ranch Unit?

A. That would be correct. The only existing well that offsets this at the present time is the Bass Enterprises well. There are none to the south.

Q. All right, sir, let's use this schematic and talk about the project. What do you propose for the project unit area?

A. For the project unit area, we are asking to establish a 120-acre proration unit comprised of locations N, O and P.

Q. With regards to the drilling producing window within that nonstandard proration unit, what are you recommending?

A. That we honor the 330 setbacks that exist for 40-acre vertical wells. No change there.

Q. Depth bracket oil allowable for the pool is what, sir?

A. For vertical wells, they're spaced on 40 acres and the allowable is 187 barrels a day.

Q. What is your proposal for the depth bracket allowable to be assigned to the nonstandard proration unit for this project well?

A. Well, it's consistent with other applications of this type. We're asking that the allowable be 187 barrels a day, times the number of drilling units contacted -- in this case, three -- and that would equate to an allowable of 561 barrels per day.

Q. The Application also asks for a special testing period?

A. Yes, it does.

Q. Summarize that request for us.

A. Basically we are asking for a one-year period, starting from the first day of production, that the well be allowed to produce at capacity rates, with several limitations on the daily production withdrawals.

The first of those would be -- and basically what we've done is carved that one-year period up into two pieces. In the first part of the test period we're asking to be able to produce the well at three times the project allowable, to 1683 barrels a day. And I'll be showing later that that's consistent with what we think the expectations of this well are.

In the second half of this test we would ask that we be allowed to produce the well at one and a half times the project allowable, or 842 barrels a day.

There's another component to the test period, and that is that, of course, if that is granted we would accrue overproduction while doing that, and as a result of that overproduction we would make up all of that overproduction during the second year, such that at the end of 24 months there would be no overproduction on this property.

Q. Are you asking for an increased allowable above the project allowable of 561 barrels of oil a day?

A. No, just for permission to temporarily overproduce the well.

Q. And you're not asking that that overproduction be canceled but, in fact, establishing a procedure by which you would make up the overproduction?

A. That is correct.

Q. Before we discuss the purposes of the test, describe for us how we would make up that overproduction.

A. Okay, at the end of the first year, or as the end of the first year is approaching, we would accumulate the total overproduction and contact the district office and set up a plan so that the overproduction would be made up during the second year, again so that at the end of the second year it would be zero.

Q. Have you already talked to Mr. Sexton, the area district supervisor for this project, and advised him of your proposal?

A. Yes, I did. When we were attempting to describe this special test period, we felt it was wise to speak with him because there is the administrative problem as to how to handle this, and he felt this was a wise way to proceed.

Q. Can you approximate for us the volume of oil that would be overproduced in the first year if the test period is granted?

A. Yes, it would be approximately 147,000 barrels of oil.

Q. Have you studied this reservoir to determine whether or not there is sufficient size and shape to the reservoir to determine the magnitude that 147,000 barrels of oil would represent in relation to the total recoverable oil in this area?

A. Yes. On average, each of the 40-acre tracts has approximately 1 million barrels of oil in place, so in the project area we would have 3 million barrels of oil.

So 150,000 of overproduction would represent 5 percent of the total oil in place, which we would consider to be a relatively small amount of oil.

Q. Do you have an opinion as to whether the granting of this special test period would allow this well to recover oil from offsetting tracts, either drilled or not drilled?

A. I've looked at that, and I would conclude there will be no drainage of offset, basically because we're going to make up the overproduction.

Q. Do you see any opportunity that the approval of the test period would violate correlative rights?

A. No, for the same reasons.

Q. Let's talk about the test. What is the purpose, then, of having the opportunity to overproduce the allowable in the manner you propose for that first year?

A. The objective is so that we can perform rate-time analysis.

Q. Describe for us what that means.

A. Okay. Rate-time analysis is basically the procedure whereby we can plot the production data as it declines over time, do some rigorous type curve matching, if you will, and thereby obtain the permeability and skin of the well.

Q. Do you as a reservoir engineer have any other ways to obtain this kind of information in evaluating the performance of a well?

A. Yes, another standard tool would be the drawdown-buildup test.

Q. Why have you chosen to recommend the rate-time analysis?

A. Well, basically I'll begin by saying we have no intentions of running a drawdown-buildup test, whether or not the test period is granted.

There is the problem you have, basically because this well will be on artificial lift; it will be equipped with a downhole submersible pump. And running the downhole gauges in a well such as that, first it's very difficult to get meaningful data because of this downhole equipment. It's difficult to get the gauges in there and run the test, is what I'm trying to say.

Secondly, there's the element of jeopardizing a well anytime you would run slickline tools in there.

But basically, because of the difficulty of simply obtaining data, we are not going to be running a drawdown-buildup test.

Q. When you have the data that gives you a method to determine permeability and skin effect, how is that relevant to the decisions the Examiner needs to make with regards to vertical versus horizontal wells?

A. Well, basically the horizontal wells are so unique because, in many practices, if we're unsure what the damage might be in a vertical well, we'll acidize it.

In the case of a horizontal well, that's not well advised. You really need to know, before you go in there and acidize, whether or not you need to, basically because you're going to be pushing coiled tubing out into the wellbore, across the horizontal length some 2000 feet to acid-wash this.

And first, you jeopardize the well, just by that operation. The coiled tubing can twist off and you jeopardize it. So you just don't want to be entering wells without knowledge as to whether you need the stimulation or not.

Q. Give us a summary of why you're proposing to apply this horizontal technology in this particular reservoir.

A. Well, we're very fortunate that the cherry Canyon zone that we are targeting is probably in the upper -- I shouldn't say "probably". It is in the upper two percent of what you're going to find in the Delaware.

These zones, as I'll be showing you here in a moment by talking about a typical vertical well, they're making 200,000 and 300,000 barrels from a typical -- from just a 40-foot interval. That's very unique in the Delaware.

And, you know, any horizontal well is going to cost upwards of a $1.5 million to drill, and it's going to take those kinds of reserves to justify a horizontal well.

So we're fortunate that horizontal technology may make sense, and we expect to recover about 600,000 barrels. You're not going to find that everywhere in the Delaware.

Q. Why have you chosen these three spacing units as your project area?

A. Basically it's the remaining undrilled acreage that we have where we can establish reserves.

Q. Let's talk about, in a summary fashion, how you got to your expectation of the upper range for the test period of 1600 barrels of oil a day.

A. You're referring to the reservoir models?

Q. Yes, sir.

A. Okay. Well, basically that's it. We ran -- Or I ran three reservoir models, single-cell tank models, to give us some expectations of what the well might do.

Q. And so when we talk about approximately 1600 barrels of oil a day as the initial starting point for the test period, it's based upon your reservoir simulation, using some modeling?

A. That is correct.

Q. All right. During the test period, if we produce the well up to 1600 barrels of oil a day, do you see any opportunity that that rate of withdrawal would cause any reservoir damage?

A. No.

Q. Why not?

A. Basically I'll be showing that the damage in wells, vertical or horizontal, is generally related to fluid velocity, that being coning, fines migration.

And what I'll be showing you later is that the fluid velocity, even at the rates we're talking about, is far less in a horizontal well than in a vertical well, which would produce at a consequently lower rate. But even so, the fluid velocity is far less in a horizontal well.

Q. Have you examined whether or not the granting of this Application would put Bass at a disadvantage in the reservoir?

A. Yes, I've considered it, and I don't believe it will.

Q. Okay. Let's turn now to Exhibit Number 2. Would you identify that display for us?

A. Yes, Exhibit Number 2 is simply a blow-up of the southern portion of Section 11, where you can see drill locations N, O and P, and in red is shown the path of the horizontal well.

Starting at point A, which is 10 feet from the east line and 1060 feet from the south line -- Now, that is the surface location of the well.

The segment from A to point B represents the curved portion of the well, and B represents where the well would go horizontally and the first point at which we would encounter the pay. That's in an orthodox location, located 636 from the east line and 909 feet from the south line.

Then we would proceed to drill horizontally some 2166 feet to point C. We estimate the bottomhole location to be 400 feet from the south line, 2740 from the east line. Whether or not we actually hit that point would remain to be seen, but we would certainly honor the 330 setbacks and never cross those boundaries.

Q. You're asking for approval to have the operational flexibility to take this producing portion of the lateral and drill it anywhere within that window, provided you honor the 330 setback?

A. That is correct.

Q. Okay. Give us a basis for why it's initially planned to drill in a -- approximately a southwest direction.

A. Well, if you work through the problem as we did, you really didn't come up with many choices.

The first objective is to try to keep the well trajectory straight. So, starting at point A, we wanted a straight line from A to point C, wherever that would be, just to simplify the drilling procedure.

As you can see by looking at point B, B couldn't be very far north and stay within the drilling producing window, which forced putting B at a point at which you honor that, which forced C to be near the southern portion of location N.

So really there was no opportunity to really move the well. If C had come in near the top northern portion of Tract N, then B would have probably been outside the joint producing window.

Q. Let's turn now to Exhibit Number 4 and have you identify and describe the well plan.

A. Okay, this exhibit is simply a sketch of the wellbore trajectory. Everything shown on here is in compliance with Rule R-111-P.

Basically, we would drill the well to 475 feet and set 13 3/8, then drill vertically to 3700 feet, set 9 5/8, cement it to surface.

We would then drill vertically to the kickoff point at 5124, at which point we would rig up the directional equipment and drill the curved portion.

When we reach a horizontal position at a true vertical depth of 5768, we would set 7-inch casing. And from there we would drill a 6-1/8-inch hole, horizontally, some 2166 feet and set a 4-1/2-inch slotted liner, install the submersible pump and put the well on production.

Q. Let's turn to the reservoir itself. Did you bring us a type log in this area that we might have you describe the reservoir?

A. Yes, it's a 2-inch neutron density log of the James E 8. If you refer back to one of your other exhibits you'll see the James E 8 is the nearest offset well. So it is the well we're using to target where we would expect the top of the formation to come in.

And on this log, if you flip through and proceed downward through the log, I've marked on there each of the key points of significance, starting at 3700 feet, I'm showing where the 9 3/8 casing would be set. Just below there shows where the Delaware formation comes in, which is also the top of the Bell Canyon member at 3740.

Flipping a little further, I've shown the Cherry Canyon top at 4510. A little bit further, the kickoff point at 5124.

Flipping down a little further yet, at 5768 feet TVD, that is the location of where the seven-inch casing would be set and also the targeted zone within the Cherry Canyon. Just below that is the Brushy Canyon top at 5904, and at the very bottom of the log is the bottom of the Delaware, top of the Bone Spring at 7425.

Q. This Examiner has seen a number of presentations for the application of horizontal technology in other types of reservoirs. We're most often here with a fractured reservoir where the operator seeks to encounter multiple fractures or he's got a low permeability reservoir of narrow height and he's trying to improve the performance of the well through the application of that technology.

Is this like that, or is this something else?

A. Well, this is certainly not naturally fractured. The nearest standard similarity when you talk about horizontal wells -- But this would be a relatively thin pay zone of good permeability.

Q. Does this represent, to the best of your knowledge, a unique application, if you will, of this technology to a Delaware pool?

A. Yes, very unique in that the reserves are adequate to justify the drilling horizontally to pay out the investment.

I might add, to that end, traditionally in the

Delaware you're going to drill vertically and encounter three zones, maybe four, of approximately 30,000, 40,000, maybe 50,000 barrels each, in each of those zones. So you have to drill it vertically to encounter that and to get the total reserves required to justify the well.

Q. And in that type of Delaware reservoir, if you have a horizontal well then you're going to miss two of the three of the pools -- or portions?

A. Yeah, you -- That's correct, you'd miss two or three of those, you'd drill vert- -- or drill then horizontally through the best one of those, presumably, say, it's a 50,000-barrel zone. And that horizontal well would recover, rule of thumb, three times that, give or take, 150,000. So you haven't gained anything. You've left as many reserves behind as you have gained horizontally.

Q. If this pilot project is successful in the Cabin Lake-Delaware, do you see its potential application to other Delaware pools?

A. Not very many. As I stated, you're going to have to find a zone of significant reserves, and there just aren't many out there.

Q. Because of its unique nature and its position at this reservoir, does it allow you to access spacing units that you could not access with vertical wells because of the potash constraints of the BLM?

A. That is correct, that would be specifically locations N and O.

Q. We feel no other way to access those spacing units in the absence of a horizontal well?

A. Well, I shouldn't say no way. In fact, we could -- if we look at any one of the exhibits that is a land map, we could -- specifically your Exhibit 1, that shows the location of that potash line --

Q. Yes, sir.

A. -- we could in fact locate a drill location near Well 6 in Section 11 and then drill a deviated well -- it would be deviated some 1300 feet -- and drill, then, vertically through location O.

Q. All right, you're talking about a directionally drilled well, if you will, as opposed to a horizontal well?

A. That's correct, but you'd be deviating so far that you're in effect drilling a horizontal well, in a manner of speaking.

Costwise, it would certainly be far more than what we're proposing. And in fact, I should add, it would probably be uneconomic.

Q. Okay. Let's turn to the mapping, the geologic mapping of the reservoir. If you'll identify and describe Exhibit Number 6.

A. Okay, the next two exhibits are geologic maps, just intended to show the reserves and why we believe the reserves are still there.

The first of those, Exhibit 6, is the structure map of the Cherry Canyon member. Basically it's a simple anticline with the top of the structure at approximately minus 2450 feet, and the vast majority of the field runs through the fairway in a north-south direction along the crest of that anticline, and you can see structural decline both to the west and to the east.

Of significance, I suppose, is that the horizontal well -- which is also shown on this exhibit, just south of the James E 8 -- is on that structural top. So we would anticipate to have the same amount of pay as in the other wells just north of it.

Q. All right, sir. Let's turn to the isopach, Exhibit 7.

A. Okay. It basically confirms much of the same thing.

The majority of the field -- The majority of the good wells, anyway, which are those just north of the proposed location, have between 100 and 125 feet of gross sand. And as you can see, the proposed well would encounter similar amounts of gross sand. So we're quite confident the reserves are there.

Q. Perhaps we need to save Exhibit 1 as a locator map to help us identify some of these well names and numbers. If you'll set that aside for a moment, let's now turn to this production plot, which is identified as Exhibit 8.

Before you describe it, let's find the well that corresponds to Exhibit 8.

A. Okay, the James E 8 is located in Section 11, just north of drill location P.

Q. All right. Let's see, this is the James E 11, is it not?

A. Oh, excuse me, excuse me. This is the -- Excuse me, this is the James E 11, which is located in Section 12, in the far northwest quarter of Section 12.

Q. All right. And it's Exhibit 8 as to the James E 11?

All right, sir. What information is plotted on the display for that well?

A. Okay, the purpose of this exhibit is simply to show what this typical behavior is of a vertical well drilled into this Cherry Canyon member.

And what we're showing in black is the production rate in barrels a day. And the black X's are our forecast of production, starting in 1994 and proceeding through 1999.

The red line is the cumulative oil to date, there in the beginning of 19- -- of this year.

And the red X's are the forecasted cum oil versus time as a result of the forecast.

And the basic point of this exhibit is that we would ultimately expect to recover about 200,000 barrels from this well -- and this speaks for the vast majority of the wells -- in this zone, in this Cherry Canyon member.

Q. As part of your preparation here, as well as in the past case you did for the depth bracket allowable, you've examined the production of all these wells?

A. That's correct, and I selected this well simply because the production plot was easiest to see the trend.

Q. Does this represent a typical signature of the production trends for a Cabin Lake-Delaware oil pool?

A. Yes, it does.

Q. The estimation, then, is on average that these wells will ultimately accumulate 200,000 barrels of produced oil?

A. That's correct.

Q. What kind of rates do we see when a typical vertical well comes on line? What kind of initial rates do you see?

A. They will sometimes be as high as 300 barrels a day, quite often 200, but somewhere in the 200 to 300 range.

But then of course we have the allowable bracket of 187, so I'm only talking about an initial test rate.

Q. As we stand now, can you approximate for us how many producing wells are still producing in the pool?

A. It would be approximately -- In this specific interval or -- ?

Q. Yes, sir.

A. About 25.

Q. Of those wells, how many are capable of producing the current depth bracket allowable of 187 barrels a day?

A. There are seven. And I might add, really, when you get into the northern part of this field, this zone takes on a different geologic character; it's of lower-quality reservoir.

So basically when we talk about the 200,000-barrel wells, we are confined to the southern portion of our acreage.

Q. Let me address now the topic of how you got to the conclusion about the 1600-barrels-of-oil-a-day rate so that you could plan your test.

That effort was initially done based upon some reservoir modeling?

A. That's correct. I had three reservoir models that I could use to -- as I say, to get the expectations of the horizontal well.

One of them is an out-of-house model; I'll call it the DEA-44 model. It was an industry concerted effort. Some 33 companies went together and contracted Maurer Engineering to create this model. It was, oh, I don't know, a $5-million project or so.

The other two are Phillips in-house models.

Q. Let's turn now to Exhibit 9 and look at the input parameters that you put into the DEA-44 model.

A. Okay, I won't spend much time on this. It's mainly provided in the event there are questions about the specifics of that model. This would show the input parameters that went into that DEA-44 model.

Q. Let's turn now and have you identify for the record Exhibit Number 10. What does this represent?

A. Exhibit 10 is also just background information, if there are questions regarding a model.

This includes five pages from the DEA-44 manual, and it basically provides background and some of the assumptions that are in the model.

Again, I'll only use this exhibit if there are questions regarding those assumptions.

Q. All right. Let's turn now to Exhibit 11 and have you identify for us the production forecast that you generated after running all three models.

A. Okay, the basic reason I ran three was, as I say, they all have slightly different assumptions, and I wanted to investigate the consistency.

So what we're seeing here are the forecasts from the results of each of these three models, the first being the DEA-44 model.

The second one is our in-house horizontal model.

And the third one is a vertical model. Within Phillips we have shown that a horizontal well can be treated as a vertical well, if you will, with a very large frac job. So we can equate the horizontal well to a frac length and compute the forecast with a vertical model, and I've done that as well.

So we have three forecasts, and at the bottom of this exhibit you can see the ultimate recovery from each, and it -- very consistent results, ranging from 628,000 to 661,000 barrels of oil.

Q. The vertical model has been adjusted so that it can function to give you a forecast of what that application would be for a horizontal well?

A. That's what it's doing. It's in effect treating this well as a reservoir with -- for simplicity, I'll say with a 2166-foot frac length, which we have shown to be equivalent to a horizontal well. It was just another way of looking at the problem.

Q. All right. The conclusions, then, from looking at the results of the model are what, sir?

A. Basically we were getting consistent results and that we have some basis for showing the expectations of this well.

Q. The Division practice is to take the depth bracket allowable for the spacing, times the number of spacing units cut with the horizontal well, in this case three, and that would get you the 561 allowable number.

How does that number compare to what the model predicts for the performance of this horizontal well?

A. Well, if you look at -- still on this Exhibit Number 11 -- the first year -- and of course that's the average annual rate. It will in fact come on at each of these models' predicted rates of between 1500 and 1800 barrels a day in the first month, declining to approximately, oh, 500 to 600 barrels a day in the 12th month, averaging out to these 971-barrel-a-day rates.

And as you can see, that's what -- a good 50 percent higher than what the allowable is.

Q. All right, let's turn now to Exhibit 12 and look at your production forecast comparisons of a horizontal versus the vertical well versus the three vertical wells.

A. The only purpose of this exhibit is, there is a rule of thumb in the industry that suggests that a horizontal well will recover on the order of two and a half to three times a vertical well, and this exhibit is to show that that is consistent with this project.

The first column is the same forecast you saw on the previous exhibit for the DEA-44 results.

The next column is a vertical well, and this forecast came out of each of these models -- well, the DEA-44 model.

And what you can do within these models is -- which is actually the first step -- is to model a vertical well. So you model a vertical well and make sure you're on board there. And as you can see, it will ultimately recover 206,000 barrels.

That is consistent with what I stated a moment ago on the James E 11. So we knew we had a vertical well pegged. We then switch the gears and run the horizontal case, and that's the 628 in the second column of data there.

And then the final column on this exhibit is nothing more than three times the vertical well, and it's to show that three times the vertical well is 619,000 barrels, and that's similar. So the rule of thumb holds.

Q. Let's move into the analysis and the process of what we've characterized as the rate-time analysis. Let's start with the -- addressing the reservoir flow velocity.

A. Okay.

Q. That is one of the activities that you engage in as a reservoir engineer.

Give us the formula and the process, and then we'll go to the specifics.

A. Well, basically, to address damage, I'm going to use fluid velocity because all of the -- I'll say the key elements in reservoir damage are a function of fluid velocity. And again, those are gas coning, water coning, fine migration.

If you can demonstrate that your fluid velocity in a well is significantly higher than in other wells, you would have a component to concerned with damage. If you can show it's far less than the velocity in other wells, you would be demonstrating that your damage component is negligible.

Q. Why is it important for you as a reservoir engineer to be able to quantify whether you're seeing reservoir damage or something else?

A. Are you referring to the fact that we would have to stimulate the well? Is that --

Q. The concept of fluid velocity helps you understand whether or not you have reservoir damage occurring?

A. That's correct.

Q. All right. How does that help you decide whether you're drilling a vertical or horizontal well? Does that make any difference?

A. Well, basically, of course, you're concerned with that initial rate. One of the first questions you have to ask in any well is, how high of a rate is too high?

So if I can show that producing this well at 1600 barrels a day does not concern me from a fluid velocity standpoint, then I'm not concerned about damage.

Q. So whether it's a horizontal or a vertical well, you as a reservoir engineer want to know if you're causing or creating reservoir damage because you're producing the well too fast?

A. That's correct.

Q. All right, and this is a method by which you can analyze and determine if you're causing reservoir damage?

A. That is correct.

Q. All right. Describe for us, then, the calculation by which you apply these specifics in order to reach an engineering conclusion.

A. Really, this exhibit is quite simplistic. It begins with a derivation that says velocity is equal to the flow rate divided by the cross-sectional area. That's a simple physical equation.

The second gridded block down there, I've simply taken the velocity and converted it to a ratio. So I'm defining velocity ratio as the velocity of a vertical well divided by the velocity of a horizontal well, and then substituting in the flow rate and cross-sectional area for each of those and establishing an equation.

In the next --

Q. Is this an accepted engineering equation for solving for this problem?

A. Yes, it is.

Q. All right.

A. In the next gridded block down there, I'm showing that the area of a horizontal well is equal to its circumference times its length and that the area of a vertical well is equal to its circumference, and that would be wellbore circumference times its pay thickness.

If you take the ratio of those two, the circumference falls out of the equation, so that ratio of area of the horizontal to the vertical is equivalent to the length divided by the pay.

So this equation boils down to needing four parameters, and those are shown in the next block, that being the flow rate from a vertical well, 300 barrels a day, flow rate in a horizontal well, 1600 barrels a day, pay thickness, 60 feet, length 2166 feet for the horizontal well.

If you plug those numbers into the equation, you get a velocity ratio of 6.8. And what that's saying is that in the Cabin Lake Pool, if we have a horizontal well producing at 1600 barrels a day and the equivalent vertical well at 300 barrels a day, there would be seven times -- approximately seven times higher fluid velocity in the vertical well.

Said another way, I could produce this horizontal well at 7 times the 1600 barrels a day, or approximately 10,000 barrels a day, and I would have the same fluid velocity as the vertical well.

Q. All right. The fluid velocity in the vertical well, then, becomes the benchmark?

A. That would be correct.

Q. All right. And you have found by engineering calculations that you could produce the horizontal well almost seven times faster than the vertical well, before you reach the same effects in the reservoir as the vertical well?

A. Well, one correction. It's actually -- I could produce it at 7 times 1600 barrels a day --

Q. Okay.

A. -- which would be, in effect, 35 times harder than a vertical well, approximately.

Q. So the fluid velocity relates directly to potential reservoir damage, and you have quantified that with a number?

A. That's correct.

Q. Give us some examples of why you as a reservoir engineer are concerned with reservoir damage. What do you mean by reservoir damage?

A. Well, I'm not sure I understand that question.

Q. Yes, sir. You're concerned about fluid velocity?

A. Correct.

Q. You want to control the rate at which you produce the horizontal well?

A. Right.

Q. What are you trying to avoid?

A. Damaging the well, just as a result of perhaps pulling in fluids, water --

Q. Okay.

A. -- fine migration. Damaging the well artificially because you're producing it at a high rate.

Q. And those three things are the typical examples that you as a reservoir engineer fear, the fines migration, the reservoir migration and -- or gas coning, water coning?

A. Right. They aren't all applicable here, but those are the general mechanisms at work.

Q. Okay.

A. If I might also add, in regards to this velocity, you know, having this computation is nice, but there really are practical examples. In terms of gas coning, we're using horizontal wells all the time to solve that problem.

Q. Do you have an example that you can relate to us?

A. Well, yeah, Phillips -- Well, as I say, many wells are doing this. Phillips is drilling two. We're drilling the second well in Oklahoma right now to solve this very problem.

The vertical wells go in there, and their fluid velocity is such that they pull in water and water out prematurely. They come in and drill the horizontal well, the fluid velocity is far less. And in fact, they're going to recover 10, 20 times what the vertical would, because it's solving the problem of water coning by reducing fluid velocity.

Q. Have you satisfied, yourself, then, if we're allowed to produce the well at a test rate up to approximately 1600 barrels of oil a day, that that is not going to result in reservoir damage?

A. That is correct.

Q. You're not asking for any special allowable, but you are asking to overproduce that allowable for the test period?

A. That is correct. In the --

Q. Let's talk about that. What, then, is the purpose of the test?

A. Well, again, the purpose is so that we can collect the data that we need to conduct rate-time analysis.

One step further so that I can get the permeability in skin, to evaluate the well, to determine if it needs a stimulation. And by evaluating this well, I'll then be in a position to evaluate the technology in this field and in other applications.

Q. Is there any better way to get this information than conducting a rate-time analysis?

A. No. The only other option is, as I stated, the drawdown-buildup test, and we have no intentions of running one because of the difficulty of running such a test in a well on artificial lift, not to mention it's a horizontal well on artificial lift.

Q. Let's turn now to Exhibit Number 14. Would you identify and describe that type curve?

A. Yes, this is the type curve that I would be using if we're able to -- if the test period is granted.

What it shows -- It's busy. It shows a family of type curves, and they would apply to any number of well configurations of length and pay thickness, wellbore size.

I've highlighted on each of our exhibits one line in yellow. I've done some preliminary calculations based on our length, pay thickness and whatnot.

So for this well, the very curve that I would be using to do the rate-time analysis is shown on your exhibit outlined in yellow.

Q. What do we do with it?

A. Okay, if the test period is granted, we'll then be in a position to collect the production data, and I would begin by simply plotting the data on log log paper.

With each passing month I would have a new data point, and over some span of time you would begin to see the trend.

If the trend is a very shallow decline, then you would be matching this yellow-highlighted curve somewhere up near the top, upper portion of it. If it has a very steep decline, you would be matching it somewhere near the bottom of the curve.

The whole point of obtaining a match is that once you've got a match, you can then -- It's very simple. You pick off a match point, and there are two equations shown in the upper right-hand corner of this exhibit -- t_D equals some stuff and q_D equals some stuff.

With the match point I would be able to plug in the match point, calculate the perm and skin. And that really is a summary of how you perform rate-time analysis.

Q. If you were in a reservoir that had flowing oil wells, then you might have the opportunity to run drawdown or buildup tests and run an analysis to see if there's -- what the results of that analysis would show?

A. That is correct. Flowing oil wells -- Flowing any kind of wells are good for drawdown-buildup tests.

Artificial lift, we just rarely run the test because it's very difficult to get the gauges in there.

And I might add, when you try to get the gauges in there, then you're faced with the problem of getting the well started, and it usually screws up the first part of your data, and that's the most crucial part.

So you kind of know, even if you can get the gauges in there and conduct the test, the early time data is going to be messed up and you're going to have trouble analyzing it.

Q. The difficulty in this pool is that we have every expectation and belief that you're going to have to pump this well to produce it?

A. Yeah, we know we're going to have to put it on artificial lift. We don't have any wells out there capable of flowing.

Q. Okay.

A. They're all on -- Well, they're vertical wells, they're on pump jacks. We expect this to be higher rate, so we'll put it on submersible.

Q. As a reservoir engineer looking to gather data to determine the performance of the well in this reservoir, how critical is it to you to have this test run at the initial producing point of the well?

A. It's absolutely vital. If you don't run the test from day one, you really can't conduct the test. As you move further out into the future and then you open a well up to a high rate, any benefit of seeing very different behavior is masked.

So if you can do it from day one, you're in good shape. If you do it later on down the road, it's going to be tough.

Q. Can you think of any other way to do it than to have the flexibility to produce this well at capacity initially within this first-year period, and if you obtain overproduction then to make that production up in the second year?

A. No, this is the only way.

Q. Have you some illustrations to show what you're trying to solve for?

A. Yes, the next two exhibits are an attempt to show you the impact of what we just talked about, starting from day one, or in fact coming back at a later date and opening the well up.

Q. Let's look at them both together. Let's start with 15. Identify that for us, and then identify 16, and then let's go back and talk about them.

A. Okay. What I did here is, I went into the reservoir model that I used to forecast the expectations of the well, and in this case I made an assumption that the well does not quite perform as we expected.

And what I'm showing here is -- In each case it's the same forecast, but in each case I tweaked one of the parameters. And then the parameters were selected because this is the crucial information to me.

The red line shows all of the same input data, except that I reduced the permeability slightly in the model, and if I allow that well to produce wide open, I get the character shown by the red line. The well would IP at -- oh, something, about 1270 barrels a day, and declining to about 200 barrels a day at the end of year two.

In the blue curve, I go back to the base case. And all I did here is, I kept the permeability the same but I imparted some damage on the reservoir. So I damaged it a bit. And it IP's at 900 barrels a day, and at the end of the second year it's down to about 250 barrels a day.

The point here is that this is the kind of location I could see on location or see from the actual production data.

As you can see, there's a very distinguishable difference between those two curves, and I would be in a perfect position to answer the question, is this well damaged or not? If it's damaged it will behave like that blue curve; if it's undamaged it will behave like that red curve with a much steeper decline.

If I can now go to the next exhibit, I'll show you what happens if -- This would be the case for the same two wells, but in the case that the test period is not granted, and so we are obligated to produce the well at the allowable rate of 561 barrels a day for as long as it can do that.

Again, you're seeing two curves, a blue one and a red one, the same data, except where they overlay on this curve the data is actually black because of the color.

And what we're seeing there is, both wells will be able to produce for approximately ten months at the constant rate. In about the eleventh or twelfth month they begin to decline, and at the end of the first year you're essentially -- that's the data I would be trying to distinguish between.

And it's not until the end of the second year that I even really see any difference between those curves. But I'd like to point out, that difference at the end of year two is approximately 50 barrels a day. That's the kind of rate that would get masked -- You'd be lucky to see that difference.

So the point here is, if I look at these two exhibits together, the one we just spoke about, Exhibit 16, there's no difference between those two. I can't tell you, I can't tell my bosses, I can't make any good reservoir engineering decisions as to whether that well should be stimulated or not.

I can't make any references as to what the reservoir quality is. I am not in a position to determine, was this well good or bad because the permeability was such, or is it good or bad because it's damaged? I'm basically working with blinders on.

If the test period is granted, referring to Exhibit 15 here, I'll be in a position to see, that's one of those two sorts of data, either the red or the blue, and I'll be able to do a type curve match and compute the permeability and skin.

Q. Tell us the essential components of the requirements for the well. How do you set it up so that you get the data that you need to run the analysis?

A. The basic requirement -- You know, we call it rate-time analysis, but it's really just fancy decline-curve analysis. And the basic requirement is that the well has to be able to decline, meaning you have to be able to bring the well on at a capacity rate or a very high rate, such that within the first month, second month, third month, it begins to decline, as opposed to artificially imposing some lower rate, in this case the project allowable, where the well wouldn't decline. It would make that rate for a long time.

So the requirement is, the well has to be able to decline.

Q. Once you establish initial rate for production, do you adjust the choke setting on the well?

A. No, you don't touch it.

Q. You start it producing and you leave it alone?

A. That's correct.

Q. All right.

A. Yeah, anything you would do to the well to alter its flow mechanically, imposes difficulty in the rate-time analysis. It can be handled, but it makes it more difficult.

Q. You --

A. Which gets to our intentions here. Our intentions are to put this well on, to install a submersible, to produce the well unaltered and get this data so we can get the permeability and skin.

Q. If you're not provided the test period, what happens? You'll then have to produce the well at the constraints of the 561 a day?

A. Yeah, if the test period is not granted, we would put the well on and we would produce it at 561 barrels a day, and I would just watch the monthly production.

The question I'd be looking for, trying to answer at that point, is, when does it fall off? When is it not able to make 561 barrels a day?

Q. And now you've lost the ability to get the data to determine permeability or skin effect?

A. Well, what I could do is, I could go in to my reservoir model and I can start playing with parameters and try -- and I can force it to say -- Let's take, for example, if the well declined in the tenth month. I can go in there.

But as Exhibit 16 shows, if that's the example of what happens, if I'm watching this production rate and in the eleventh month it declines, I've got two ways to answer that question, and they're very different and critical to me.

One is, I can say it has damage. And the other one is, I can say it's just a little lower reservoir quality than I anticipated.

Q. Well, stop for a moment. Can you then, if the test period is not granted, use reservoir simulation to bridge the gap, if you will, and provide you a unique solution that can tell you whether it's a damaged reservoir?

A. No. In fact, in the model I would have an infinite number of combinations to get the answer.

But again, the two critical ones at the extremes are, is the well damaged or is it not? Those are the two critical answers, and I would have really no way of knowing.

Q. Let's -- Have you tabulated and provide us a display to show the Division the production forecast for the test period and the overproduction?

A. Yes, that's --

Q. 17, I think it is, right?

A. Yeah. Yeah, it's the final exhibit. And what this is is, it's an exhibit serving two purposes.

One is to show you that the requested test period is in line with our expectations for the well. And the second one is to discuss the overproduction again and how we'll handle that.

What this is is -- The first column, of course, is the months, 1 through 12.

The second column, labeled "Production if Test Period is Granted", that is nothing -- that is the DEA-44 production forecast, identical to what you saw in previous exhibits, except here it's monthly.

Our expectation is that this well will come on at 1600 barrels a day and decline to approximately 600 barrels a day in the twelfth month. The initial rate of 1600 is in fact -- then consistent with what we're requesting, the 1683 rate, during the test period.

The next column over is nothing more than the project allowable so that we can compute overproduction.

The overproduction is shown in the next column. And if we take, for example, month one, if we're able to produce the well at 1600 barrels a day and the project allowable is 561 barrels a day, we would be overproducing by 31,000 barrels.

In month two, we would fully expect -- Well, the well would decline to 1425 or something similar to that. The project allowable is 561, and so we'd have 26,000 barrels of overproduction.

The final column is the cumulative overproduction, and it's nothing more than a running total, so that at the end of month two we're at 57,000 barrels, and at the end of twelve months we would have accumulated 147,000 barrels of overproduction.

At the bottom of this exhibit I have year one summaries, and I'll go through those briefly.

The total production of 352,000 barrels, that's simply the -- our expectation of the well in year one.

That's the sum total of all those rates shown in the column of our expectations.

The next -- The annual allowable of 205,000 barrels, that's nothing more than the daily project allowable, 561 times 365. So it's the annualized allowable. So the difference between those two numbers is the overproduction, consistent with what you're seeing in the cumulative overage column.

So what we are saying here is that we have a well that we think will IP at 1600 barrels a day, and we're asking for permission to produce this well at 1683 so that we can get the data that would be similar to what you're seeing in column one, so that we can perform the rate-time analysis.

Q. At the end of the first year, if in fact there is any overproduction, your plan would be to meet with the area supervisor of the Division and work out a schedule for making up the overproduction so that at the end of the second year you would have made up the overproduction?

A. That is correct.

Q. All right. And if you haven't, then the well is subject to shut in until it does?

A. That is correct.

Q. You're not asking that any overproduction ever be canceled?

A. That is correct.

Q. Okay. Bass Enterprises Production has expressed a concern with regards to the project, and I have shared with you Mr. Carr's pre-hearing statement, did I not, Mr. Schramko?

A. Yes, I have a --

Q. Do you have a copy of that before you?

A. Yes.

MR. KELLAHIN: Mr. Examiner, Mr. Carr's pre-hearing statement files on behalf of Bass the following statement. It says, Bass Enterprises Production Company is concerned that the testing allowables sought by Phillips will adversely affect its interests in offsetting tracts and will therefore participate in the hearings to protect these interests.

Q. (By Mr. Kellahin) Let me ask you a hypothetical, Mr. Schramko. Let's assume the roles are reversed and you are the reservoir engineer for Bass and you have the offsetting acreage. How would you view the project from that perspective?

A. Intuitively, I understand the nature of their protest. They see us coming here and asking to produce the well at 1683 barrels a day. I have offsetting tracts of land that are undrilled, and it doesn't feel good.

But if you think it through a little further, then I'm really at a loss as to why they are protesting.

On the other hand, if I'm Bass, what I see is, I have undrilled acreage to the south of me, to the south of the horizontal well. The way you're going to prove reserves on that is to see a well drilled on our acreage, in this case, a horizontal well, so that if this horizontal well is successful and everybody can deem the well is successful, then we've proved their acreage.

So if I'm Bass, you're -- Phillips is taking the risk, they're proving the technology, the ability to drill horizontally in this reservoir, and they're proving up my reserves on my acreage. So to me, if I'm Bass, I see you doing all the -- taking all the risk, and I'm reaping all the reward.

Q. With regards to this project, has Bass committed any financial resources to your effort?

A. No, none.

Q. So there's no cost component to them in the risk you undertake to determine if this technology will work?

A. That is correct.

Q. Okay. Would you be concerned -- You deal with drilling on federal leases. If you're the offset operator with the undrilled tract and the other operator drills either a vertical or horizontal well adjacent to you, what's going to happen?

A. They're -- Within a short period of time, they would get an offset drainage notification.

Q. Regardless of the ability of the well to produce any portion of the reserves, you get the notice, right?

A. Yeah, regardless of what production rate our well produces at, they're going to get that notification. The fact that the well is there, they're going to get it.

So we -- I've heard and I understand that one of their concerns is that they're going to get this offset drainage notification. Well, they're going to get that anyway, with or without the test period.

Q. Would you be concerned about the shifting of allowables during the test period so that you could produce at these test rates?

A. No, I wouldn't. Again, we're not proposing to produce this well at high rates and not make up the overage. The fact that we're willing to make up the overproduction, there's no correlative-rights issue here.

Q. Are you satisfied that the reservoir is large enough and contains enough recoverable oil that the 147,000 barrels of oil overproduction can in fact be made up?

A. Well, yes, as I -- I think I stated earlier that that would represent five percent of the oil in place, across the project area.

If you think about it from a drainage standpoint, then in fact we're talking -- we could expand this problem and say, Well, now we're talking about potentially six tracts of land. That would be 6 million barrels of oil in place. We're asking to pull out 150,000 barrels.

So for us to be -- What we're saying, then, is we're pulling out 2 1/2 percent of the oil across our three drill tracts and the three drill tracts just south of us. So now we're talking about an overproduction of 2 1/2 percent instead of five, and so it's even a smaller issue in terms of drainage.

Q. So if you're the Bass reservoir engineer, you're not going to be concerned about drainage from the Phillips project?

A. No, the fact remains, they're going to produce the same volume of oil out of their tract whenever they drill their well, because we'll make up the overproduction.

Q. In summary, what are your conclusions and recommendations to the Examiner, Mr. Schramko?

A. Well, we have the three requests.

First, obviously, we're asking for permission to drill the well and establish the 120-acre proration unit needed to drill the well.

We're asking for the project allowable of 561 barrels a day, which is consistent with other horizontal wells that have been drilled in New Mexico.

And finally, we're asking for the special test period that will give us the opportunity to produce the well at high rates during this first year, with the constraints that I've described during the first six months and the second six months, and make up that overproduction during the second year so that there would be no overproduction at the end of 24 months.

MR. KELLAHIN: That concludes our presentation, Mr. Examiner. The final exhibit is my certificate of mailing of notification. That's Exhibit 18. The only party notified was Bass Enterprises Production.

We would move the introduction of Phillips' Exhibits 1 through 18.

EXAMINER CATANACH: Exhibits 1 through 18 will be admitted as evidence.

MR. KELLAHIN: That concludes my direct examination of Mr. Schramko.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Schramko, what is the well going to be making per day at the end of the second year, according to your reservoir model?

A. It would be about 300 barrels a day.

Q. So you're going to have in excess of 300 barrels a day allowable, or approximately 200-and-some barrels a day allowable that you could use to make up the overproduction; is that correct?

A. That would be correct.

Q. So are you really making up the overproduction if you have excess capacity at the end of that second year? Isn't there a portion that's not really being made up?

A. Let me answer the question another way, because no, all overproduction would be made up.

Referring to the final exhibit so you can see the numbers, at the bottom there where I say the annual allowable is 205,000 barrels, so twice -- The allowable that we'd be allowed to produce at and have no overproduction over a two-year span would be twice that number, 410,000 barrels.

What we are saying is, we will produce this well until we have cum'd 410,000 barrels, and that's it. If need be, we'll shut the well in for the balance of the two years. So we won't produce one barrel more than 410,000 barrels during the two-year period.

Does that answer your question?

See, you are correct that if we produced the well and at the end of 24 months we're making 300 barrels a day -- The problem with that scenario is that we would have in fact produced more than 410,000 barrels.

Q. Well, you're going to be cut back probably from the 300 barrels a day that you would be able to make --

A. I estimate --

Q. -- but you still have the excess capacity of 250 or 260 barrels a day that --

A. Right, but that wouldn't --

Q. -- the well is capable of making.

A. Right. I estimated that for us to balance the well out at the end of year two, we could produce the well at approximately 150 barrels a day, for the balance of year two. And at the end of that second year the overproduction would be zero.

So that's one possible outcome of this. We conduct the test, as we said, we contact the District Office, and we agree to produce it at 150 barrels a day, or whatever the number is exactly.

Q. What you're looking to determine with the test period is, as you said, to determine permeability and skin effect, and to determine if there's been any damage to the formation, to the reservoir?

A. Skin is, in effect, that damage component.

Q. Can you not determine that from your initial producing rate, being that you already have the thing modeled? Can you --

A. Well -- No. The idea of what could happen -- one is, I might have -- If we do this in a very simplistic way, if I estimate the well will produce at 1600 barrels a day and you tell me I go out on location and it produces at, say, 1200 -- or let's say 800 because it will make the math easier.

If It produces at 800 barrels a day, I can get there in one of two very different ways. All I'd have to do is go into my model and cut the permeability in half. Okay? And that would reduce the initial production rate by a factor of two.

Another way to get there -- and I can't tell you the right now; I'd have to play with it a little bit -- is, I could leave the permeability alone and I could start -- I can go into any damage component and just start saying it's damaged a little bit and see if that brings it down to 800. Is it damaged a lot? And I might find out, yeah, if I impart a lot of damage on it, I can have the permeability I said and produce the well at 800 barrels a day.

So there are two very different ways of arriving at the answer, and I need to know the difference.

Q. Well, don't you have some good permeability data from your other wells?

A. Not really, not when you're talking about reservoir modeling. We do have some permeability data.

But cored perms, for example, they are conducted with air, air blown through the core, and those are traditionally very different than what you would experience with oil. That's the bulk of the data we have.

Now, it does put you in an order-of-magnitude kind of range, and that's what we're using here. I'm saying the permeability range is between 2 and 5 millidarcies. But that isn't very significant when you're trying to get a general understanding of a well's behavior.

But it is significant when all of a sudden you start trying to determine, why didn't this perform as expected? Is the answer one millidarcy? Is it -- or is it -- It could even be higher permeability than I said and have a lot of damage.

If I can conduct a test, either a drawdown-buildup or rate-time, then I'm in a position to answer the question exactly, or at least close enough that we can make good engineering decisions.

Q. Okay. Is it going to take that year period to determine whether or not you have damage?

A. Realistically, yes. I mean, what we're talking about is, we'd have twelve data points, and I'm going to be using twelve data points to establish a unique trend.

You know, obviously, two data points doesn't establish a trend. Three starts to. And the more data you have, the more comfortable you get with the trend.

And then you interject on that production problems that you might have in the field, power outages, anything that could cause this submersible to go down. It's going to tinker one or two of the months' data, on the low side, probably.

So by having twelve data points, if during three or four of those months there were some artificial problems in the field, something related that kept the well from producing at full rate, I can discard those four points and conduct it with the remaining eight, in a sense.

Q. Once you have all the data points you need and you've determined that there is some damage, what do you do?

A. We'd go into it with coiled tubing and acidize the well. The procedure would be, you'd run in and push the coiled tubing out to the end of the well, and then squirt the acid using special downhole tools, and then bring the well back on.

I might add, it's a costly procedure, it's $50,000.

But the bigger component in my mind, it's a risky operation. Coiled tubing is not meant to be pushed out in horizontal wells, and the possibility remains that you twist it off, in which case then you're faced with a major workover. In the worst case, maybe even P-and-A'ing the well, but I mean that's not really likely. But you could be faced with a major workover.

And another part of this is that we get -- The test period would give us some flexibility in actually what submersible we put in the well. Right now I'm now sure if -- Without the test period, you're not really sure what sub to put in there.

So what will probably happen is, we'll put a sub in there that will handle about 1500 barrels of fluid a day, total, if the test period is not granted. And I would do that because the expectation would be that the well would make about 50 percent water, 50 percent oil, give or take, and so that submersible size would cover that range of applications.

But I can very easily foresee having to work this well over to change that sub out, because our estimate was off significantly and the existing sub can't handle it. If the water cut is significantly different, we might need a much larger sub or a much smaller sub.

And then you're working the well over and possibly damaging the formation, and you get back into the damage component. You're trying to avoid that at all costs on horizontal wells. We're going to go to great lengths to drill this well and not damage it. So I'm a great stickler for not working these wells over unless you just flat out have to.

Q. After the test period is over, can you actually quantify the damage, and do you go in when there's minimal damage and do a workover?

A. Well, once I can quantify that damage in terms of the reservoir model -- I mean that might be a skin of -- well, in vertical terms, which you're probably more familiar with, a skin of plus 5 is significant. When you're working with horizontal models, a skin of plus 2 is very significant. So it's slightly different terms, so I say that so that you're clear.

I might go in to my model and put in a skin of plus 1, and that matches and everything's fine and I've got it pegged.

Then all I have to do in my model is say, Well, what if the skin was zero? and see what the production rate would be. Because see, what I would also get out of this test is the actual permeability.

So in effect I'd be forecasting the well's production, and I could say -- I could play the "what if" game: What if there was no damage on this well? Meaning what if the skin was zero? And then I could see what the benefit is, and it would be pretty exact.

I mean, I'd say, well, it's currently producing, say, 1200 barrels a day with a skin of plus 1, and if I change it to 0, I can bring it up to 1600 barrels a day, compute that, and it would probably make sense to go in and acidize it.

So yeah, if we can run the rate-time test we'll be in a great position. I'm not going to stand here and say the numbers are exact, any more than I would say that for a drawdown-buildup test. But they're certainly very good numbers for telling you what the benefit is of stimulating the well.

Q. What is the ultimate benefit of going in and performing a workover on the well? Would it increase, do you think, ultimate recovery?

A. You mean a stimulation job?

Q. Yeah, stimulation.

A. Well, the way you asked it -- I'd like to answer that, because see, I have this feeling -- I should say it's more than a feeling; it's an engineering assessment -- that if you work over a horizontal well, you're obligated to pump kill fluids in it. And it would be nothing more than a brine, but you pump those in the well.

In the case of a horizontal well -- Well, any kill fluids can be a damaging element. So any workover we do, even if it's just to change a sub out, we're going to have to pump kill fluids in the well. We want to avoid that because you could damage the well and -- You know, just going in with an acid job doesn't guarantee you're going to clean it up. So there's no guarantees here.

But at least you'll know going into the project that you will be putting acid on the formation, you will be attempting to clean it up, you can do everything you can to clean it up.

And generally speaking, you will get some gain from it. Whether you would get everything would remain to be seen.

So I can't really quantify the exact nature of what the acid work would do. But I could certainly do this: I'd be in a position to do an acid job, see what the results are, and now that I've got everything pinned down, I can see if I got that actual benefit. If I didn't, I might think of another way to do the acid work and try it again, if the potential gain is worth it.

Now, to that end -- I mean, that benefits both the state and Phillips in the sense that if the well is damaged it's just not going to perform. And that is the key element in a horizontal well. That's the first issue that always come up: Are you going to be able to drill it without damaging it? Are you going to be able to complete it without damaging it? Are you going to be able to keep the well in a producing mode without damaging it?

So the test period provides us every opportunity to do everything we need to do without imparting any risk.

Q. Why wouldn't you perform the stimulation or the -- at the onset, when the well is drilled and completed? That's --

A. Cost, risk. I mean, we do that all the time with vertical wells. I mean, you know, I maybe have permeability and skin on one percent of my vertical wells.

And that is the general answer. You drill it before you even know anything, you perforate it and you acidize it. It's very standard, because you're talking about $3000.

Here we're talking about a $50,000 operation, and that's insignificant, relative to the total cost of drilling. But the bigger issue is this coiled tubing. You don't just rig up a pump truck and pump down your well.

In this case you're working with coiled tubing and, you know, the limitations of coiled tubing -- You're reaching those limits, because as you cut that corner through the curved portion of the well and start going out, that coiled tubing is now rubbing on the entire length of that curve, and there's all sorts of things that can happen. They can get stuck. If there's any trash in that well, that coiled tubing could get stuck. There's a number of things that can go wrong, and then you're stuck with a fishing operation on your hands.

So it's not something that I would -- I've had this discussion with my folks in our office. I will not acidize the well from day one. One way or another, we're going to put the well on, see what it will do. And with or without the test period, I'll have to make a call at some point.

Without the test period, it will be an impossible call, it will be a hip shoot to determine when -- Well, we probably would not acidize it, because if the test period is not granted, we're not going to come back and ask for it in that sense.

So I'll just wait till the well declines. That might be 10 months, 14 months. And then I'll attempt to do what I showed you on that one exhibit. I'll be trying to distinguish between two curves that are very difficult to distinguish between, and I'll just make my best estimation. And so it might be two years down the road before we'd acidize it.

Q. What would the ultimate difference be if you did acidize it two years down the road, as compared to maybe a year down the road? I mean, what's going to be the ultimate difference of doing that?

A. Oh, you'd probably be getting into economic-limit questions.

I think the more significant question would be that -- I guess the answer to your specific question would be, I couldn't quantify it, and I would have to say probably not a whole lot in terms of the ultimate recovery. But I would add that there's a fair chance that maybe we don't acidize it.

I mean, if the well is produced at 560 barrels a day for 10, 12, 14 months, that pretty much meets our expectations of the well. It would be a very logical conclusion to say to yourself, I guess it wasn't damaged. And so there would be that nagging interest that says, wait, it's not damaged, when in fact maybe the reservoir is in fact of higher quality than we estimated, and it is damaged.

In which case, you would probably make the decision, don't acidize because it's everything we thought it might be.

And in that case, you might lose -- Oh, I'm hip-shooting here a little bit, but I would say maybe upwards of 100,000, 150,000 barrels of ultimate recovery, because the well would decline differently, and the stimulated well would, of course, recover more reserves.

And in the case of a horizontal well they would be pretty high.

Q. Your opinion is that producing at that high rate for the first year is not going to harm any -- It's not going to cause excess drainage from any of the offset tracts?

A. That's correct.

Now, in fairness, I'll say, you know, there is movement of fluids in reservoirs, there is movement. And there's the good possibility that some oil from Bass's acreage could move towards ours. But over a two-year span it's going to be identical.

And we're talking about such a relatively small amount of oil, 2 1/2 percent -- In terms of a drainage issue, it's 2 1/2 percent of the total oil that we're asking to move, temporarily.

The key question, though, is, what would their ultimate recovery be with or without this test period? And it will be identical.

Whether they drilled it in the first month, the 12th month, 24th month or two years, five years down the road, their ultimate recovery will be the same, with or without the test period.

Q. The million barrels, is that -- That's original oil in place per tract --

A. Correct.

Q. -- per 40-acre tract.

The recoverable is -- 600,000, did you say?

A. Well, that's the horizontal. A vertical would be 200,000, or approximately 20 to 30 percent of that million.

Actually, we have recoveries of a vertical well estimated at about 26, 27 percent.

Q. And in a horizontal well, what was the --

A. About the same recovery, 25 percent.

If we had an water-coning or gas-coning problem here that we were trying to solve, then it would be reasonable for me to say the recovery from a horizontal well would be higher as a percent.

In this case, you're not really combatting any of those components, so you don't really have any real positive aspect working for you in the horizontal well. So it would be reasonable to say the recoveries would the same.

And of course, that's the basis of 600,000, 20 to 25 percent of approximately 3 million barrels.

Q. Did you mention that there were different producing intervals in this well, or in the proposed well? In the field?

A. In the field -- Of course, that was the nature of our discussion back in 1993. We have -- Well, the vast majority of the wells, all but about two or three of them, were drilled to the Bone Spring and completed in the deeper Brushy Canyon, and that's at about 7000 feet.

Okay, so we have Brushy Canyon pay straddled around this field. That's about 20,000 to 30,000 barrels of oil recovered per well in that zone.

We also, on occasion, find another zone in the Brushy Canyon, about 800 feet higher than that, so somewhere around the 6400-foot depth; again another 20,000 or 30,000 barrels of oil out of it.

Then this good Cherry Canyon zone, and nothing higher than this.

So we're talking about three potential zones in the Cabin Lake-Delaware Pool.

Q. Okay. This is by far the most prolific zone, the target zone -- ?

A. Far and away, that's right. It represents probably 90, 95 percent of the total recovery. The total reserves that are taken out of this field will come from that zone.

Q. The other zones that are potential will remain unproduced in your tract?

A. That's correct. We have debated in our own shop as to whether they're even economic to drill for. So you're talking about drilling an incremental 1400 feet, casing an incremental 1400 feet, cementing an -- completing.

By the time you add it up, producing 20,000 to 30,000 barrels of reserves is borderline economic anyway, so -- In fact, in a number of wells we have only drilled to this zone, for that reason.

So it's questionable. I would make the statement that you're really not leaving behind economic reserves. They are marginal at best.

Q. Is this all a single lease, this whole project that we're -- ?

A. No, the acreage we're referring to where this well will be drilled is the James E. That's federal acreage. That would be Sections 11 and 12, 11 and our portion of Section 12. To the north in Section 2 is the James A; that is a state lease.

Q. No, what I'm referring to is the three 40-acre tracts you're you going to drill on. Is that common?

A. No, that's one lease.

Q. That's one lease?

A. Yes.

Q. All commonly owned?

A. Yes.

Q. Okay.

A. Yes. Yes, commonly owned, and a hundred percent Phillips.

Q. Do you anticipate you'll be able to take the well out 2000 feet or so?

A. Yeah.

Q. Have you guys done a horizontal well previously?

A. Within our office we've drilled one. It was in Texas, a different reservoir, shallower. But yeah, we're confident that the technology is there to drill that far.

EXAMINER CATANACH: Okay. I think that's all I have, Mr. Kellahin.

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

EXAMINER CATANACH: Ms. Trujillo, did you have any questions of the witness?

MS. TRUJILLO: No.

EXAMINER CATANACH: You can go ahead and make your statement at this time.

MS. TRUJILLO: I have a letter addressed to Mr. Stogner from Wayne Bailey at Bass Enterprises Production Company. It says,

Dear Mr. Stogner:

On behalf of Bass Enterprises Production Company, this is to state Bass's objection to the Application by Phillips Petroleum Company dated June 14th, 1994, whereby Phillips has proposed the drilling of the James E Well Number 9 as a high-angle/horizontal directional drilling pilot project. Bass is the owner of leases offsetting the entirety of the James E. Well Number 9 wellbore, said Bass leases being located in Sections 12, 13, 14 and 15 of T22S-R30E, within the James Ranch unit.

Paragraph 5(e) of the above Application proposes an exception to Division General Rule 502 to establish a test period allowable. Bass hereby objects to the requested test period allowable as being exorbitant and unreasonable. Furthermore, due to the close proximity of the proposed wellbore to Bass's leases, the test allowable creates an undue hardship on Bass to avoid competitive drainage and satisfies its obligations of the leases offsetting the proposed wellbore. According to the proposed test well allowable, Bass cannot effectively protect its leasehold from offset drainage, even with the drilling of three vertical wells, and therefore Bass hereby requests that Phillips' test allowables be limited to 561 BOPD.

This statement is not intended to limit Bass's objection to the subject Application on other grounds in the future. Bass has filed the appropriate notices with the NMOCD in order to reserve its right to appeal any order granted to Phillips as a result of the subject Application and testimony presented at the July 7th, 1994, hearing.

Signed, Wayne Bailey.

I have nothing further.

EXAMINER CATANACH: Okay, did you want to enter that as an exhibit?

MS. TRUJILLO: I did. Unfortunately, I didn't bring copies at this time. Could I submit them later this afternoon?

EXAMINER CATANACH: Yes, you may.

MS. TRUJILLO: Okay.

EXAMINER CATANACH: Mr. Kellahin?

MR. KELLAHIN: Mr. Examiner, I think Mr. Schramko as an expert witness and a qualified reservoir engineer has sufficiently addressed the Bass concerns.

Mr. Bailey is a landman with Bass and is not a technical expert. We have chosen not to present an engineering witness to validate the contentions they have made.

I believe the record is complete with Mr. Schramko's conclusions with regards to their concerns. Bass cannot simply sit there and not drill. We are affording them the opportunity to learn by our experience.

And it escapes me as to why Mr. Bailey as a landman would argue that they cannot effectively protect their leases from drainage. We're giving them the chance to learn by our effort, at our cost. And if he chooses not to drill his leases, then correlative rights is simply the opportunity, and he has lost that opportunity.

I have a -- Mr. Stogner gave me the original. I will submit that to you.

If you would like to ask Mr. Schramko any clarifying questions about the letter, he's certainly available, and perhaps now is the time to do it.

EXAMINER CATANACH: I don't have any further questions.

MR. KELLAHIN: All right, sir. That concludes our presentation.

EXAMINER CATANACH: There being nothing further in this case, Case 11,014 will be taken under advisement.

(Thereupon, these proceedings were concluded at 10:16 a.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11014, heard by me on July 7 1994.

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 July 11, 1994.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1994

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

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

APPLICATION OF PHILLIPS PETROLEUM COMPANY)

CASE NO. 11,014

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

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

September 23, 1994

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on Friday, September 23rd, 1994, at Morgan Hall, State Land Office Building, 310 Old Santa Fe Trail, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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INDEX

September 23rd, 1994
Commission Hearing
CASE NO. 11,014

* * *

E X H I B I T S

Applicant's	Identified	Admitted
Exhibit 1	17	69
Exhibit 2	22	69
Exhibit 3	23	69
Exhibit 4	24	69
Exhibit 5	25	69
Exhibit 6	26	69
Exhibit 7	28	69
Exhibit 8	38	69
Exhibit 9	40	69
Exhibit 10	40	69
Exhibit 11	46	69
Exhibit 12	48	69
Exhibit 13	48	69
Exhibit 14	53	69
Exhibit 15	54	69
Exhibit 16	64	69

* * *

Bass

Exhibit 1	102	123
Exhibit 2	102	123
Exhibit 3	103	123
Exhibit 4	104	123
Exhibit 5	105	123
Exhibit 6	106	123
Exhibit 7	107	123
Exhibit 8	107	123
Exhibit 9	109	123
Exhibit 10	111	123
Exhibit 11	112	123
Exhibit 12	115	123

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By: MICHAEL B. CAMPBELL

* * *

WHEREUPON, the following proceedings were had at 8:06 a.m.:

CHAIRMAN LEMAY: Good morning. This is the Oil Conservation Commission, its second day, to consider Case Number 11,014.

MR. RAND CARROLL: Application of Phillips Petroleum Company for a non-standard oil proration unit, an unorthodox oil well location, a high-angle/horizontal directional drilling pilot project, special operating rules therefor, a special project oil allowable and production testing period, Eddy County, New Mexico.

CHAIRMAN LEMAY: Appearances in Case 11,014?

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin.

I'm appearing today in association with Ms. Elizabeth Harris. She's an attorney and member of the Texas Bar and Phillips' in-house counsel, stationed in Odessa, Texas.

We have one witness to present.

CHAIRMAN LEMAY: Thank you.

MR. CAMPBELL: Mr. Chairman, my name is Michael Campbell. I'm with the law firm of Campbell, Carr, Berge and Sheridan, appearing on behalf of Bass Enterprises Production Company.

CHAIRMAN LEMAY: Thank you very much.

Before we start, I failed to introduce our new Commissioner to the right. You had Gary Carlson yesterday. We have Commissioner Jami Bailey today, representing the Commissioner of Public Lands.

The other two Commissioners you'll recognize as being the same.

Mr. Kellahin, you may begin.

First, let's swear in the witnesses. Those giving testimony, please stand.

(Thereupon, the witnesses were sworn.)

CHAIRMAN LEMAY: Mr. Kellahin?

MR. KELLAHIN: Mr. Chairman, let me provide a brief outline to you and the other Commissioners so that you can see how we got here and what we're asking you to decide today.

First of all, by way of comment, Ms. Harris is making her last appearance before the Commission. She's been here a number of years representing her company before the Division. She has the distinct privilege of being transferred to the Phillips London office. It's a major improvement for her. I believe there's water in London, as opposed to Odessa. She's pleased, and we're delighted with her success.

CHAIRMAN LEMAY: We want to wish you every good luck in your new assignment, and if we ever get over there to do any kind of regulation in the North Sea, maybe we'll see you in the proper forum in London.

Good luck to you.

MS. HARRIS: Thank you.

CHAIRMAN LEMAY: And thank you for your past service before this Commission.

MS. HARRIS: Thank you.

MR. KELLAHIN: My second comment has to do with my representation.

Mr. Campbell and Mr. Carr and I do a number of cases, his firm and my firm, before this Division. There are probably no more than four or five lawyers that practice before you on a regular basis, and we go considerably out of our way to avoid conflicts.

In this situation, however, I am now appearing in a case for Phillips which is opposed by Bass, normally one of my clients. I want you to be assured that the parties are aware of the potential conflict, and they have waived it in this matter.

Historically, I've represented Phillips in the Cabin Lake area, and simply by happenstance the southern exposure of this reservoir butts up against the Bass interests, and there are some points in this case that are of concern to them.

This case involves another one of those wonderful little, unique, single examples of something to do in the potash area.

The circumstances, as Mr. Schramko will outline to you -- he is our reservoir engineer -- is that as development has taken place towards the southern end of current development in Cabin Lake -- this is Delaware oil, 40-acre oil spacing -- he has found the opportunity to continue to develop his spacing units with the limitation that the BLM Carlsbad is restricting his well location because of their belief in the presence of mineralization of potash.

He has determined that he has an unorthodox surface location in a 40-acre tract and that in order to access the adjoining two 40-acre tracts, he will horizontally drill this well, so that he will intersect three consecutive 40-acre tracts that are laid down on a 120-acre spacing unit.

His plan that he proposed to the Examiner, Mr. Catanach, was that we would follow the convention of the Division, we would honor the side boundary setbacks for the producing lateral of the horizontal well so that in no circumstance would we be closer than 330 feet to the outer boundaries.

In addition, the producing allowable for the horizontal well would be the special oil allowable for 40 acres, which in this pool is 187 barrels a day, times three. And that is the convention of the Division for the horizontal wells.

It is my understanding that none of those issues are opposed by Bass, and all of those matters have been approved by the Examiner.

The matter at issue and the part of the presentation that we want to focus on is that, while Mr. Schramko will lead you through the summary portion of what I've just described, the substance of his presentation is this, that he is recognized within his company as a rate-time analysis expert, that his firm engineering conclusion is that he needs the opportunity to conduct a special test on this wellbore to determine its productivity, and so that he will have reservoir data by which he can determine whether or not this well is experiencing simply low permeability or it has high permeability but is exposed to some skin damage.

Now, he is a recognized expert in his company. He's going to tell you in detail how he's analyzed the well and what he proposes to do with the test.

The end result is that he originally asked the Division Examiner for the opportunity not to increase the allowable, but to have a special test period. He proposed that for the first twelve months of production, that he be allowed to produce this well up to a maximum daily oil rate -- 1620, wasn't it?

MR. SCHRAMKO: 1683.

MR. KELLAHIN: 1683, 1683 barrels a day.

The purpose of the test, as he will tell you, is to provide a sufficient drawdown of the reservoir that he can have data separation so that he'll know early in the life of the well what's happening.

If he is confined to the 561 barrels a day, which is the depth bracket allowable times three, then his concern is, he will not have the ability to produce the well at capacity early in the life of the well, to realize the differential by which he in his expert opinion can reach some engineering judgments.

In order to not impair the correlative rights of Bass, which owns the south portion, it will be Mr. Schramko's testimony that once he has conducted the test, that he will take the next year and balance any overproduction that he's attained at the end of the first year, so at the end of the second year he's balanced back with the reservoir, and if Bass ever has a well offsetting the property, then there's an opportunity to avoid any uncompensated net drainage.

Bass presented a letter in opposition at the Examiner hearing. It is our understanding and belief, and

Mr. Schramko's testimony, that in order to meet the Bass concern he has re-examined his proposed test period, and he's going to request that you modify the test to reduce it to a six-month period.

It is our understanding that they were concerned about the length of the test, and to accommodate their concern, while we believe it's not necessary to do so, we're going to reduce the test, and his testimony will be a six-month period. The other parameters would be the same.

At the end of six months, then, he would balance any overproduction in the subsequent six months so that at the end of one year, as opposed to two, it will be balanced in the reservoir.

It will be his testimony that there is sufficient recoverable oil in this area that the magnitude of oil produced during the test period is so small, so small, that it will not have any effect on correlative rights.

His ultimate conclusion will be that in the absence of the test, there could be at-risk recoverable oil that is not otherwise recoverable, and his estimation under the example he'll present to you, that could be 100,000 barrels of oil.

That's what we're here to do and what we're here to show you.

Thank you.

CHAIRMAN LEMAY: Mr. Campbell?

MR. CAMPBELL: Briefly, Mr. Chairman, this is the first notice that Bass has had of an adjustment of the test period.

It is our view that the effort here by Bass to obtain technical data, while otherwise laudable, comes at the expense of impact on the correlative rights of Bass to the south and perhaps to the east.

The technical data that was presented at the Hearing Examiner's hearing by the same engineering witness, we believe, is not the type of technical data by which we can examine the correlative rights impact of offsets.

We have undertaken, Bass has, Mr. Platt will confirm, engineering studies which demonstrate that the test period now at six months and the overproduction during that six-month period will not be made up, that these -- because of the reservoir characteristics, Bass will never recover a drainage caused by this test.

That may be impacted as a matter of degree by reducing the test period. But nonetheless, we will experience an impairment of our correlative rights that we cannot correct, even should we drill a well offsetting to the south. Our studies assume that we will drill such wells, and nonetheless, we don't think we'll be able to recover.

So we will continue to oppose the Application and believe that our data will demonstrate that the decision of the Hearing Examiner denying this Application should be sustained.

Thank you.

CHAIRMAN LEMAY: Thank you.

Mr. Kellahin, you may proceed.

MR. KELLAHIN: Mr. Chairman, we would call Mr. Ken Schramko as our first and only witness.

KEN SCHRAMKO,

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. Schramko, for the record, sir, would you please state your name and occupation?

A. Yes, Ken Schramko, I'm a senior reservoir engineer for Phillips in Odessa, Texas.

Q. Summarize your education for us, Mr. Schramko.

A. I obtained a BS in petroleum and natural gas engineering from Penn State University in 1980. Since that time, I've been employed exclusively by Phillips. I've worked in eight different offices over the last 14 years.

Q. Describe for us the circumstances of your current employment, insofar as it deals with Cabin Lake.

A. I've been in Odessa, Texas, for approximately a year and a half, and since that time I've been responsible for all reservoir engineering in New Mexico, with one of my primary focuses being the Delaware formation.

Q. Have you appeared as a technical expert witness in the field of reservoir engineering before the Division Examiners with regards to hearings on prior occasions in the Cabin Lake-Delaware Pool?

A. Yes, I have.

Q. In addition, have you conducted an engineering study with regards to the drilling, completion, operation and special test period for the well that's the subject matter of this Application?

A. Yes, I have.

Q. This is identified as the James E Well Number 9?

A. That is correct.

Q. Were you the technical engineering witness before the Examiner when the Examiner heard the Examiner-level hearing in this case?

A. Yes.

MR. KELLAHIN: We tender Mr. Schramko as an expert reservoir engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) Separate and apart from appearing in this case, have you appeared before the Examiner in any other case involving the Cabin Lake-Delaware Pool?

A. Yes, I have.

Q. What was the purpose of that case?

A. It was in this same field. It was in October of 1993, I believe.

Q. Yes, sir.

A. The allowable in this field had been established at 107 barrels per day, based upon the drilling of the discovery well, the James A Number 2. That well was drilled to a depth of approximately 6000 feet, and so the depth bracket allowable for the field was 107 barrels a day.

Q. What member of the Delaware formations was that well initially tested and discovered in?

A. The Cherry Canyon, one single member in the Cherry Canyon portion of the field.

Q. As a result of that initial well being completed in that member of the Cherry Canyon, what happened in establishing for the pool a depth bracket oil allowable?

A. What happened was, the well was completed in the Cherry Canyon and the depth bracket allowable for that completion, as stated by the NMOCD, is 107 barrels per day.

Q. What happened with regards to subsequent development in the pool after the initial discovery well?

A. If you're looking at Exhibit 1, you'll see there have been in excess of 30 wells drilled in this field. And with the exception of one other well, all wells were drilled deeper through the Brushy Canyon on into the Bone Springs and were completed at depths ranging between 7000 and 8000 feet.

Q. Did Phillips make a request to the Division in this October case to do anything about the allowable for the pool?

A. Yes, we felt that the allowable in the pool should have been 187. Phillips was the -- one of the early discoverers of the Delaware. This field is generally touted in that fashion. And we felt like we were impaired, or this field was impaired, with an allowable based upon a discovery well, when all other wells -- Had we known that the deeper Brushy was productive initially, we would have drilled to that depth initially.

So we were asking that the allowable be based on the depth bracket of the deeper Brushy Canyon members.

Q. And what was the outcome of that Application?

A. That was successfully granted, the allowable was granted, 187 barrels a day.

Q. As we look at your exhibits, you have proposed to introduce Exhibits 1 through 16. Do those exhibits represent your own work product?

A. Yes, they do.

Q. In each and every instance, then, this is information that you have examined, prepared or made interpretations from?

A. That is correct.

Q. Let's start with Exhibit 1 and have you identify it and help us understand the information you've put on that display, and then let me ask you some questions about it.

A. Okay, this is a base map of the field, the Cabin Lake-Delaware Pool. The field is located in Townships 21 and 22 South, Range 30 East, in Eddy County, New Mexico.

The Phillips-operated lands are shown in yellow, the pool boundary is shown in an outline in red, and in the southern portion of Section 11, you'll notice drill locations N, O and P. That is the location of the proposed horizontal well.

Q. That's its nonstandard spacing unit, those 40-acre tracts?

A. That is correct.

Q. Let's leave that for a moment and have you tell us in summary fashion the history of development in the pool.

A. Okay. As I mentioned a moment ago, the discovery well was the James A 2, which is located in Section 2, in the southeast quarter. That well was drilled in 1988, and as I mentioned a moment ago, we drilled and completed in the Cherry Canyon zone.

And I should add, when I say Cherry Canyon zone, that is the interval that we will be talking about relative to the horizontal well.

Subsequent to that time, we have drilled -- I believe it's 28 or 28 wells. And that brings us on up into the present time.

Now, most of the wells were -- Well, all of the wells, with the exception of one other, were drilled through the Brushy Canyon. Those wells were perforated in the Brushy Canyon, the deep pay at 7000 feet.

And it's only in the last two years that we've begun moving uphole with the depletion of the Brushy Canyon or with lower production rates, anyway, from the Brushy Canyon. In the past couple of years, we've started moving up, back into, or into this Cherry Canyon interval that is real productive.

And so now we are at a point in time where essentially all of our drillable locations have been drilled, with the exception of these three locations, N, O and P.

Q. What is the significance to you of the -- I guess it's turquoise, the colored line that's identified as a potash line? What's the significance to you of that line?

A. The potash line as shown on here is our best approximation of where the potash line is. In Section 11, south of which would be the measured potash, that would coincide with areas where surface locations would not be granted.

Where we know or have a real good handle on where this line exists, in fact, is right there in location P in the southern portion of Section 11. When this well, the James E 9, was first brought forward, we attempted to establish an orthodox location and drill the well vertically. That would --

Q. For the -- Which spacing unit, Mr. Schramko?

A. Drill location P. That well would have been located 330 feet from the east line and 990 from the south line, and --

Q. Did Phillips, to your knowledge, attempt to permit that standard vertical location in unit letter P?

A. Yes, they did.

Q. And with whom would they seek permit approval?

A. The BLM.

Q. And with what result in this case?

A. It was denied.

Q. What then did you do?

A. Following that, we went through several gyrations with the BLM, attempting to establish where we could position the well, with our thoughts at that time still being, we might drill it vertically.

And what we found was, we attempted to move the well north and then we tried to move it east, and we found out that the only place open to us that was of use is that wedge shown in the northeast corner of drill location P in Section 11.

Q. Do you know whether that potash constraint or limitation applies to unit letter N and unit letter O?

A. We have made no applications on those properties, but we do have a well -- If you'll notice where the words "potash line" are written on here, and then the green line that comes down and touches, I guess, it would be drill location K.

And drill location K, we had a well, the James E 7. It's not shown on this map, because we never drilled it. We ran into -- In applying for a location at that location, we were denied. So we know that the potash line extends that far north.

So we're -- In summary, we're quite confident that we know where the potash line exists through this area.

Q. Having been unable to obtain a vertical location at a standard position in unit letter P, what did you decide to do?

A. Our first thought was, well, we know we have reserves there, let's go ahead and -- well, these were just internal discussions we had amongst ourselves.

Our first thoughts were, well, I guess we'll have to drill a deviated wellbore.

And during the course of these discussions, we realized that we had a continuing problem with drill locations O and N. We're confident there are reserves there.

I have run economics on drilling deviated wells, starting up around Well Number 6 in Section 11, and drilling to the south a deviated well and completing it vertically in drill location O. That's an uneconomic venture for us, as would drilling a deviated vertical well in drill location N. Both of those are uneconomic prospects.

So we were -- At the conclusion, we only had one location left and that would be drill location P.

And shortly thereafter, we looked at the information, and I came to the conclusion, well, we've got one zone here that is a real strong contributor; that's this Cherry Canyon zone. Why not drill it horizontally? And here we are today.

Q. Let's turn to Exhibit Number 2. Identify that display for us.

A. Exhibit 2 is simply a blow-up of the southern portion of Section 11, highlighting drill locations N, O and P, and providing the exact locations of the horizontal well, along with the various distances that are pertinent to the various boundaries.

The items of most significance are that the horizontal section, which is shown as segment B to C, honors the 330 setbacks, and therefore remains within the drilling/producing window as we're describing it.

Q. Is this the same display that you presented to Examiner Catanach?

A. Yes, it's identical.

Q. What's the significance of the red line?

A. The red line being the horizontal well.

Q. That is the anticipated or at least initial projected path of the --

A. That's correct.

Q. -- horizontal well?

That's it's approximate length and azimuth?

A. Yes.

Q. All right. Now, what is the purpose, then, of the drilling window, if you will, that is set back 330 from each of the side boundaries of the spacing unit?

A. Well, what we're asking is that the well not -- We can't possibly drill a horizontal well exactly along the red line as shown. We will have to make adjustments along the way. So we would want to insure that the order gave us the comfort we would need and the flexibility so that as long as we honor the 330 setbacks we wouldn't be in violation of any rule.

Q. All right, sir. Did the Division Examiner approve this concept plan for the horizontal well?

A. Yes.

Q. Let's turn now to Exhibit Number 3. Identify and describe that display.

A. Okay, this is a well plan of the well.

In summary, the well would be drilled vertically to the kickoff point at a depth of 5124 feet. The curved portion of the well would be drilled with a build angle of 12 degrees per hundred feet, which would bring us to a TVD depth at which we would be horizontal at 5768 feet.

At that point we would set and cement 7-inch casing, and we would proceed to drill the horizontal well approximately 2166 feet.

I should add that all of the cementing and casing would be done in compliance with Rule R-111-P.

Q. All right, sir. Let's turn to Exhibit 4. What is this exhibit, Mr. Schramko?

A. Exhibit 4 is a two-inch neutron density log from well James E Number 8.

Q. How is this of any importance to us?

A. Well, the James E 8 is located due north of drill location P, so it is our nearest offset control. I'm using it here as a type log, if there are any questions regarding the actual formation that we'll be drilling into.

Q. So the record is clear about the footage location on the log, which corresponds to the Cherry Canyon member of the Delaware that we're seeking to access with this well, could you identify that portion on the log for us?

A. Yes. If you'll go down through the log, starting at the top, you'll notice various depths have been marked in the margin, and you'll notice that the Cherry Canyon top is at 4510 feet.

The Cherry Canyon -- well, the -- I've labeled it as the top of the Brushy, which is at 5904. That is also coincidental, then, with the bottom of the Cherry Canyon.

For clarification, the Delaware is broken up into three main intervals, each of approximately 1000 feet. The Cherry Canyon, then, is between 4500 feet and 5900, and the interval that we're targeting is at the very deepest part of the Cherry Canyon at 5768 TVD.

Q. As part of your engineering study of the feasibility of the horizontal well, did you ask the personnel at Phillips that had specialty in geologic matters to assist you in any way?

A. Yes.

Q. As a result of that assistance, did they provide you with any geologic interpretations with regards to the position, size, shape of this sand member of the Delaware?

A. Yes, they did.

Q. Have you examined that information?

A. Yes.

Q. Did you incorporate it and utilize it in your engineering analysis about the feasibility of the well?

A. Yes.

Q. Describe for us what you used.

A. The next two exhibits, Exhibit 5 and Exhibit 6 are geologic maps provided by our geologist.

Q. Let's look at Exhibit 5 and have you -- Exhibit 5, what is it, sir?

A. Exhibit 5 is a structure map of the Cherry Canyon, the target interval.

Q. In what way did you utilize this in your work?

A. Our knowledge of this particular formation suggests that we want to be as high structurally as we can. There is bottom water, there is a water-oil contact, and it is beneficial to be near the top of the structure, to be away from the water.

Q. What then did you do about the direction of drilling the horizontal well in view of this structural component of the reservoir?

A. Well, in terms of a horizontal well, there was really no other way to orient the well.

But as we look at the structure as it traverses across drill locations N, O and P, you'll note that the well stays near the top of the structure. Basically, there's an anticline here with falloff to the east and the west, and there's a fairway that runs in a northerly-southerly direction, and N, O and P will encounter that high.

Q. The severe surface limitation placed upon the well by the BLM for its location in the northeast corner of P allowed you to access the reservoir in such a way that is consistent with structure --

A. Yes.

Q. -- and how you would want to access the structure?

A. That is correct.

Q. Let's turn now to the next map. It's the isopach.

A. This is a gross sand thickness of the same target, Cherry Canyon interval, and it's in some ways showing similar information.

Basically, you'll notice that the pay thickness for the wells just north -- It ranges around 100 to 125 feet of gross thickness, so we -- By the contouring, we fully expect drill locations N, O and P to encounter similar types of reserves to what we've seen in some of our better Cherry Canyon wells.

Q. Have you made any engineering assessments or calculations with regards to your expectation of the original oil in place that underlies these three 40-acre tracts?

A. Yes.

Q. What is your conclusion about the oil in place underneath those tracts --

A. We --

Q. -- in this member of the Delaware?

A. We have calculated the oil in place on each 40-acre tract to be approximately 1 million barrels. So for the three tracts here, we'd be talking about a 3-million-barrel oil in place.

Q. Based upon your experience in this reservoir, do you have an estimate of the percentage of that oil in place that is recoverable?

A. Yes, approximately 25 percent.

Q. What's your anticipated total volume of recoverable oil if this well is successful? Do you have a range for us?

A. Horizontal.

Q. The horizontal well.

A. Our best approximation is 650,000 barrels of oil.

Q. All right, sir. Let's turn to Exhibit Number 7. Identify the plot for us. What we are looking at?

A. Okay, we're now ready to start talking about the performance of a horizontal well, and that begins by discussing performance of a typical vertical well.

And what we have here is a production plot for the James E Number 11. The black data on this plot is the daily oil production rate, and the red data is the cumulative oil versus time.

Q. All right. If you'll take Exhibit 1, find us the location of this James E -- I'm sorry, what was the number?

A. Number 11.

Q. The Number 11 well.

A. It's in drill location D of Section 12. It's the northwest quarter of the northwest quarter.

Q. Why did you select this vertical well as an example of the performance of a vertical well to show the Commission?

A. Only because it shows the -- better than some of the other wells, it shows the initial production rate that we typically see, and it also shows the standard decline that we see.

As I mentioned earlier in my testimony, in the last couple of years we have been recompleting wells to this Cherry Canyon, so in some cases we don't have a lot of data; I wouldn't have been in a good position to show you the standard decline that we're seeing. This well shows it.

Q. To what purpose did you put this information?

A. Okay, basically what we wanted to show was that a typical vertical well will initially produce at rates of approximately 200 barrels per day. We even have wells that will IP at 300 barrels a day. But this is the range of what we expect, 200 to 300 barrels a day from a vertical well.

You can see from the decline -- The black X's are the production decline that we expect.

Of most significance here, and the purpose for this exhibit, is to show you that the red X's out in 1999 will reach 200,000 barrels of oil recovery.

That is our expectation of a vertical well, to summarize, 200,000 barrels per well.

Q. What's the drive mechanism in the reservoir, Mr. Schramko?

A. Solution gas drive.

Q. No concern on your part about disproportionate gas withdrawals? The reservoir is not rate-sensitive as to gas withdrawals?

A. That's correct.

Q. As part of your analysis, did you come to any engineering conclusion about he potential drainage effects between your proposed horizontal well and a typical vertical well?

A. Ask me that one more time. The difference between -- ?

Q. Yes, sir. Did you, as part of your engineering study, make any engineering calculations or reach any engineering conclusions about the drainage effect of a vertical well versus a horizontal well?

A. Oh, okay. Oh, yes. Yes, I reviewed that, and I think what you're asking me is, would I expect a horizontal well to behave any differently than a vertical well, or could we say three vertical wells?

Q. In terms of the distance in which they access and deplete the reservoir?

A. Yes, I've made an assessment of that, and a horizontal well will not behave any differently than vertical wells.

Q. Did you make an engineering assessment or reach any engineering conclusions about the estimated ultimate recovery from a horizontal well, versus three vertical wells, if each of these spacing units was to receive its own vertical well?

A. Yes, I did.

Q. And what conclusion did you reach?

A. Basically that a horizontal well is going to recover the same amount of oil, the same volume, as would three vertical wells.

Q. Did you recommend to the Examiner a special project daily oil allowable for the horizontal well?

A. Yes.

Q. And what was that recommendation?

A. That it be equal to 187 barrels a day times the number of drill tracts contacted by the horizontal well.

Q. And what action did the Examiner take on that request?

A. He granted that.

Q. Part of the Application dealt with your request for a special test period?

A. Yes.

Q. What was the test period requested by you to the Examiner?

A. We were asking for the ability to produce the well -- for a moment I'll say at capacity rates for one year, allow the well to decline, and at the end of one year any accumulated overproduction would be made up during the second year, either by shutting the well in or by reducing production below the daily allowable limit, so that at the end of 24 months overproduction would be zero.

Q. What was your engineering reason to request the test for this well?

A. So that we could perform rate-time analysis, which would take us down the path of being able to quantify the damage and the permeability in the well and make estimations or determinations as to whether we should stimulate the well.

Q. What is the engineering concept that you identified as a rate-time analysis? What is that?

A. Rate-time analysis is type-curve matching. It is stated in many ways. It is decline-curve analysis, done with type curves. It is a process of plotting your production data on log log paper, overlying it on appropriate type curves, type curve, the appropriate type curve, obtaining a match and then calculating the permeability of the skin.

Q. What if any experience have you had as a reservoir engineer with conducting those type of tests, analyzing the data and reaching engineering conclusions?

A. Before I answer my experience, I'd like to say that Phillips Petroleum is generally regarded as the industry leader in rate-time analysis, primarily through the efforts of one employee that we've had, Mike Fetkovitch, who is regarded -- I think this would go unchallenged -- as the number-one industry individual in rate-time analysis.

I have had the luxury of working for that man for four years, and during that time I worked almost exclusively on rate-time analysis projects.

Q. Can you use the horizontal well within the limitations of the special 561-barrel-a-day oil allowable and achieve or obtain reservoir data by which to conduct accurate rate-time analysis?

A. No.

Q. Why not?

A. One of the requirements of rate-time analysis -- and for the sake of what I'm about to say, I want to change the name. Let's call it decline-curve analysis for a moment.

One of the requirements of decline-curve analysis is that the production rate must decline. Therefore, if the well has the capacity to produce at 1000 barrels a day or 1600 barrels a day, but we hold it back to 561, that means that there is going to be a constant rate period -- maybe six months, eight, ten, twelve months -- and all I'll have is that constant rate period. I can't perform decline-curve analysis or rate-time analysis on wells that don't decline.

Q. If you're unable to do that kind of analysis on this test and are required to stay within the limits of the 561 oil allowable on a daily basis, you can't run the test, what's the problem?

A. The problem is, the only tool -- well, it's not even a tool. The only thing I would do -- Of course, my job would still be to evaluate this well.

I would monitor the production of this well, and I'd be watching it until the day it began to decline. Let's say for the sake of discussion that's in the 12th, 13th month.

The only thing I can do at that point is to go into the models that I've used and that I'll be discussing in a moment and attempt to match what I'm seeing.

And the problem, as I'll be showing in a moment, is, there are, in effect, an infinite number of combinations that could match behavior on a well such as that.

At the extremes, I want to know, is the well damaged, or is it not damaged?

And what I'll be showing you in a moment is, I can't distinguish between those two. When that well declines in the 13th month, the character of a damaged and an undamaged well will look very similar, so similar that I can't distinguish between the two.

Q. So what does that mean to you as an engineer?

A. It means I'm put in a position of trying to answer the question, should we or should we not stimulate this well, without the knowledge of knowing that it is damaged.

Q. When you talk about a damaged well, what are you saying?

A. During the drilling process, the fluids have invaded the formation and caused a skin on the actual reservoir itself that's limiting the flow into the wellbore.

Q. And if you are able to recognize that the low productivity of your well or a decline in production is directly attributable to the skin damage, what then could you do to correct that fact?

A. We can go in and acidize.

Q. What happens if the low productivity is not contributed by -- not the result of skin damage, but simply the result of low permeability?

A. Then you're describing a situation where the well is not damaged. And what we would have -- If you make the assumption that we go in and stimulate that well anyway, then you've put at risk the well by pushing coiled tubing out into the horizontal section, for whatever risk that imparts on the well, you've acidized the well, you've spent capital for nothing, because we've -- as your condition stated, the well isn't damaged, so we would get nothing for that. But we have put the well at risk.

Q. Based upon your engineering experience, is there any alternative method that you can utilize in the absence of the rate-time analysis?

A. The alternative, the standard alternative that is used in the industry, is the drawdown-buildup test.

It has been my conclusion, and everyone in Phillips is agreeing with me, that we are not going to run a drawdown-buildup test, regardless of the outcome of this hearing, primarily because this well is going to be run on artificial lift.

We're going to have a submersible in the bottom. And getting tools in and out of a well, conducting the test, is very difficult. Obtaining the data is difficult.

So we have no intentions of running the drawdown-buildup test. We will attempt to use whatever other techniques are available to us.

Q. In the absence of approval by the Commission to conduct the test, do you have an assessment or an engineering opinion about the magnitude of recoverable oil that may be at risk in the absence of an approval?

A. Yes, 100,000 barrels.

Q. Your original proposal was to run the test for a twelve-month period?

A. That's true.

Q. What was the reason for utilizing twelve months and then to make it up in the subsequent twelve months?

A. There's no magical answer as to how long one needs to run rate-time analysis. The answer is determined when you have gotten a substantial number of data points, you've plotted them on log log and you've overlaid them on a type curve, and you can make your engineering assessment that, yes, I've got enough data. I can't tell you exactly if that's twelve months, nine months or fifteen months. There's no magical answer.

But we can make some qualitative statements. The fewer data points I have -- Well, let me start another way.

If I only have one data point, one month, that, of course, isn't -- I can't match that.

If I have two data points, that establishes a straight line; I can't match that.

With a third data point, you're starting to get there. But again, it wouldn't be a unique match.

I'm going to have to have upwards of at least four or five data points to conduct -- to obtain the data to make the match.

The other qualitative factor that I was starting to talk about is, you run into production problems in the field, the electricity shuts down, your submersible is knocked out of operation for several weeks.

So any given month -- and this is a real event out there with the shutdown of electricity -- any given month can be wiped out as a good data point.

So out of twelve months, you might lose two or three data points because of production problems. You could lose a couple more related to a tank battery. There's just no real right/wrong answer here.

But I'm being asked to determine how many do I need, and when we first came forward to the Examiner we felt like twelve was a good number to ask for.

Q. Let's go back to the modeling. If you'll turn to Exhibit 8 and let's talk about the modeling aspects of your engineering study. First, show us what you have presented on Exhibit 8.

A. Okay, Exhibit 8 is simply the list of input parameters for one of three models that we used to obtain the expectations of the well. I won't review them in any detail, but they are here for -- if there are any questions regarding that input.

Q. Describe for us the type of model you selected to use.

A. That's a -- Well, as I stated a moment ago, there were three models that we ran. This one is the DEA-44 model. It's an out-of-house model that was created by Maurer Engineering as an industry-concerted effort. Some hundred companies went together, brought their -- pooled their capital and had this model created by Maurer Engineering.

Your question is, What type of model is it? It's a single-cell tank model, is how it would be generally referred to in the industry.

Q. Is a single-cell tank model suitable and appropriate for the type of analysis that you're attempting to undertake for the rate-time study?

A. Yes, it is. We're trying to show a reasonable expectation. That is one of the uses of a single-cell tank model.

Q. Is it necessary to go to any more complicated or sophisticated model?

A. No.

Q. Why not?

A. The absence of data. As we go to the southern portions of our field, there is no well control to the south of Wells 8, so we would have no way to describe the reservoir in any meaningful way, so that whether we gridded it finely, gridded it big -- However we would grid it, would be of inconsequential -- What would be important is what permeabilities you decide to put in there.

What we're comparing it to here is a 3-D model simulation. The statements I'm making are, a 3-D model can only be as good as the data that's put into it. In this case there would be little data, so we're stuck with a single-cell model.

Q. But that's an appropriate model for use in this purpose?

A. That's correct. As I stated, what we were using the model for was reasonable expectations, what could we reasonably think this well might do?

Q. When you're dealing in that engineering concept, are you not dealing with simply a single-flow equation, if you will?

A. That's correct.

Q. And so you don't need any more sophisticated model than the single-cell model?

A. That's right.

Q. Okay. Let's look at Exhibit 9. What does this represent?

A. Exhibit 9 is simply five pages out of the DEA-44 Manual. It provides background assumptions to what's in that model, and it's only provided here as background if there are any questions regarding that model.

Q. Let's turn to Exhibit 10. You've indicated production forecasts from three reservoir models.

A. That's correct.

Q. What are you attempting to forecast?

A. The expectations of a horizontal well.

Q. All right. You're taking the input parameters; the forecast is to see what happens for this horizontal well?

A. That's correct.

Q. You've run the forecast through nine years, is it?

A. Yes.

Q. And that is the vertical scale?

A. Yes, that's correct.

Q. As we move horizontally from left to right, the DEA-44 model, what do those numbers represent?

A. If I could back up for just one second.

Prior to running the model horizontally, the first step in any of these models is to try to model a vertical well. Can I get this model to ensure that it will tell me what a vertical well can do?

Each of these has a switch, that once I've modeled the vertical, throw the switch to find the horizontal parameters through the reservoir, and it gives me a horizontal well forecast.

So the first step here was to model the vertical well.

A while back I told you that -- and showed you an exhibit that said that a typical vertical well will produce 200,000 barrels of oil.

So the first step was to define my parameters. I input what we felt were basic flow parameters for this reservoir, and within -- There was no tweaking of the data. Essentially, I had a match from moment one. I had to adjust the permeability from .4 -- no, .3 to .2, and we had our match.

Q. What are you matching?

A. The production history.

Q. Of the vertical well?

A. That's correct.

Q. And which vertical wells did you use for your history match?

A. Essentially, they're all within a certain fairway in there. There are seven or eight wells that are all producing with very similar rates, 200 barrels a day, and we've got their reserves estimated at 200,000 to 250,000 barrels of oil.

So I wasn't really history matching each data point; I was looking primarily for initial production rates and ultimate recovery.

Q. Were you able to successfully history match all three models on vertical wells?

A. Well, I should probably, before I answer that, define the three models, because one of them is only a vertical model.

Q. All right, sir, let's do that.

A. Okay. The first model, as I've already described, is the DEA-44 model. As I said a moment ago, that's an out-of-house model done by Maurer Engineering. It has the ability to run a case for modeling a vertical well, throw the switch and run it horizontal.

The second model, the forecast shown on Exhibit 10 here, is a Phillips in-house model, very similar in its design to the Maurer Engineering model. It's a horizontal model. You can model vertically and then model horizontally as well.

The third model is a tad unique. It is also a Phillips in-house model, but it's one that only models a vertical well. However, through our efforts at Phillips we have shown that a horizontal well can be equated to a vertical well with very large negative skin.

Said another way, equated to a vertical well with a very large frac job.

We can go through a mathematical manipulation to take 2166 feet of horizontal length, convert that to a skin which is equivalent to the vertical types of skin we're used to.

In this case, that calculation came out to minus 6. If you're familiar with rate-time analysis, that would be equivalent to a very large frac job.

So once that was done, then all we do is model the well, after this conversion, if you will, as a vertical well. And so the third column that you're looking at, is that vertical model.

It was just another way of looking at the problem. I wanted to investigate all three for consistency, because I knew all those thicknesses are available to me, so we did that.

Q. With what result, Mr. Schramko?

A. Well, I guess I started to answer my own question. The results were very consistent.

Q. And what did they tell you?

A. At the bottom of Exhibit 10, we're seeing ultimate recoveries ranging from 628 to 661.

In fact, if I might make a note here, I just noticed something of a mistake in my exhibit.

At the bottom of Exhibit 10, where I say "Ultimate Recovery (MBO)", does everybody see that? At the bottom of the exhibit where I list ultimate recovery for each --

Q. You're short an "M"?

A. No, that's correct --

Q. Is that correct?

A. -- but you'll also notice I labeled each of the individual columns as "BOPD". That "BOPD" should be scratched. I just --

Q. Yeah, we're talking about ultimate recovery.

A. It's ultimate recovery, MBOs.

So the answer to the question is, the well should produce approximately 650,000 barrels of oil. That's a reasonable expectation.

Q. How does that compare to what you would expect to ultimately recover if you had the ability to drill three vertical wells, one in each of the three spacing units?

A. Well, it's almost exact. As I stated, a typical vertical well would do 200,000 barrels, plus or minus. So if you added three of those up, you would have 600,000. I'm calling them the same. So you'd recover 600,000 total barrels if you had three vertical wells.

Q. Do you have any opinion as to whether there's inherently any production advantage, then, to the horizontal well in terms of total recovery, versus the three vertical wells?

A. I would expect it to be the same.

There was one other point I failed to make, and that is that -- rules of thumb in the industry. If I gave you no information at all about a horizontal well except to tell you what a vertical well would do, 200,000 barrels, the experts in the industry, in the horizontal world, would tell you, expect 2 1/2 times a vertical well for ultimate recovery.

So I sort of had that knowledge also that we're in order here. Two and a half times a 200,000-barrel well would be 500,000 barrels, rule of thumb.

And so, again, I'm just leading up to the consistency. To me, this all ties together in what we would -- should reasonably expect from the well.

Q. Let's turn now to the details of the rate-time process.

If you'll look at Exhibit 11, describe for us the engineering significance of this type curve that you've shown.

A. Okay, Exhibit 11 represents a family of type curves, and on each of your exhibits there is one curve on there that is highlighted in yellow.

Through a sequence of computations relative to the length of this horizontal well, the height, the wellbore radius, you can define which of the curves on here is the one I would be using. Having gone through that, the curve we can talk about is the one highlighted in yellow.

What that means is, the horizontal well that we're describing should traverse along the path of the curve that's highlighted in yellow.

Q. All right, sir. What purpose do then you utilize that?

A. Well, once the production data has been obtained, we would be plotting it on log log paper. We would be attempting to overlay it on this type curve in an attempt to obtain a unique match.

Once that match is obtained, we can select a match point from anywhere, and using the equations shown at the upper right -- t_D equals some stuff there, and q_D equals some stuff, in the upper right -- we can calculate the permeability and the effect of length, which is, in effect, the skin damage.

So this is the rate-time process that I once again went through.

Q. When we look at the application of the rate-time process to the James E 9 horizontal well, under the assumption that the Division approves the special test period so that you can have additional rate early in the life of the well, do you have an illustration that sets forth that example?

If you look at Exhibit 12, can we not --

A. Yes, I --

Q. -- utilize that display --

A. Sure.

Q. -- for that --

A. Sure.

Q. -- purpose?

A. I wasn't sure I understood your question, but I know where you're going.

Exhibit 12 shows us two behaviors from wells that are represented identically, with two exceptions.

One of these, the red curve, represents a well that has lower perm but is undamaged.

The blue curve represents the same well with slightly higher perm, but it's damaged.

We can talk about the quantification of rate-time analysis in great detail. But qualitatively, what we're after in rate-time analysis is the ability to distinguish between two curves, those two curves. The red one is an undamaged well, the blue one is a damaged well. I need to be able to distinguish between those two.

This exhibit is showing you that the undamaged well should experience a steeper decline than the undamaged well.

I'd now like to go on to the next exhibit.

Q. All right, let's put them side by side so that we can see the comparison.

When you look at Exhibit 13 --

A. These are the same two wells. But, because we were unable to produce the well at these wide-open rates, we are artificially, then, we'll say, constrained by the allowable of 561. Both of these wells would produce for nine months at that constant rate.

In the tenth month they would both begin to decline, identically. In the eleventh month they both decline, again identically. In the first year there, you'll notice that the two curves begin to separate.

In the absence of a special test period, this is the type of data that I would have. I would be asked, Is this well damaged or undamaged? And I'm saying that I can't distinguish that red curve and blue curve.

The differences between them out in the second year are approximately 50 barrels a day, and since we know real field data isn't going to be nice and exact, it's going to have erratic ups and downs in it, I'm not going to be able to distinguish between those two at all.

So let me back up again to Exhibit 12.

I have the ability, if the special test period is granted, to distinguish between a damaged and an undamaged well.

Q. Show me using Exhibit 12 an illustration of the data points that you would have available if you were granted approval for a twelve-month test.

A. Okay. Using Exhibit 12, let's talk about the red curve, and in the first month of production, the well produces -- oh, that looks to be about 1275 barrels a day, something just under 1300 barrels a day.

At the end of one year that well would have declined to a rate of approximately 350 barrels a day. And of course I would have twelve data points, ten in between those two, describing the character of the well.

Q. Would that be sufficient data points for you as an engineer with your expertise in this area, then, to have a clear indication of whether you were looking at a well that had high permeability and no damage, versus a low-permeability well that was undamaged?

A. Most definitely. When we first started this -- Again, when we requested twelve months, I looked at that and I said, you know, after twelve months the curve is starting to smooth out. Much beyond one year -- If I can't get it in the first year, I don't have it, I don't have my match.

As you know, we've altered our request for six months, and the thing that I went back and looked at was, the real character was defined within the first six months. Once you've nailed it down, you can see the first three months really put you in line. That character is defined by the first six months.

So realistically, we can perform this test in six months if all production equipment will cooperate and we can collect the data, which we fully expect we should.

Q. Did Bass employees express to Phillips employees their concern about the twelve-month test period?

A. Well, maybe some history is in order.

I have been trying for about four weeks -- Let me back up even a tad further.

Since the inception of this special test period, the thought which I created -- I honestly felt like I didn't understand their objection. I never expected an objection, because if they are to drill a well south of us, then they would find great use in this data.

So following the results of the last Examiner hearing, I tried immediately or shortly thereafter to get ahold of Bass, find out what their concerns were, what -- Let's talk about this.

I went over to their office, met with three of their engineers and their landman, Wayne Bailey, and I explained using these same exhibits what our intentions were. And I asked them, What concerns do you have, what problems do you have?

I never got what I would call any real feedback to tell me what their concerns were. In roundabout ways they talked about drainage, they talked about -- that,

that's about it.

I was asking -- The specific question I was asking, is there something we can do to this special test that would really address the concerns you have?

So I was trying for four weeks, right on up until I caught my plane to come up here, to find out what their concerns were.

I'm still not sure, other than I know that they seem to have expressed that if we cut the test to six months, made up the overproduction within six months, that that would be satisfactory to them.

Q. Have you examined whether or not you could achieve sufficient information -- If you reduced the test period to six months, would you still have useful data by which you could make judgments about the well?

A. Yes.

I want to go one step further and say that if the test was to be reduced much less than six months, you're getting into the point where, yes, we might be able to conduct the test, but now you're into limiting the data points to such a few number that probably in the end I'd be unable to analyze it.

Again, the production data -- This is computer-generated data. Real data has ups and downs and spikes. You've got to be cognizant of those, know how to account for that spiky behavior, and have enough data points so that that spiky behavior can be seen through, so that you can see trends and what's actually going on.

Six months is reasonable. We can live with that and conduct a test.

Q. Turn now to Exhibit Number 14. Identify that display for us.

A. Exhibit 14 addresses the flow velocity of fluids in the reservoir, and it's our way of showing that a horizontal well would not damage this reservoir.

Q. How does this tell you that?

A. Basically by addressing fluid velocity.

The elements that cause damage in a reservoir are related to the flow movement, the movement of fluids through that reservoir. The higher the rate of withdrawal, the more likely you are to cause fine migration, cause coning of water, gas, if that's an issue.

The issues that drive damage in a reservoir, that we're trying to address in terms of could a horizontal hurt this?, are related to fluid velocity.

So we're using fluid velocity here to show you that in fact, jumping to the answer, the fluid velocity in this horizontal well would be seven times less than, or 6.8 times less than, the flow velocity in a vertical well.

The movement of fluids in this horizontal well are seven times less than in a vertical well, and therefore less damaging.

Perhaps I should -- Should I go through the specifics?

Q. No, sir, I think that's sufficient. Let's go on to Exhibit Number 15.

And before we talk about it specifically, one of the issues at the Examiner hearing was an attempt to illustrate the potential recoverable oil that was at risk in the absence of approval of the test.

Subsequent to that hearing, have you re-investigated that concern?

A. Yes, I have.

Q. Have you attempted to quantify the potential magnitude of recoverable oil that might be unrecovered if the test period is not approved?

A. Yes, I have.

Q. In terms of that analysis, have you arranged your conclusions in the form of an illustrative display?

A. Yes.

Q. And that's Exhibit Number 15?

A. (Nods)

Q. All right. There's a larger copy of that, and let me display that.

A. Tom, I wonder, could we move it over here? I was going to use a pointer.

Or I can work from there, I guess. It's probably not --

Q. Let's try it over there by you and see if --

A. Either way it will work, I think.

Q. -- see if that blocks anybody's view.

A. I'm going to be talking about the various blocks, and so I was going to use --

Q. All right, let's try it this way.

A. Yeah, I think that will work.

Q. Do you have a pointer?

A. Sure. Okay, this exhibit is put together to show you that there are some conditions out there where this test period could result in the recovery of 100,000 barrels of additional oil, and I want to direct your eyes first to the top right side where I'm outlining those conditions.

Q. It's captioned "Specific Analysis of Horizontal Wells"?

A. That's correct.

Q. The first condition assumes what, sir?

A. That as we outline, we will drill the 2166-foot horizontal well.

Q. With the expectation of what forecasted recoverable reserves?

A. 628,000 barrels of oil.

Q. If that wellbore experiences some skin damage that you might otherwise correct if you knew, have you made an assessment of what might be the effective length of that producing wellbore? Even though it might be 2166 feet long, what would be its true effective length?

A. Of course, I could have made several selections along here. The one that I chose is a condition where the last 466 feet of the well, leaving 1700 feet of the well open, the last 466 feet is so damaged it's noncontributing at all. So that in effect I have a 1700-foot horizontal well.

Q. Is there a reasonable engineering probability that that could actually happen?

A. Yes, that's quite reasonable.

Q. And what would be the result, then, of that occurrence for this well in terms of its recoverable oil?

A. The result would be a shrinkage of the drainage area. It's easiest to visualize if you picture it as the tip or the initial 466 feet.

If I've drilled the well out there, I expect the tip to contribute oil from the tip. If in fact, the last 466 feet is not contributing, that means that my effective tip is only 1700 feet long, and so there's oil out beyond the horizontal well that I would not drain.

When I put this condition into the model and asked it to predict how much recovery, the number was 526,000 barrels of oil.

Q. So under this example, how much recoverable oil is at risk if in fact there's skin-damaged horizontal wellbore?

A. The difference between those two, 102,000, actually. I labeled it as 100,000 to round it off.

Q. As an engineer with expertise in this area, let's have you give us a summary of how you would go about analyzing this wellbore under the various risk components of doing this work, with the test data information and, in the alternative, without the test information. Have you analyzed it in that fashion?

A. Yes, I have.

Q. Describe for us, without reading this entire table, how you went through the process.

A. What I first want to say is that this is a quantification of a thought process.

If I stand before you and say I wouldn't stimulate an undamaged well, you have good reason to put that statement and quiz me on that. How did I come to that assessment? Why wouldn't I stimulate an undamaged well? We do it all the time in vertical wells. We don't know it's damaged; it's part of our typical completion in a vertical well, stimulate it.

So now we're talking about a horizontal well, and I'm going to say, I'm not going to stimulate this well unless it is -- unless I know it is damaged.

What these numbers show throughout here where you're looking at probabilities, wellbore conditions, what's going on, is the quantification of that thought process that helps me to arrive at the conclusion that I wouldn't stimulate the well unless I know it's damaged.

Starting in the left side where it's titled, "General Risk Analysis of Stimulations", all this is doing is outlining several wellbore conditions, identifying the possible outcomes and assigning a probability to what could happen following a stimulation.

I've made a distinction between early in the life, versus later in the life. The ideal time to stimulate a well is early in its life when you've got all the reservoir pressure you might have working for you to clean the fluids out.

It's particularly significant in a horizontal well. The point being that the probability of success, of removing damage, is improved if I do it early in its life, as opposed to a year or two or three years down the road.

The probabilities that are shown under the General Risk Analysis of Stimulations are then applied to the two situations that I might have: one, the test period center is granted. And that issue is addressed in the lower portion, if the test period is granted.

And I've also applied these same probabilities to what happens if the test period is not granted, shown in the lower right corner.

The answer that I'm attempting to arrive at as an engineer is the risk assessment of what all can happen, and that's the purpose of these probabilities. We might get complete removal of damage, partial removal, we might do nothing, we might damage the well. And there's this one other item that hangs out there: We might actually lose the well.

So we have a well that has this effective length of 1700 feet, and I don't know it.

The strange thing is, that well with its effective length of 1700 feet will come on at good rates. They'll be strong, so strong that this well will produce at the 561-barrel-a-day allowable for quite some time before declining.

Q. Let me ask you something about the rate. What is the practice of Phillips in the pool with regards to how high you flow the well?

A. The allowable, is that -- ?

Q. Yes, sir. Separate the allowable. Forget the allowable.

Is there any risk in the reservoir or to the wells if they're produced at capacity?

A. No.

Q. When you say wide open, you're talking about capacity?

A. Yes.

Q. Can you give us a range of choke settings? What do you do in the field when you put a well on wide open?

A. Well, when you talk about existing wells, we're talking about wells on pump jacks. So wide open would simply mean keep the pump jack running 24 hours a day, maximizing the stroke length and things of that sort, pulling out the maximum amount of oil.

Q. For this example, what you're looking at is the horizontal well as a flowing well?

A. No, this is -- We'll have a submersible in the well. So this condition would be putting the submersible in the well, turning the well on, allowing the submersible to remove the fluids and leave the well alone.

The way to deal with it if in fact the allowable is imposed and the well must honor that would be several choices: You can put in a smaller sub to begin with, or leave the larger sub in the well and shut it off, let it run eight hours a day. Those would be your choices.

Q. What's the basis for the maximum rate in your request of the 1683 barrels a day?

A. The basis is that that's our reasonable expectation of what the well might do. I don't under any stretch of the imagination believe the well could do any more than that.

Q. So that's the ceiling cap for the test period allowable on a daily basis?

A. Yes.

Q. Whatever that well will do, you want the opportunity to do it in the first six months?

A. Correct.

Q. And if by happenstance or otherwise it exceeds its allowable by the end of the six-month period, any overproduction is going to be balanced by the end of the second six-month period?

A. That is correct.

Q. All right. So based upon real-world experience with this wellbore, you're going to make the appropriate adjustments so that you balance at the end of the year?

A. That is correct.

Q. If that's approved, do you see any opportunity to violate the correlative rights of Bass?

A. No.

Q. When you're looking at the test period granted versus not granted and you've gone through your risk analysis as you've outlined it for us on Exhibit Number 15, what's the point -- When we get to the line in the block that says "Test Period is Granted", there's a risk benefit of 22,000 barrels; we get over into the other block, it's not granted, there's a negative number of 20,000 barrels. What significance is that to you as the engineer?

A. The significance is -- not so much the magnitude of the numbers, really, but the fact that one is positive and one is negative.

What it's in effect saying is that if the test period is granted and the condition that I talked about a moment ago, this effective length of 1700, is identified, and I know that's the condition, then I'm going to -- then there's only five conditions that can happen if I go and stimulate it, and I've listed there: I can get complete removal, partial removal, no change in the well's behavior, I can cause damage, or lose the well. Those five outcomes result in a positive incremental oil recovery, 22,000 barrels.

Conversely, if the test period is not granted, I end up with a negative number, basically because I'm going into what might be an undamaged well. That's really the only difference between these two cases.

In the case where the test period is not granted, I might be entering a well that's not requiring damage [*sic*], and in that case, the only outcome can be negative -- well, or no change.

So I could actually damage the well, and that can be caused by precipitation of acid in the formation, any number of reasons why, not to mention mechanical risks that you're putting on the well.

Again, putting coiled tubing out in the well, it's not a straightforward operation. We do it all the time, but it happens where you push it out there and it twists off and -- You can go so far as to say you could end up P-and-A'ing the well. Small likelihood of outcome. But when you multiply that small likelihood of outcome against a very big reserve number of 526,000 barrels, it adds up.

It's no different than if I said to somebody, You inherited a good well. Somebody comes along and says, Why don't you stimulate it, and it will be an excellent well? Well, you've already concluded in your mind it's an excellent well. You know in the back of your mind that, I'm happy with what I've got.

It's the old adage, Don't mess with a good thing. In this case you're saying, Don't even think about touching this good thing, because that well that I described, the 1700-foot effective length, that's a good well. 526,000 barrels of oil, we'd be happy with that.

I'm not saying Phillips is going to stand up and say that's a poor well. The fact is, there's still another 100,000 barrels that might be recovered. If we can identify it, we'll go in there and try to get it. If we can't identify it, we'll live with that well.

Q. Well, and the problem is that you may have made a mistake that you could otherwise avoid?

A. That's correct.

Q. Have you attempted to quantify the magnitude of oil produced under the test period to see what effect that has?

A. Yes.

Q. You've run a forecast of production, have you not?

A. Yes.

Q. Let's turn to that. It's Exhibit 16. Describe for us how you've organized or arranged the display, and then let me ask you some questions about the details.

A. Okay. What you're looking at here is a twelve-month production forecast, the first column being the same reasonable expectations I've been talking about throughout this hearing. I will say that that is the exact data shown, relative to the DEA-44 model output. They're one and the same, the difference being that earlier you were looking at an average daily rate over the first year; now you're looking at each of the monthly outputs.

So the first column is the actual production that we could expect from this well over a twelve-month period.

The second column is straightforward. It's labeled as the project allowable, 561.

The third column would be the monthly overproduction that would result if the well was produced at the rates that I described in the first column, honoring the allowable shown in the second column.

So in the first month of production, if the well is produced at 1600 barrels a day, with the project allowable of 561, that well at the end of month one would have 31,000 barrels of overproduction. The same for each of the subsequent months.

And in the last column you're simply looking at a cumulative number for each of the months. So by the end of the second month, we would have a cumulative overage of 57,000 barrels.

Q. If you go down to the end of the twelfth month and read to the far right column, the total magnitude of overproduction under this illustration is 147,000 barrels of oil?

A. That is correct.

Q. All right. And your plan was then to take the next twelve-month period and to make that up, if you will?

A. That's right.

Q. All right. If we draw the line and delete the last six months, take the test period back to a six-month period, what is the potential cumulative overproduction in barrels of oil?

A. 123,000 barrels.

Q. All right. And how would you propose to make that up?

A. The well would be shut in immediately. In fact, there is a slight -- In order for that well under these conditions to make up all the overage before the end of twelve months, it would have to actually be shut in before the sixth month.

Q. Well, and you would have the ability to do that as the engineer?

A. That's correct.

Q. All right. If it were less than that number, if for some reason the well didn't perform that well and it's not 123,000 barrels of oil, then you're seeking the second six-month period in which to balance it?

A. That's correct.

Q. So there may --

A. Under any condition.

Q. There may be an opportunity where you could continue to produce the well, taking the excess allowable, applying it to the overproduction so that you eventually balance?

A. Yes, there is a very likely outcome where if the well begins to initially produce at only 1000 barrels a day and then engages in its decline, that that well would be overproduced only 40,000 barrels at the end of the six-month period.

We're asking that instead of having to shut the well in, which can -- Let me say, in other words, you don't want to shut in good wells. You'd like to keep them producing, even if it's at a small volume.

What we're asking for is the flexibility as the operator -- We'll make it up, we just want to be able to do it ourselves, because I can't lay out every possible scenario.

If it's 40,000 barrels overproduced, one option, one logical option that we would probably select, is to produce the well at 40 percent of its capacity, something like -- or I should say 40 percent of its allowable, 200 barrels a day. If the well is 40,000 barrels overproduced, starting in the seventh month, if we produced at 200 barrels a day for the next six months, the overproduction at the end of the year would be zero.

Now, the alternative is to say to us, No, shut the well in. It's a possible outcome, but it's one that we really don't want to do. We've got a good well on our hands, its reserves to the state and to Phillips, it's a good well, you just don't want to shut it in and let it sit there for three or four months.

Your -- Everybody's best interests are best served by letting that well produce at some small number.

But since there's so many combinations as to what can happen, we're just saying, we're asking that Phillips be given the discretion to make it up, the condition being that at the end of twelve months the overproduction is zero.

Q. Can you illustrate or quantify what the magnitude is of 123,000 barrels of overproduction in this particular reservoir? What does it mean?

A. Earlier I stated that the oil in place is 1 million barrels for each 40-acre tract.

So the project area for this horizontal well is three tracts. That's 3 million barrels.

What we're asking for is the ability to overproduce the well 123,000. The math is, that is four percent of the total oil in place on the Phillips acreage. We're saying that's a small, insignificant, almost negligible amount of overproduction, such that drainage is a nonissue.

MR. KELLAHIN: That concludes my examination of Mr. Schramko.

We move the introduction of his Exhibits 1 through 16.

CHAIRMAN LEMAY: Exhibits 1 through 16 will be admitted into the record without objection.

And Mr. Campbell?

MR. CAMPBELL: Mr. Chairman, Mr. Kellahin at the start of his opening was more complimentary of my experience over here than he should have been. I haven't presented a case here in almost a decade, and Bill Carr was on the other side of it, so bear with me if the need arises.

But it's nice to be back here again.

CHAIRMAN LEMAY: Thank you, it's nice to have you back.

CROSS-EXAMINATION

BY MR. CAMPBELL:

Q. Mr. Schramko, could you retrieve your Exhibit Number 1, please?

A. Yes.

Q. This plat demonstrates the surface acreage locations of a variety of wells relative to your Application here, and it would appear that the subject area is principally within the potash boundary, correct?

A. That is correct.

Q. Now, your plat does not show, does it, who is the owner of the Section 14 acreage offsetting your proposal to the south, does it?

A. The owner?

Q. Yes.

A. It is the James Ranch unit.

Q. Do you know that Bass is a lessee in that Section-14 tract?

A. I'm hesitating to answer you. We do have people here with our land group. If it's of significance that I know -- I know Bass is the operator of the James Ranch unit. That's as much as I'm willing to say.

When you say lessees and get into certain terminologies of that sort --

Q. All right.

A. -- I don't want to answer and address those questions.

Q. You can confirm, though, can you not, that the Section 14 portion of the James Ranch unit is itself within the exterior boundaries of the potash unit?

A. Yes.

Q. Exhibit Number 2, that is now in evidence, is then a blow-up of the area of your proposed horizontal well; is that correct?

A. Yes.

Q. And again, we do not -- you have not attempted to illustrate ownership to the offset in Section 14; is that correct?

A. I guess that's correct.

Q. Now, as I understand it, you have examined -- prepared to examine three models relative to the work you've done here; is that correct?

A. Can I back up here a second to your question regarding Exhibit 1? I don't know if you're asking me if we failed in our labeling of this exhibit, but over in Exhibit 12 we do list the operator as Bass Enterprises.

Q. No, I'm not --

A. That's not the issue that you're --

Q. I'm not suggesting anything --

A. Okay.

Q. -- nefarious --

A. Okay.

Q. -- there.

A. All right.

Q. You have prepared relative to your tract three models, single-cell tank models to examine the effect of your operations; is that correct?

A. That is correct.

Q. And the parameters of all of those models assumed a drainage radius of only 660 feet; is that right?

A. That is correct.

Q. So that if one were to attempt to overlay the drainage radius in your models over the surface acreage illustrated on Exhibit 2, what -- Can you tell the Commission what generally would be the shape of that drainage radius used in your models?

A. Something on the order of an ellipse.

Q. An ellipse that would extend only slightly into Section 14; is that accurate?

A. I suppose it's possible.

Q. You do not have an exhibit that would overlay the drainage radius you used in all of your models over the surface illustration demonstrated in Exhibit 2; is that correct?

A. You're asking me if I do not have that exhibit?

Q. You did not --

A. That is correct.

Q. -- prepare such an exhibit?

A. That is correct.

Q. But if you were to prepare one, then you could -- it would be roughly an ellipse 660 feet from the centerline of your horizontal well on Exhibit 2, correct?

A. That would be correct.

Q. And generally, if you were to overlay such an ellipse, you would see, would you not, that the drainage area you have utilized in all of your models extends only slightly into Section 14, right?

A. That would be correct, you'd be referring to the drainage area upon the depletion of this well.

When this well has produced its 628,000th barrel, that drainage area could be over on that acreage.

Q. Now, from Exhibit -- Exhibit Number 9 is your -- you have simply provided as background for us to try to explain the -- to try to understand what a single-cell tank model is; is that right?

A. Sure.

Q. And as I read that Exhibit Number 9, a core parameter of your reservoir studies using this closed-tank model is that outside of this closed tank, outside of this single cell, which we have defined to be 660 feet in an ellipse, that there is a no-flow boundary outside of that ellipse; is that correct?

A. That would be correct.

Q. So that applied to Exhibit Number 2, then, you would assume -- your studies assume that there is no flow into your single-cell model from acreage beyond a relatively small portion of Section 14; is that correct?

A. Except to say that it was calibrated using a vertical well --

Q. Right.

A. -- that does drain 40 acres, and that our expectations would be that this horizontal well would behave similar to three vertical wells.

Q. Right.

A. So when you say it's on a no-flow boundary, it is in part an assumption, but it is also a determination.

Q. Well, but --

A. But if you're asking me if oil will move, yes, oil can move.

Q. Yes, but with respect to the model you have used, you have assumed there would be no movement of oil into your ellipse from acreage outside of your ellipse; is that correct?

A. Well, as I stated, it is -- it is in the model in that fashion. You're calling it an assumption, I'm saying it is part assumption and part a determination.

Q. Now, Exhibits 5 and 6, sir, are geologic maps; is that correct?

A. Yes.

Q. And particularly Exhibit 6 is an isopach map showing the thickness of the pay zone in the area that we're examining; is that right?

A. It is the gross sand thickness, yes.

Q. And it would appear to me, again, that your mapping here, or the mapping that was done here on Exhibit 6, does not demonstrate with any particularity the thicknesses as you move south into Section 14, the James Ranch unit; is that correct?

A. Yes, it was deliberately stopped there because of well control. I think you can reasonably assume the lines continue without there being well control down there.

Q. Right, that would be a reasonable geologic assumption, would it not?

A. Sure.

Q. So can we conclude from your Exhibit Number 6 that the pay thickness in Section 14 immediately to the south of your acreage would be approximately the same as the pay thickness where you're proposing your horizontal well?

A. That would be a reasonable assumption.

Q. Now, was it your direct testimony, sir, that you do not understand the protest that Bass is making in the case?

A. Yes.

Q. Do you understand that they are here to demonstrate that this special test period and overproduction will drain acreage in Section 14?

A. Sure.

Q. And you knew that back at the end of the first Examiner hearing, did you not, on the basis of a letter that was read into the record by representatives of Bass?

A. Did I know what?

Q. That Bass's protest was that your activity presented them with potential drainage of their acreage? You knew that then, did you not?

A. If you leave this concern to the words "drainage", yes, I knew that. But that's the extent of what I --

Q. All right. Did you attempt to modify or supplement in any fashion the modeling that you had done in the previous hearing, based upon your understanding that Bass's concern was offsetting drainage?

A. Did I do additional model runs?

Q. Yes.

A. No.

Q. Now, you talked a bit about this issue of rate-time analysis and it being an industry fact that Phillips is a pioneer in that area?

A. That is correct.

Q. And it would appear to me, not being technically astute, that the purpose of a rate-time analysis is to examine reservoir performance. Generally, it's conducted over an extended period of time; is that right?

A. Yes.

Q. You're examining a production decline as a function of time; is that right?

A. Correct.

Q. And rate-time analysis is -- There's nothing new about that in the oil and gas industry, is there not?

A. There's new inventions and techniques that come out every day.

Q. The general core concepts of rate-time analysis, decline-curve analysis, have not changed over time to any real --

A. They've changed tremendously over time.

Q. It occurs to me that what you're asking to do here is speed up in time your ability to analyze data that you would otherwise have to wait for a period of time to examine; is that a fair statement?

A. No.

Q. You are wanting by your Application today to produce these wells at open flow absolute capability, are you not?

A. Yes.

Q. And you first asked the Examiner to do that for twelve months, correct?

A. Correct.

Q. You are now asking the Commission to do that for six months; is that correct?

A. That's correct.

Q. And it's your purpose in doing that, as I understood your direct testimony, to obtain data relative to decline circumstances and production data sooner than you otherwise would, correct?

A. No, it's the only way I can. Not sooner. The only way.

Q. Wouldn't that analysis be applicable to every oil well in the State of New Mexico?

A. What analysis is that?

Q. Your analysis that you should be entitled to an expedited production in order to assess the data that is yielded from that expedited production in a reservoir?

A. This is a horizontal well being drilled in unusual circumstances. I don't think it should be compared to every well in the State of New Mexico.

Q. Okay, but I thought you had indicated that the horizontal well we're talking about here, you expect no overall difference in performance than you would get from three vertical wells. Did I misunderstand you?

A. No, you didn't misunderstand anything. I think the difference here --

Q. Uh-huh.

A. -- is when we talk about vertical wells, when I have drilled our last vertical well, I went into that with a complete understanding of what my expectations were by comparing it to offset production.

I was probably accurate in forecasting its initial rate within plus or minus five, ten percent. I would never stand here and say that on a horizontal well I can make that same determination within five or ten percent. What we have done here are expectations that we think are reasonable.

Q. Have you ever participated at any prior hearing at the Commission in which such an expedited overproduction had been sought for purposes of retrieving test data?

A. No, I have not.

Q. And I think I heard you say that you personally created this concept of seeking overproduction for an extended period of time; is that --

A. I'm responsible for having thought through the rate-time benefits, yes.

Q. I mean, this concept of overproduction for an extended period of time at the start of production would aid you in assessing rate-time effects, would it not, as an engineer?

A. Yes.

Q. I mean, it would aid any engineer, would it not?

A. Yes.

Q. In any well?

A. Yes, but in some wells it wouldn't be as necessary as with this one. In many wells, I couldn't demonstrate 100,000 barrels of incremental potential recovery.

Q. Well, would it be beneficial, in your professional judgment, with respect to every horizontal well?

A. I'd have to look at each individual circumstance, but it is something I might consider.

Q. Does the existence of a potash boundary here have any particular impact on whether you need it or not, or is it just the horizontal nature of the well?

A. The element is present. Given our choices, we'd rather drill three verticals. We're obligated to drill a horizontal if we are to recover the reserves that are out under drill locations N and O.

Q. And you're not expecting any real difference in ultimate recovery due to the fact that this is a horizontal well versus three vertical wells, are you?

A. Could you ask that again?

Q. You're not expecting any real differences in ultimate recovery due to the fact that this is a horizontal well versus three vertical wells?

A. That's correct.

Q. Now, could you turn to Exhibit Number 16, if you would, sir? This is a summary table of your expected overproductions if you -- if Phillips is granted the

Application; is that right?

A. That's correct.

Q. And this is the same exhibit you introduced in the Examiner's hearing?

A. That's correct.

Q. And all we would be looking at here relative to your modification today of the test period from twelve to six months, we can then look at the overproduction that would occur in six months rather than in twelve, correct?

A. That would be correct.

Q. Now, do I read the table correctly to appreciate that at the end of six months, you anticipate you're going to be 123,000 barrels overproduced?

A. Correct.

Q. Versus your expectation of being overproduced 147,000 barrels at twelve months?

A. That is correct.

Q. So again, not being an engineer, it would appear to me that approximately 84, 85 percent of the overproduction that will occur if this Application is granted will occur in the first six months; is that right?

A. Yes.

Q. Now, I think you testified at the Examiner's hearing that you -- There is an oil-water contact in your acreage; is that right?

A. That is correct.

Q. And have you determined how close to the oil-water contact the horizontal borehole will be?

A. Twenty-five feet.

Q. Is that -- That's relatively close in terms of your business?

A. Relatively close? In terms of --

Q. Where you would want to be or where you --

A. It's where it's going to be. I'm not sure I understand the question.

Q. Well, do you anticipate that your well is going to produce water, sir?

A. That we can't be sure of. I really don't know.

Q. I mean, your models don't have any water flow criteria in them, do they?

A. That's correct, they are not two-phase, which is what I think you're asking me.

Q. That's probably --

A. They're single-phase.

Q. That's probably what I'm asking.

Would the presence of water or your -- If you encounter water and produce water relative to your horizontal production here, would that affect ultimate recovery, in your view?

A. With that limited amount of information you just gave me, I can't answer that question.

Q. Well --

A. The well will be the well, and I will analyze what we get. To make a gross assessment of whether water would damage ultimate recovery or not, without any other information, I couldn't say.

Q. Okay. Well, you've prepared here a risk analysis, Exhibit Number 15?

A. Yes.

Q. And that risk analysis, I assume, does not contemplate that you're going to encounter water, does it?

A. No, that would be correct.

Q. Okay. So --

A. It doesn't consider whether I would or would not.

Q. So if there was an oil-water contact point 25 feet from your wellbore, as you say, out in the real field, when you begin producing, that -- there is a possibility that you're going to produce a significant amount of water in this well, isn't there?

A. It's a possibility.

Q. And that might affect, mightn't it, the risk analysis that you've undertaken here?

A. I think you're asking me if I can still perform rate-time analysis if a substantial amount of water is produced?

Q. Oh, no, even I know that you can still --

A. Okay.

Q. -- produce -- you can still do a rate-time analysis if you're producing water.

What I'm saying is, if you're producing water, might that change the risk analysis you've assumed here in your study?

A. No.

Q. May I have just a minute, Mr. Commissioner?

Now, you mentioned a couple times that there's a submersible pump in this well.

A. Correct.

Q. Is that to pump the oil?

A. Pump the fluids, whatever fluids --

Q. Isn't it a fact that you have a submersible pump in this wellbore, sir, to pump the water?

A. It's going to pull all the fluids.

Q. And you would expect it to pull water within 25 feet of the wellbore, would it?

A. No, I would not.

Q. Do you recall any testimony in your prior -- in the prior Examiner's hearing on the question of whether you expect to encounter water here?

A. No, I don't.

MR. CAMPBELL: That's all I have, Mr. Examiner.

CHAIRMAN LEMAY: Thank you, Mr. Campbell.
Mr. Kellahin?
MR. KELLAHIN: A couple points on redirect, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Schramko, can you approximate for us the cost of this horizontal well versus the cost of a single vertical well?
A. The cost of this well would be $1.8 million horizontally.
A typical vertical well can be drilled and completed and put on line for about $650,000.
Q. When you're dealing with a horizontal well that costs potentially $1.8 million, is it of significance to you as an engineer whether or not you recover all the recoverable oil that that well will produce?
A. Most definitely, it's significant.
Q. Does the 100,000 barrels of oil that potentially is at risk under your illustration pose a significant amount of oil in terms of the profitability of that expensive oil?
A. Most definitely.
Q. Would you afford to Bass the opportunity to conduct the same type of testing procedures for their well,

should they ever decide to drill a horizontal well in their unit area?

A. Yes.

MR. KELLAHIN: No further questions, Mr. Chairman.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. In the fairway, there are about seven to eight wells that have produced consistently very close together, the same types of figures for the production rates and initial production.

If this well is located also within the fairway with all three of the quarter-quarters within that area, wouldn't it be very obvious at the initial production whether or not it was skin-damaged or not?

A. No. I can say it this way: If that's the only parameter you give me, is the initial production rate, two possibilities: The permeability is higher than we estimated. And if I double the permeability -- that's going from .2 millidarcies to .4 millidarcies -- I would expect twice the initial production rate initially.

So if you tell me the initial production rate is 1600 barrels a day, that could be a well that has permeability of .4 and lots of damage. Or it could be a well that has the exact permeability that I've put in this model with no damage. Both are fair and possible.

Q. Do you plan on taking cores of this well as it's --

A. No. Horizontal cores? No.

Q. Several other questions.

Within the fairway for those seven to eight wells, was the reservoir very homogeneous, isotropic, in its character, would you say?

A. Is the reservoir homogeneous?

Q. Yes.

A. We have seen a recent core in the James E 16 which is in Section 12. It's -- On any of these diagrams, it's shown as a dry hole. We just drilled it this year, a few months ago. We saw a core in that, and it is very homogeneous, extremely homogeneous, more homogeneous than any core I've ever seen.

Q. What type of water cut do you have for the other wells within Section 11?

A. Less than 50 percent, approximately. Probably in the range of 30- to 50-percent water.

Q. Because of the problems that Phillips encountered with the potash line cutting through that particular section, would that same restriction apply to any well locations in the section just to the south?

A. I would think so. Again, I'd like to emphasize that the potash line that I drew is our approximation.

The BLM does not provide us with the exact location of where that line is, which is why we end up going through these multiple gyrations of where to locate wells.

So I'm drawing that based upon wells that I know we've either applied on and been denied, and then I'm connecting points. And we also have the general map that -- I'm not sure who puts it out, but that gives you the general trend of where the potash line is. So the combination of the two tells us that, yeah, the land to the south of us should have the same potash dilemma.

COMMISSIONER BAILEY: Thank you.

CHAIRMAN LEMAY: Commissioner Weiss?

COMMISSIONER WEISS: Yes, I have a couple questions here.

EXAMINATION

BY COMMISSIONER WEISS:

Q. Who's the potash operator? Do you know?

A. We notified two potash companies in the area. One was Mississippi Potash and the other was Western Ag Minerals.

Q. And they wouldn't deal with you, huh?

A. Wouldn't deal with us?

Q. Yeah, or is it the BLM or is it the --

A. BLM.

Q. -- potash that says you can't do that?

A. That's correct, BLM.

Q. I see.

On Exhibit 9 -- Prior to that, I think you have some assumptions that you put into Exhibit 9, and that would be the permeability on Exhibit 8?

A. Okay.

Q. Where did those numbers come from?

A. We have cores, as I mentioned, in the James E 16. These are whole cores, in the James E --

Q. That's a dry hole, isn't it?

A. Pardon?

Q. That's a dry hole?

A. Yes, dry hole in the sense that we didn't case it and put it on, but there was pay encountered, there was 12 feet of producible hydrocarbon pay. That wasn't adequate enough for us to justify casing, so while it was a dry hole, there was commercial pay.

We also have cores from four wells, three or four wells, up in the -- Section 2, and those cores, analyzing the data, would suggest these levels of permeability.

Aside from that, that's all the core data, all the permeability data that we had.

Q. Okay. Well, then, if we use those numbers, I guess looking at Number 9, Exhibit 9, on equation (6-8) at the very end --

A. Equation (6-9), okay.

Q. I think that's a steady-state flow equation, and it includes skin there in the denominator.

A. That's correct.

Q. And it also includes permeability in the -- the two different permeability -- or just one permeability in the numerator, so I guess --

A. The other permeability is in there. That's the beta term, the vertical perm.

Q. Okay.

A. In the numerator of that equation there's a B, beta.

Q. Okay.

A. Oh no, excuse me, that's not it. The beta is in the denominator, excuse me.

Q. B, Okay.

A. That's B. Beta is in the denominator.

Q. So you've got -- I take it, then, that you have to have -- you have to know the horizontal permeability before you can solve for skin; is that right?

A. In this case, we input the parameters and said, Give me a forecast.

Q. And that's how you solve for skin?

A. No, I haven't solved for skin.

Q. I thought that's what this was all about, skin damage.

A. What this is about is getting a rate-time analysis so I can determine the exact skin once the well is drilled.

For the time being, what we've assumed in the model is a skin of -- it's a horizontal skin, it's a skin of .5, which can't be related to a vertical skin.

Horizontal skins are different. We've assumed a .5. That's a number that's reasonable.

COMMISSIONER WEISS: I have no other questions.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Okay. What's the GOR, roughly in --

A. Most of the wells are --

Q. -- the wells in Section 11?

A. -- approximately five --

Q. Pardon?

A. Excuse me. About 500.

Q. 500?

Back to the risk -- Let me try and phrase it a little differently than legal counsel for Bass did.

Is there a possibility of coning with higher withdrawal rates? Is that an additional risk? You can cone water in that well, it would be 25 feet from the -- what amounts to an oil-water contact with some water being produced already?

A. I would say no, based upon the exhibit where I addressed fluid velocity, and I'd like to go into that maybe in a little more detail

What I'm saying is, if this well, this horizontal well, produces at 1600 barrels a day, and compare that to a vertical well that's producing at 300 barrels -- and let's call it fluid instead of oil, fluid -- that the fluid velocity within the vertical well is seven times more than a horizontal well.

What that's saying to me is, I could produce this horizontal well at seven times higher than what we're talking about. That would be roughly 10,000 barrels a day.

If all things are right, then that well would not pull fluids any harder than a vertical well would. So I'm not at all concerned about the fluid -- the movement of fluids through the reservoir, the possibly of producing at 1600 barrels a day, being a damaging thing.

Q. The nature of being a horizontal well reduces the risk of coning --

A. That would be true.

Q. -- given different rates of fluid withdrawal?

A. That would be true, especially since in vertical wells they are typically completed with hydraulic fracture, which grows down into the water.

In this case, we're taking a chance -- we'll drill it horizontally -- there's the chance that we completely stay away from the water and have a 100-percent oil well. It's possible.

It's also possible -- And thinking back to a question I was asked earlier, I think I did allude to this around the same issue in my original testimony, was that, yeah, the well could produce 25 percent water, 50 percent. We don't know what the answer is going to be.

There's no -- There's very little data that you could put here that and say that this flow rate is going to cone water.

So we're saying we'll drill the well, see what we can get. I can still perform rate-time analysis, whether or not it makes water or not. So the water isn't really of concern to me.

Q. Okay. My last question concerns that make-up table I think you have, which is Exhibit 16.

What would happen -- And we all know how risky drilling is. What would happen if you came in, say, with your highest production being 700 barrels a day, like month nine? You'd still be over the top allowable rate, but you'd be falling -- We've had this problem come up.

Everyone says, I'll make up the production. But they're assuming they'll make up top allowable production, when in essence over time the well would fall below the top allowable. And by getting that early production you wouldn't be making up enough oil, considering the decline curve from that point.

A. My statement to that would be, okay, if the well came on at 700 barrels a day, within about -- judging from the numbers I'm looking at here, within about the 13th or 14th month, we would be at the allowable rate.

So beyond that point, of course, the well would be producing less than the 561 allowable.

And I think what you're asking me is, there would be -- by virtue of producing the well wide open, that well would naturally go below the allowable, and in a natural set of events would make it up so that I don't have to shut the well in; is that correct? Is that what you're alluding to?

Q. Yeah, and it's -- It's more when you're when you're competing in the reservoir with another well. I'm saying you're getting your oil early.

A. My statement would be that we are going to produce the same cumulative oil in the first year, whether the test period is granted or not.

And while there is the issue of competition, we're saying that the amount of overproduction is so small that the movement of fluids across these lease boundaries are negligible, and that Bass has every opportunity to get in there and compete, whether or not they opted to do the special test period.

If for some reason they chose not to do a test period, they're still going to get the same recovery whether we had the test period or not.

Q. I guess that's the item of disagreement. They feel that fluids will be migrating across their lease line to your well that they will not recover, and you're saying that will be negligible or that they will recover their share of oil under their lease, whether you get the increased allowable early or not.

A. If it's safe to say that Bass is waiting on us to drill our well, which is -- would seem to be a fair assessment, because they've known we were going to drill this well for a number of months now, they could have rushed out there and drilled one -- I think it's safe to maybe say that they're going to wait on the results of our well, see what we get, start the ball rolling to put their own well in.

That's going to be six months down the road.

That's at a point in time in which, in the worst case, we're shut in.

So when I think of the movement of fluids, they would be in a position -- if the conditions were that for six months we've produced and now we're shut in, and the seventh month they're at TD and they start producing, now all of that oil that moved in our direction is now moving back towards them, because we're shut in, in the worst case.

Q. Do you have a drilling island to do that, to protect their correlative rights? Well, I guess the best thing is to ask them that question.

A. Yeah.

CHAIRMAN LEMAY: That's all I have.

Any additional questions of the witness?

COMMISSIONER WEISS: One more.

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Did you plan to core this well?

A. No.

COMMISSIONER WEISS: That's all I have.

CHAIRMAN LEMAY: Additional questions?

You may be excused, thank you.

Let's take a 15-minute break.

(Thereupon, a recess was taken at 10:05 a.m.)

(The following proceedings had at 10:20 a.m.)

CHAIRMAN LEMAY: We shall resume.

I assume that concludes your presentation, Mr. Kellahin?

MR. KELLAHIN: That concludes our direct case, yes, sir.

CHAIRMAN LEMAY: Thank you.

Mr. Campbell?

MR. CAMPBELL: Mr. Chairman, we would call Ronnie Platt as Bass's first and only witness.

I'd like to distribute, if I might, copies of the exhibits we intend to utilize. I'm giving Counsel a colored set.

C. RONALD PLATT,

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

DIRECT EXAMINATION

BY MR. CAMPBELL:

Q. Would you please state your name, sir?

A. My name is Ronnie Platt.

Q. And where do you reside, Mr. Platt?

A. In Austin, Texas.

Q. By whom are you employed?

A. I've been employed in this matter by Bass Enterprises Production Company.

I am a consulting petroleum engineer and president of Platt, Sparks and Associates, a consulting engineering firm.

Q. We all know that you testified at length yesterday and moved through your qualifications and educational and professional background, but Ms. Bailey was not at that hearing, as I understand.

Could you summarize quite briefly your professional background and expertise?

A. Yes, I graduated in 1962 with a bachelor of science in petroleum engineering from the University of Texas, employed immediately after graduation by Standard Oil Company of Texas, through name change became known as Chevron.

I was with Chevron in various capacities throughout west Texas, New Mexico and other mid-continent areas, for about 14 years, resigned in 1976, established a consulting petroleum engineering practice. I've been engaged in the practice of consulting petroleum engineering work since that time in 1976.

I formed Platt, Sparks and Associates in 1980 as a consulting engineering firm with -- I was the only employee. It's now a staff of 34, with offices in Austin and Midland, Texas. And we serve a wide variety of clients from major oil companies, state government, federal government, foreign governments, individuals, banks, a large variety and a large number of clients.

Q. And your expertise and qualifications have been tendered to this Commission and Hearing Examiners before here in New Mexico on numerous occasions, have they not?

A. Yes, I've testified previously before those.

Q. And on all of those occasions, your credentials have been accepted by the Commission and your expertise recognized?

A. Yes.

MR. CAMPBELL: I would tender Mr. Platt as an expert petroleum engineer for purposes of the hearing.

CHAIRMAN LEMAY: He is so qualified.

Q. (By Mr. Campbell) You have familiarized yourself, have you not, Mr. Platt, with the Application that Phillips has filed in this proceeding?

A. Yes, sir.

Q. And what is your understanding of the protest that Bass is making with respect to the overall Application and effort of Phillips in this matter?

A. Bass is concerned about the capacity, authority being granted to the well, to produce extended, in fact, large volumes of oil in excess of the allowed production, that that will have adverse impacts on the offsetting Bass acreage, that would cause drainage.

Q. Does Bass pose other objections at all to the overall effort of Phillips, aside from the overproduction and time limit matter?

A. No, the three times allowable to account for the three 40-acre units, I think, is reasonable for a horizontal well to avoid the vertical wells.

So the 561 allowable that was requested and approved by the Examiner, I think, is reasonable for a horizontal well.

What Bass is objecting to is the authority to produce in excess of that top allowable.

Q. What have you been asked to do, Mr. Platt, specifically with respect to that issue?

A. To make a reservoir engineering study to assess the impact on the offset Bass acreage, by authority that would allow the well to produce at capacity, so I've looked to see what the impact would be on the offsetting Bass acreage.

Q. We will move through the elements of your study and your background to that study.

But could you summarize for the Commission before we do that, what the general nature of your findings has been?

A. Yes, I have looked to see the impact on the offsetting Bass acreage, primarily the offsetting acreage

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to the south in Section 14, that immediately offsets the proposed horizontal well.

The results of my study showed that that area will be drained substantially during the first year of production by the capacity allowable rates as -- or capacity production rates, as proposed by Phillips. There will be substantial oil drainage from the offsetting Bass acreage.

I've looked at it both for their requested capacity production, and then since Bass doesn't have a well, I've looked at it, at just the 561, and there would still be drainage at the 561, because Bass doesn't have an offset. But the drainage is substantially increased by capacity production versus the 561 allowable production.

So I've looked at it both ways to see what is the difference, recognizing that there would be drainage without an offsetting well in that first year under either case. I've looked to see what the increased drainage would be under the proposal.

Then I've looked at it beyond, in the year two and year three, under proposed make-ups, to see if Bass is balanced, as far as looking at the reservoir oil drainage.

Q. And have you made certain conclusions based upon your study relative to whether balance will occur here if the Application is granted?

A. It will not occur. The oil that's drained in the first year, a very small portion of that is made up in subsequent years.

Q. Let's begin to move through your exhibits, Mr. Platt. Could you identify and substantiate Exhibit Number 1?

A. Exhibit Number 1 is just a plat that shows in yellow and identifies the Bass acreage with the yellow color. This is the Bass acreage that offsets the proposed horizontal well in Section 11.

Bass is primarily concerned about the direct offsetting acreage in Section 14. Bass has ownership position in the north half of that Section 14, to the acreage immediately to the south.

Bass also has acreage offsetting the proposed horizontal well to the east, and that's shown in this plat.

Q. Would you examine Exhibit Number 2?

This Exhibit Number 2, I would suggest to the Commission, is the same exhibit as Plaintiff's Exhibit 16, I believe.

COMMISSIONER WEISS: This one is marked 17.

MR. CAMPBELL: 17, excuse me.

THE WITNESS: I might explain that the 17 was the exhibit number in the July Examiner hearing, and I just simply copied it out of that Examiner hearing. It was 17 in that hearing. I believe it's a different number in this hearing, but it's the same document.

Q. (By Mr. Campbell) All right. Now, have you utilized, then, what is marked as Bass Exhibit Number 2 in connection with your studies here?

A. That's correct.

Q. So you're using the overproduction figures calculated by Mr. Schramko?

A. Yes, and I used the "Production if Test Period is Granted" column to -- I used that as the production rate schedule for the well for the first twelve-month period.

Q. Could you retrieve Exhibit Number 3 --

A. Yes.

Q. -- and explain to the Commission what that exhibit demonstrates?

A. This is just a graph that I've prepared of the data that was on the prior Exhibit 2, Bass Exhibit 2. This just shows the daily capacity rate or daily production rate, as opposed to the 561-barrel-a-day allowable. So this just shows by month the period of overproduction that was represented by the prior Phillips exhibit.

Q. All right. Now, all of us just found out this morning from Mr. Schramko or Mr. Kellahin that the test period now proposed by Phillips would be six months rather than twelve; is that correct?

A. Yes.

Q. That changes nothing in your analysis except as a matter of degree; is that a fair statement?

A. That's right. It would -- As you see, on this, most of the overproduction on this exhibit, the next exhibit, occurs in the first six months, or over 80 percent does.

Q. Would you retrieve the Bass Exhibit Number 4 and explain that to the Commission, if you would?

A. Exhibit Number 4 is just simply showing the overproduction that occurs each month, so the bottom line with the triangles is the monthly overproduction. That's the barrels of overproduction in excess of the allowable each month under the Phillips proposal.

Then the top line is just summing that up. It's a cumulative figure that shows -- and this shows also -- If you look at six months, you've accumulated over 80 percent of the overproduction in the first six months. So this is just simply plotting to show the cumulative versus time.

Q. And Exhibits 3 and 4 are plotting on the basis of Phillips's calculations of overproduction; is that right?

A. Yes, and it's the exhibit that was presented in the Examiner hearing and the hearing today.

Q. Could you retrieve Bass Exhibit Number 5, Mr. Platt?

A. Yes, Exhibit 5 is a plat that I've drawn on, and this yellow area here is not Bass acreage. I've used -- possibly should have used a different color. But the yellow here, I've highlighted an area that I've done a simulation on so I can look at reservoir -- portions of the reservoir with this horizontal well producing and see where the oil comes from. And this yellow is the area that I've used in the reservoir simulation.

Q. How does the area that you used in your reservoir-simulation modeling differ from the acreage that Mr. Schramko used for Phillips?

A. It's larger. I believe what he used was just a 660-foot radius from the horizontal borehole, and it would more or less parallel the horizontal borehole.

What I've done is expand that to let the reservoir simulator tell me where the no-flow boundary is, rather than imposing them 660 from the well, to impose a -- fix a no-flow as an input.

Q. All right. Your modeling, then, will show the impact on the Bass acreage to the south, with some specificity; is that correct?

A. Yes.

Q. Could you retrieve and identify Exhibit Number 6 --

A. Yes.

Q. -- and explain this to the Commission?

A. Yes, Exhibit 6 is the input data that I've used for the area on Exhibit Number 5. This is -- The name of the software is called an Eclipse 100. It's developed by Intera. It is a software we've used over about the last eight to ten years to do multiphase three-dimensional modeling of various phases of fluid flow in the reservoir.

In this, we've used as a black oil three dimensional. I show the grid size, I have a later exhibit to show the grid size. The grid size is just to impose the number of cells within the area that I've shown on Exhibit 5.

The other parameters, as you'll see, that I've used for the top of sand, the net sand thickness, porosity, permeabilities, pressure, water saturations, gas saturations -- I've used Phillips data. I haven't varied it. I've simply input their data, and that's -- In this record today that's on their Exhibit Number 8.

So I've used Phillips' data for all of the reservoir parameters. Basically all I've done is just increased the size of the reservoir that I'm modeling to look at a larger area, rather than just fixing it 660 feet from the well.

Q. Could you then turn to Exhibit Number 7, Mr. Platt and explain the nature of that exhibit?

A. Exhibit Number 7 is a detail of the area that's shown on Exhibit Number 5, and on this I've shown the grid that has been placed on the area.

And then I show regions, and I've color-coded those. I've identified in the computer and identified certain cells as Regions 1, 2 and 3.

The Region 1 -- so that I can look at simulation results in a reservoir area -- Region 1 would be the Phillips tract, the Phillips lease.

Region 3 would be the Bass tract in Section 14, the offset tract to the south.

And Region 2 would be a strip to the east. That would also be Bass acreage to the east.

But I'm looking primarily at the offsetting area to the south, the Region 3, to see what oil moves from that by producing the well at the proposed Phillips rates or the estimated Phillips requested production rates.

And using the Phillips reservoir parameters, I've investigated that to see what is the oil movement under that proposal.

Q. Would you retrieve and explain Bass Exhibit Number 8?

A. Exhibit Number 8 is a summary of the simulation results. So I've run the model with the reservoir parameters that are shown on Exhibit 6, which are --

they're the Phillips reservoir parameters.

And then I've used the Phillips production schedule. I've run the model for a one-year period. This shows from September, 1994, to September, 1995. And in that one-year period I then look at what the model shows is the current oil in place in these three regions that were shown, and compare it to the original oil in place, and that tells me how much oil is moved out of that region. And then I compare that with the production.

And then this simply tells whether or not there's been oil moving in or out of those various regions.

What this shows in this simulation, as it's identified at the top, is under Phillips -- I call it Special Allowable Case, but it's really a special production case, but this is their request, as I understand it.

So I produced the Phillips horizontal well for twelve months, based on the production schedule they submitted as an exhibit. And at the end of twelve months this shows that the Phillips tract has drained 82,180 barrels from other regions of the simulation.

And this identifies where that comes from. Most of it comes from the Bass Region 3, which is the Section 14 to the south. Those are so identified at the note at the bottom.

But this shows that there's substantial movement of oil to the Phillips tract with the well producing at the requested capacity production rates during this -- This Exhibit 8 shows what happens in the first twelve months.

Q. Knowing now that Phillips seeks to shorten this proposed test period from twelve months to six months, and not having concluded relative to that recent adjustment, can you explain to the Commission what effect a shorter test period might have relative to this issue in Exhibit Number 8 of migration of movement from the Bass tracts to the Phillips tract?

A. I haven't run that case, since I just heard of it this morning, so I haven't had an opportunity to run it.

But since most of the overproduction and most of the large withdrawals from the reservoir -- and that's what the simulator matches, withdrawals and movement of oil to match those withdrawals -- since over 80 percent occurs in the first six months, I wouldn't anticipate much change. There will be some change. The drainage, I anticipate, would be less, but I would anticipate very small change.

Q. Could you then retrieve -- identify and explain Bass Exhibit Number 9?

A. Yes, Exhibit Number 9 is a summary of the simulation results where I've done -- run the simulation with the Phillips well producing at the top allowable rate and not at capacity.

Q. And as I read the chart, then, after the end of twelve months there would be drainage, assuming no special production is permitted, drainage from the -- into the Phillips well from other tracts, Regions 2 and 3, of about 60,500 barrels; is that correct?

A. That's correct.

Q. Almost 60,000 of which come from Region Number 3 in the south?

A. Yes.

Q. And again, what impact would you expect if you ran your model at six months rather than twelve months?

A. Again, a very slight change.

But what this shows in Exhibit Number 9 is that because I do not have any -- in the simulation -- and I've estimated, in fact, there would not be an offset -- there would not be an offset producing well to the south. Even if the Phillips is restricted to the 561 allowable rate, there would still be drainage of oil from the south, even at the 561-barrel-a-day rate.

So I did that to recognize that, to see what drainage it would be if the special production is denied. And there would still be drainage, due to the fact that Bass would not have in place in this potash area an offset well in the first twelve months.

So there would be 60,000. So I've looked at trying to see what additional drainage would be caused by granting this special production authority.

Q. All right. And does Bass Exhibit Number 10, then, show that incremental difference?

A. Yes.

Q. Could you retrieve it and explain the conclusions there to the Commission?

A. Yes, the Exhibit 10 just summarizes. It looks at the difference between Exhibit 8 and 9.

One, I show the proposed special allowable case, and those are the numbers shown on Exhibit 8. And then I look at the regular allowable, cumulative drainage at the end of twelve months, and that's from Exhibit 9. And then I've just looked at the difference.

So the incremental oil drainage, that would be the additional drainage that would result by the draining of the special capacity production authority.

Q. All right. Now, all of these prior exhibits, 8, 9 and 10, are premised on the assumption that Bass does not drill an offset well or wells to the south; is that correct?

A. That assumes that Bass is unable in the first twelve months to have a competing well. That's recognizing several factors.

One, it is in the potash areas, as shown on the Phillips Exhibit 1, I believe, in this hearing. So it would be down, it would take some time. So I would assume that Bass would not have a competing well in the offsetting acreage during the first twelve months of the Phillips.

So I've looked at -- but I've considered that in both cases.

Q. Now, have you also examined in your modeling the prospect of what drainage would occur, even assuming that a -- that Bass were to drill a well?

A. Yes, sir.

Q. Could you retrieve and explain Exhibit Number 11?

A. Yes, on Exhibit Number 11, I've looked beyond the first twelve months and looked at the next two-year periods, and to look to see what is the drainage. And this again would be the cumulative drainage at the end of these additional time periods. And I've shown it by region, and then I've identified the time periods at the top.

Q. Now, let me try to understand what Exhibit Number 11 assumes with respect to when Bass would be able to place a well to offset production in the Phillips tract.

Your exhibit assumes that because of potential difficulties caused by the presence of this acreage in the potash area, that it would be a year -- approximately a year before Bass could place a well to offset the Phillips well; is that a fair -- is that what you have done?

A. Yes, this assumption is that after the first twelve months Bass has a well producing, and I've assumed that it is a horizontal well that's capable of producing the top 561 barrels a day.

So I've made that assumption that that well is in place, then, at the end of the twelve-month period, that Bass has at that time an offsetting well capable of producing the top allowable of 561.

Q. All right. Then could you, based on that assumption, outline to the Commission what your modeling has shown?

A. Yes, Exhibit 11 shows both -- the cumulative drainage for each of the time periods.

The first two columns to the right of where I've identified regions show drainage with special allowable and regular allowable, as of the end of the first twelve months.

Moving to the next two columns, show the cumulative as of September, 1996, for both the special allowable and the regular allowable.

And then the last two columns show the cumulative as of 1997. So that would be the end of the third year, for both the regular and special.

Then the next exhibit, to look at them as I did on the others, you would look at the incremental or the additional advantage that's given by producing under the special production authority requested.

Q. All right. So Exhibit Number 11, then, is showing the gross differentials, based, A, on the assumption that Bass has a well in the offset acreage, and under two cases, one being that their request for special treatment is granted, the other being that it is not; is that correct?

A. That's correct.

Q. All right. Would you turn, then, to -- Well, let's step back just to make sure we're clear here.

Could you summarize for the Commission what those cases show in 1995, 1996 and 1997, relative to whether the Application is granted or not?

A. Well, under -- If you follow across on the special allowable, the -- on Region 1, which is the Phillips tract, under the special allowable, it's the 82,180 drainage at the end of the first twelve months.

At the end of 1996 under this special allowable, it's increased, it's at 98,000.

And then the drainage advantage basically stops. There's only a slight gain at the end of the third year. It goes to 99,236. That's under the special allowable.

Q. And that's flow into the Phillips well?

A. Yes.

Q. What effect do you see, then, for example, on drainage in Region 3, Bass's acreage to the south?

A. The Bass to the south, under the special allowable the loss is the 79,676.

At the end of the second year it's increased to the 94,403.

Then at the end of the third year it's reduced slightly to 93,786.

And then for any time periods after that, it stays at about that same cumulative drainage. After that there's no more net drainage off of the tract. The wells are -- After the end of the third year -- it actually happens during the third year -- both wells are then producing at capacity, so there's essentially no other migration of fluids between the regions.

Q. So you concluded that, contrary to Mr. Schramko, that a balance would not occur between those tracts?

A. That's right. And this is using the Phillips reservoir parameters.

Q. Could you retrieve, then, Bass Exhibit Number 12 --

A. Yes.

Q. -- and explain -- summarize this to the Commission, if you would?

A. Yes, this again is showing the incremental. This would be the difference. What I've followed through or explained on Exhibit 11, I was tracking through the special allowable case and showing the drainage that the special allowable caused to the Bass.

This is showing the incremental. It's comparing the difference each year between the special allowable case and the 561. So this shows how that incremental changes with time.

So looking at Region 3, which is the Bass tract in Section 14, it shows the loss of 21,071 barrels. And this would be the additional drainage that would be suffered in the twelve months, as I previously identified to you, the special production authority versus regular allowable. The special would permit an additional 21,000 barrels to move to the Phillips tract.

At the end of the second year, it doesn't balance up. There's even some additional oil migration in the early part of that twelve-month period, and some slight make-up in the second year. But the net is still greater at the end of the second twelve-month period.

So at the end of 24 months, the cumulative incremental drainage is still in favor -- In fact, it increased slightly, a slight amount higher, so it didn't make up.

Then at the end of the third year, there -- During that second -- latter part of the second year and the third year, there is some make-up. You'll see the number reduces down to 18,000. But then it stays at that amount, because at that period of time, during the third year, the wells are on capacity and there's not any change.

So there is some slight make-up that occurs. It goes from 21,000 to 18,000. But this granting of the special allowable enables the tract to have an undue advantage that can't be made up.

Q. Now, how would you explain, Mr. Platt, the proposition that there would be an increase in drainage from Region 3 -- you said a slight increase -- after Phillips shut in its production to the north? Why would that occur?

A. One, I was curious as to why, so I went in and looked at the model to see why. I thought I knew why, and it confirmed it in the model.

What happens is, after the first year of production without any offset, and producing at this very high rate of over 350,000 barrels of oil are withdrawn in the first twelve months, it draws the pressure down in that region. Now, this is using the permeabilities of Phillips.

So that even when that well is curtailed in year two, or beginning the second period of time, oil is continuing to flow into that region, due to that large pressure drawdown and the large withdrawals over 350,000 barrels of oil in that first twelve months.

So the oil continues to move in, even though they're curtailed. And then it takes a while for the reservoir to adjust and then for the regions to balance out. And so that's why the oil continues to flow in during that period.

And I might point out that the production assumptions I've used for the second six-months period, I assume that Bass's well would come on and produce at 561 barrels per day, as an offset horizontal well. I assumed that the Phillips well in that second period would be reduced to 158 barrels a day, in order to make up the approximate 147,000 barrels of overproduction in the next twelve months.

So that second twelve-month period, I've got Phillips producing at 158 and Bass at 561. But because of the large withdrawals, even though it's curtailed to that, oil is continuing to migrate into the region --

Q. Now --

A. -- the region being the offsetting Phillips, in response to the previous large withdrawals.

Q. It is the case, is it not, as with prior exhibits, that Exhibits 11 and 12 of Bass are based on a twelve-month test period, as opposed to the six-month period that Phillips has recently adjusted to; is that correct?

A. Yes, sir.

Q. What impact, if any, would you expect on your calculations, considering a six-month test period versus a twelve-month period?

A. I think there would probably be some slight revision, and it would be downward. I think it would show less drainage, but a very slight amount.

But I think the overall impact shows that the granting of a special allowable -- or special production authority to accumulate a large volume of overproduction in excess of allowable creates a drainage from the offset tract that's not made up.

Q. All right. You have examined and heard Mr. Schramko testify with respect to the risk analysis presented here. I think it was Phillips Exhibit Number 15?

A. I'm not sure of the number, but I've heard the testimony, the risk analysis, yes.

MR. KELLAHIN: It's 15.

Q. (By Mr. Campbell) Have you as a professional engineer engaged in any similar type of risk assessment, Mr. Platt?

A. I have been involved in risk assessments and risk analyses, yes.

Q. Now, can you tell from the calculation -- from Mr. Schramko's testimony or that exhibit, whether there is any parameter of his study that contemplates water production?

A. As I understood his testimony, there was not.

Q. All right. And you can confirm that water has been produced from all of the wells in this landscape; is that accurate? Or most of the wells?

A. Apparently -- Yes.

Q. Knowing --

A. Water production is anticipated with the wells.

Q. All right. And would production of the oil at the rates requested here, in your opinion, contemplate the potential of water coning for this well?

A. I really don't know. I haven't done a detailed study on water coning.

But the fact that the wells do produce water, you're close to an oil/water contact, you're asking to produce the wells at capacity -- Water coning is by nature rate-sensitive. It responds -- The higher you produce the well, the greater the risk of water coning. And so it is a rate-sensitive phenomenon.

I have not made a unique study of this to see at what rates it would cone, but that is a generally recognized reservoir engineering proposition that water coning is rate-sensitive. And I would have some concern, since these wells produce water, there is a recognized oil-water contact in the reservoir, and asking the wells to produce at capacity and produce very large volumes of oil in a short period of time, to me there would be -- you would have to analyze and assess risk with that also.

Q. In contemplating that prospect of water coning might well occur, what impact would that have on ultimate recovery, realizing that you have not done a full study in this area?

A. Most of the time, if you do cone water into a well -- this is based on my experience -- that will reduce the ultimate recovery. Even though you may curtail the rate later, you've pulled water in that saturates the area with water at a higher water saturation, it tends to reduce the permeability. Even though you curtail the rate, that cone does not ever go totally away, so you've reduced the permeability in the area of the well, which has an impact on ultimate recovery.

Q. In your opinion, is there any method whereby Bass could make up the underproduction that is contemplated as occurring here, the drainage that's occurring as a result of the Phillips Application?

A. I have looked at what I assume is the -- trying to look at the minimum amount of drainage that might occur. And that's assuming Bass is able to get a well on in twelve months, a horizontal well completed and producing, and that.

So I've looked at -- If Bass is not able, then its drainage is even greater. So I've tried to look at it, assuming Bass is successful in getting a well in there in a relatively short period of time to offset this well.

Q. In your opinion, if the requested special production test period is denied, will the ultimate recovery from the pool be reduced?

A. I don't believe so.

Q. Would you then summarize your conclusions for the Commission?

A. The results of my study indicate that the granting of authority to produce at capacity, to produce a very large volume of oil in excess of the allowable rate, recognizing that that allowable rate is already a three-times allowable rate, in my opinion, will cause drainage of oil from the offsetting tracts.

And even if that is made up in later periods of time, due to declining capacities of the wells, which the reservoir simulator recognizes, the reservoir underlying the tract does not recover that oil that's been previously drained. Some very small portion comes back, and that's what the simulator shows.

MR. CAMPBELL: Mr. Chairman, I would move for the admission of Bass Exhibits 1 through 12.

CHAIRMAN LEMAY: Without objection, Bass Exhibits 1 through 12 will be admitted into the record.

MR. CAMPBELL: And then that concludes my direct examination of Mr. Platt.

CHAIRMAN LEMAY: Thank you, Counselor.

Mr. Kellahin?

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Platt, you'll have to bear with me. I'm a first-time listener to your presentation, and I've been reviewing your exhibits as you've presented them.

Let's see if I can understand the modeling situation.

In yesterday's presentation, your presentation was specific about a geologic interpretation that Mr. Hillis presented.

When we look at the application of reservoir simulation in this case, did you attempt to have a Bass expert like Mr. Hillis who, as a geologist, gave you a geologic interpretation of this specific area so that you could model what he believed to be the geologic parameters for this area?

A. No.

Q. Do you have any engineering opinions with regards to the original oil in place that underlies any of these tracts in this specific area?

A. I have looked at the parameters of Phillips, and to me those appear reasonable, so I don't have a significant challenge of the estimates of oil in place as presented by Phillips --

Q. Do you have --

A. -- based on those parameters.

Q. I'm looking at Exhibit Number 8 that you presented.

A. Yes.

Q. When I add up in the first column the three regions, it appears to be about 8 million barrels of oil?

A. Yes, 8 1/2.

Q. And that was within the container, if you will, that you put into your simulator?

A. That's correct.

Q. Do you have any major points of difference between you and Mr. Schramko about the selection of the model that was utilized?

A. The model that he utilized?

Q. Yes, sir.

A. I don't have any disagreement of the model he selected in order to do some engineering calculations about skin damage on the well, to look at -- design a stimulation job.

I don't have any problems with using the model for that purpose to do some engineering calculations of skin damage.

I don't think that's a model that will tell you anything about regional migration or tract damage. Well, it doesn't, in fact. That's just a fact. It doesn't tell you anything about drainage from regions.

Q. The purpose to which he applied his model, do you concur that he appropriately applied his model for his purpose?

A. Well, I'm not sure what all his purposes were, but I would -- I think to look at fluid flows and to look at the potential of skin, he may be able to look at total oil and water. But if he were looking to test rate sensitivity, he has only one mobile phase; he only lets oil flow in the model. He doesn't have any gas flow or any water flow in his model. And if you were looking at other parameters, you may want to consider the two-phase flow in the model to look at the effects of that, and I don't believe that was considered.

The model was simplified to only have, as I understand it, one phase, oil.

Q. Are you recognized, Mr. Platt, as an expert in your industry in rate-time analysis?

A. Not uniquely. I have done rate-time analysis, but I don't hold myself out as a renowned expert.

Q. Okay, based upon --

A. I'm familiar with it, and I've --

Q. Yes, sir.

A. -- done some work in it.

Q. Based on your experience, do you have any quarrel with Mr. Schramko's engineering judgment that he needs some time of production test in order to arrive at reservoir data to let him know whether or not this is a low-permeability undamaged well, versus a high-permeability well that's experiencing skin damage?

A. I think I followed all the question, but I think he's not different than any other engineer that wants all the data he can, as much data as he can, to try to do some engineering-type calculations. I don't fault him with trying to get as much data as he can. I don't think he looked at the impacts on offset tracts in acquiring that data.

And then, I think the need to acquire the data, based on his simulation, is based on, to me, a lot of assumptions about what he thinks he's going to find in this well, as to what is the capacity of the well and what is it going to produce at, and what rates will this horizontal well produce at. And then he's made some assumptions on those, and then based on those assumed producing rates or assumed permeabilities or assumed skin, he then shows if those assumed conditions are encountered, it may or may not show him something in some time periods.

Q. You used lots of his input parameters and assumptions when you put that information into your model, did you not?

A. Not the skin -- not -- I used the parameters that are shown on Exhibit -- Whatever.

MR. CAMPBELL: 8.

THE WITNESS: 6 is mine.

Q. (By Mr. Kellahin) All right. When we look at Mr. Schramko's Exhibit 16, that is his production forecast where he's telling you what he is forecasting his horizontal well to be expected to do?

A. Yes, sir.

Q. All right. When you have all this information in your model, what was the initial production rate that you started the Phillips well at?

A. I produced at this same production schedule. It produced at this schedule. I put that in. I produced the well at that rate.

Q. I'm not making myself clear. His initial rate was 1600 barrels of oil a day.

A. I understand.

Q. Did you start at that rate?

A. Yes.

Q. And did you let your model then flow and forecast what its performance would be, independent of what Mr. Schramko did on this table?

A. I input the production in there, the production schedule that's shown on that. I produced that volume of oil out of the horizontal well, as he had forecast.

The only time I let the modeling is when -- for that period -- first twelve months, I produced essentially that volume of oil.

Q. All right. My question was -- and I'm not sure I made myself clear -- for the sake of understanding, did you put 1600 a day initially in the well and, independent of the rest of the schedule, let that model flow to see what it would do?

A. Not for the first twelve months. I produced during the first twelve months the production that Phillips exhibit said they would produce in the first twelve months if this authority is granted.

Q. All right.

A. So I produced that volume of oil to see what that would do.

Q. You did not take his input parameters, start at 1600 barrels a day and let it flow to see what it would ultimately produce or forecast to be produced on your model?

A. No, I did that in late years to see when it got below the 561.

Q. Okay. So we've got the Phillips well in your model, you match his production, or you input his production levels at the end of each of these months for the twelve months?

A. That's correct.

Q. All right. What did you forecast to be the ultimate recovery for the Phillips well under those assumptions without the Bass well?

A. I didn't run it out to the full ultimate depletion. I ran it for the three years, and then I made another special run recently just to run in year four, to see if there was any net migration across the tracts, and at that time both wells were producing at capacity.

But I didn't run it out to some assumed abandonment conditions and look at the total ultimate.

Q. Okay, so --

A. I would have cums at the end of those time periods --

Q. I understand.

A. -- from each of the wells.

Q. I'm just trying to see what you did or did not do.

So you did not run the model to show what the ultimate recovery would be from the Phillips well without a Bass well in the reservoir?

A. No, except for the first twelve-month period. After the first twelve months, I have a competing Bass well in. And that's true in all of my runs; I have a competing Bass well at the end of twelve months.

Q. I understand both engineers agree there's going to be fluid migration in the reservoir.

My point is, I wanted to find out if you have investigated what is going to be the net effect on ultimate recovery.

A. I haven't run it out to ultimate, but I've run it out to the end of the third year, and I have another one at the end of the fourth year.

The Phillips well produces in that period of time in the neighborhood of -- over 600,000 barrels of oil, is the cum production at the end of those periods.

Q. When we look at your Exhibit Number 8, we're dealing with about 8 million barrels of oil in place.

Under the special test allowable, if granted, under the assumption of a year, Region 1, then, has 82,000 barrels of oil? Is that the way to read this?

A. It has acquired 82,000 barrels of oil from other regions that's moved into it.

Q. Okay, it's about one percent of the original oil in place, within the container that you have modeled here?

A. One percent of the total reservoir, yes, that's modeled.

Q. All right. And then when you modeled it again, using the 561 rate for the Phillips well, without the special period?

A. 60,000.

Q. All right. So when I look at Exhibit Number 10, the 21, or 21.6, 21,000 barrels of incremental oil is the additional oil within this time frame that accrues to the benefit of Region 1, which is the Phillips spacing unit?

A. Yes, it's the additional benefit that they enjoy by drainage, the requested special production over what they would get with just the 561. So that's the additional drainage they would have in that first twelve months.

Q. Okay. I'm confused about the size of area, Region 1 and 2 on Exhibit 7.

When we look at your color display, is that equivalent for region 1? Is that the 120-acre spacing unit?

A. I'm sorry, I lost you. Exhibit 7 and 5 go together. Exhibit 5 is the -- what I've -- Exhibit 5 is the reservoir simulation, then I've just simply shown the grid in detail that I've imposed in that area in Exhibit 5.

Q. All right, I don't have that exhibit. Tell me quickly, Region 1, is that the south half of this section? How big an area is that?

A. Region 1 is -- Region 1 is the area -- it's the area that's depicted -- Well, I can give you dimensions, but it's shown on Exhibit 5.

Q. Okay. Is it -- It's 40 acres high and --

A. I can give you the exact dimensions.

Q. -- a section wide?

A. Well, let me get -- I can give you a footage. It's shown on the map, and then if you want an exact -- Let me get --

Q. All right, I'm sorry, Mr. Platt, I have found this.

A. Okay.

Q. I'm looking at Exhibit 5, and it appears that the area you've simulated is simply to take a laydown 160 for the Bass acreage, which is, you know, four 40s in a row, and for the Phillips acreage it looks like four 40s in a row.

A. Yeah, this -- It's shown on 5, that's the area that I've simulated, yes.

Q. All right. On Exhibit 10, then, as of September of next year, at the point where you say Bass may have a well, the net uncompensated drainage, if you will, at that point is 21,000 barrels of oil?

A. Well, actually the net uncompensated drainage is 82- -- is over 80,000 barrels.

Q. And the difference attributable to the special test would be the incremental 21,000?

A. That's correct.

Q. All right. Where's the display that shows us the time sequence where you put the Bass well on production after the end of the twelve months?

A. I don't know that I have exhibits. I just testified to that. I have the actual simulation.

But that's the production that I put the Bass well on and limited it to 561 barrels a day, beginning at the beginning of year two.

Q. All right. What's the basis for your assumption that the Bass well will only come on at 561?

A. Well, I limited it -- I didn't assume that it would come on at that. I limited it to the top allowable.

Q. Okay. Did you try to run your program to see, if Bass was provided the opportunity for a special allowable equivalent to Phillips's, what would happen under that circumstance?

A. No, I did not run that case.

Q. The case you've run, then, is Mr. Schramko's production forecast on Exhibit 16 for which, at the end of the first year, then, you're going to restrict his well to 158 barrels of oil a day?

A. Yes.

Q. And at that point in time, it is competing with the Bass well, which comes on at 561, and you hold 561 constant through the period of time that you've described?

A. I hold that as a top allowable rate. It either produces at capacity or 561 after that period of time. And there is a period of time it begins in the beginning -- into year three, where neither well will make the 561, so it's produced at capacity.

Q. Okay. Did you run that hypothesis to its conclusion so we could see what the ultimate oil recovery is under that set of circumstances for the Bass well and the Phillips well?

A. I didn't -- As I've testified, I haven't run them out to the ultimate final depletion. I ran for a four-year period of time to look at regions and cumulative productions and migration of oil in the reservoir, and then I didn't run out the additional time steps to the ultimate depletion.

But after the end of year three, these wells were then declining at capacity. The allowables were not impacted on the wells, they...

Q. I was trying to find out if you had analyzed in terms of ultimate recovery for any of the wells what the net effect would be of granting the test.

A. I haven't run it out to the ultimates, but I have made comparisons between the productions at the end of the periods.

The -- I run out for four years, and the Phillips well produces about 30,000 barrels more oil in that four-year period, with the draining of the proposed special allowable, than the -- When I say "special", under the special production authority it produces about 30,000 barrels more in that four-year period than under the normal, regular allowable than the well declining at capacity.

And at the end of year four, the Bass offset hypothetical well and the Phillips well are all at capacity.

At that period of time, I've got cumulative production from the Phillips wells and -- well, the Phillips well -- in the neighborhood of 650,000 barrels. But there's -- It has accumulated production of about 30,000 more under the special production case.

And I believe that that would probably carry it through to final depletion, that incremental difference.

Q. You haven't run the calculation to see what that total number would be for either well?

A. No, just to year four, and at that time we've got wells declining at capacity.

Q. All right. You and Mr. Campbell had a brief discussion about potential water coning in the reservoir?

A. Yes, sir.

Q. Are you aware that the convention in the pool is for the operators to fracture-stimulate these wells, and in doing so, are highly likely to communicate with the water leg that's lower in the reservoir?

A. Fracture stimulation is a normal completion procedure. Whether or not it allows communication with the aquifer, it may vary in wells as to where the source of the water being drawn into the wells is coming from.

Q. Did you have any quarrel with Mr. Schramko on his velocity calculation, the velocity information he shows where a vertical well is likely to have almost seven times greater velocity than the horizontal well?

A. I didn't have an opportunity to go through those calculations in detail, so I just really can't comment on those.

I haven't had an opportunity to study those.

Q. What's the basis for your assumption that the

Bass well comes on at the end of a twelve-month period?

A. In visiting with Bass about offset well, as to what is the earliest possible date they could forecast, after Phillips makes a successful completion how soon could they have a well in the reservoir, and that was about the earliest they could forecast being able to have a well permitted in this potash area, drilled and on production, and that's based on discussions with Bass.

And I think that's making some very broad assumptions, very optimistic assumptions, if you look at the generalized potash outline of --

Q. Do you know whether or not they've obtained the approval of a surface location for drilling in any portion of Section 14?

A. I don't know, I don't know.

Q. Have you attempted to run your model under your assumptions, but put the Bass well in the reservoir earlier than twelve months?

A. No.

Q. Does it make a difference in whether or not the overproduction is equalized, if you will, between the project areas, if instead of allowing the Phillips well to continue to produce at 158 barrels of oil a day, that at the end of the twelve-month period it is simply shut in? Do you know what the effect of that would be?

A. I haven't run that case, but it would still show oil moving in.

Most of the migration starts because of the large withdrawal in the first twelve-month period.

Q. Does the effect -- Are these numbers affected by the size of the container that you have modeled?

A. They could be, but I've looked at that and I believe I've got a large enough container to account for most of the regions, or most of -- to include enough grids where oil movement is occurring in response to the withdrawals.

Q. Okay. Do you see what I'm looking for? I'm looking for a boundary effect --

A. Yes.

Q. -- for the size of the container that you've selected.

A. Yes, what I tried to do was to go to a large enough grid so that I would not impose some artificially assumed no-flow-boundary.

I was trying to go out large enough in that, and the only exception I made was in an east direction.

Q. The assumed boundary on the east is the one that's shown on Exhibit Number 5 where it approximates the section line?

A. Yes, sir. It's slightly over into the Bass acreage to the east.

Q. Mr. Schramko's assumption, I guess, his best-case assumption, was the initial productivity of his well was about 1600 barrels of oil a day.

Based upon your work, do you have any other number to suggest to us about the highest expected rate for the horizontal well?

A. No, I just simply assumed that it would produce at 16- --

The production as forecast by Phillips, I just simply assumed that was the production schedule, rather than trying to generate some other schedule. I just used what Phillips said they thought they would produce out of the well.

Q. All right.

And so that's the only case that you ran in terms of what initial rate, as well as subsequent rates for the Phillips well, is the schedule they proposed?

A. Yeah -- Well, the other case was assuming the well produced only 561 a day until its capacity was not 561.

MR. KELLAHIN: Okay. Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Questions for the witness?

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. In view of the restrictions for drilling locations because of the potash factors here, I'm looking for the realistic ability of Bass to produce oil in the north half of the north half of this section.

Given the costs that Phillips gave us, that it would -- a horizontal well is about three times the cost of a vertical well, I'm looking for a location, even, that Bass could choose in order to drain this portion of the section.

Have you any thoughts on that kind of a question?

A. Yes, Bass is very concerned about that and is working on how that might be developed, since there does appear to be the potential of the reservoir extending into that area and how are those reserves developed.

And so I've assumed that Bass is able to work with the BLM and the potash and somehow get a well drilled over there, somehow, from an island, an offset or a long-lateral-reach well.

So I've sort of made assumptions to see what the minimum drainage would be, assuming that could be accomplished.

If that's not accomplished, the drainage would be even more.

Q. Okay. Does Bass have any experience drilling horizontal wells in this area?

A. Bass has drilled numerous wells that are lateral wells. Bass has done extensive drilling in the area of the potash and has deviated wells long distances, over 2000 feet, to reach bottomhole locations.

So they have had directional drilling experience, considerable.

COMMISSIONER BAILEY: Okay, that's all I have.

CHAIRMAN LEMAY: Thank you, Commissioner Bailey. Commissioner Weiss?

COMMISSIONER WEISS: I have a couple questions.

EXAMINATION

BY COMMISSIONER WEISS:

Q. What does Eclipse do with the vertical permeability in a 2-D model?

A. Oh, it's a 3-D model.

Q. But I only saw the XY grid blocks, I didn't see any Z grid blocks.

A. No, we have a Z. The Z, we just have one cell in that direction, but we put in the thickness. So we have a vertical thickness in there. It just is one cell thick, but we have a dimension in that direction.

Q. Doesn't it have to flow from one cell to the other in order to use the permeability?

A. No, it handles the flow within the cell there, based on the vertical permeability there. The Eclipse model will handle that.

We have a 40-foot-thick reservoir section, and within that 40 foot Eclipse we'll handle the vertical and horizontal components of fluid flow.

Q. Okay. And then the oil drainage in Region 2 didn't reflect production from that Well 48 in Section 12, did it?

A. No, the -- I can explain. I put in basically a no-flow boundary to assume Well 48 keeps the drainage from encroaching any further onto the well in the east section. That's basically how I got the limits on that side.

I assumed that that well would have performance as such that it would keep it from encroaching in that section.

Q. And then how much water was produced with the oil in your calculations?

A. I used the Phillips parameters in which they have no water movement. So I didn't produce any water.

I used the same reservoir parameters on this to just look at oil movement in the regions, assuming that there was not any water coning or water production.

I was looking primarily at where was oil going to move under using the same parameters Phillips was using?

Q. I guess I don't understand how you did that with initial water saturation of 50 percent. Seems to me like the well would have to produce water.
A. I didn't have it a mobile phase. I didn't allow it to flow, so that just reduced the pore volume in there, and it was not a mobile phase.
Q. Okay. So then the pressure differences in these grid blocks are not realistic, are they?
A. I believe they are, under the -- To account for the oil withdrawal, they would be realistic --
Q. Yes, yes.
A. -- pressures, yes.
Q. Oh, yes --
A. Yes.
Q. -- no question.
A. Yes. But I did not -- I tried to stay with the Phillips characterization of the reservoir as much as possible and look at just oil flow under their proposal, because their proposal did not give me a water production schedule either. So they didn't have a mobile water phase. So therefore I was trying to model their oil phase.
COMMISSIONER WEISS: That's all the questions I have. Thank you.
CHAIRMAN LEMAY: Thank you, Commissioner Weiss.
I -- It may be difficult for you to answer for

Bass, because I understand you're a consultant, but -- Go ahead.

COMMISSIONER WEISS: I had one other question, but that was the most important one.

Q. (By Commissioner Weiss) When was the last time Bass got a permit in the potash area?

A. I would have to defer that to somebody else. I may be able to find that out for you from some of the Bass people that are here.

CHAIRMAN LEMAY: I had the same thing.

COMMISSIONER WEISS: Yeah, everybody's --

THE WITNESS: I'm not sure what year.

CHAIRMAN LEMAY: We're all worried about Bass protecting their correlative rights because of the BLM.

I mean, that's not even the subject of this hearing.

It may come up at some point in our careers.

THE WITNESS: Bass is very concerned about how to do that also.

But I was trying to look at the just issue in this hearing, and assuming we could get around that other problem, I'm not -- and that may not be --

COMMISSIONER WEISS: Perhaps the Commissioner could --

THE WITNESS: -- but I was --

COMMISSIONER WEISS: -- some Potash.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Well, maybe I could phrase this question as to what you would recommend, being familiar with the situation.

Would you recommend or do you think Bass would be interested in doing the Phillips-type decline curve?

In other words, your general testimony as I've interpreted it has been, it's okay if Phillips wants to do this, but we don't think we need this type of analysis on our acreage if and when we can get our horizontal well drilled?

A. Bass doesn't see any need to conduct that type of test on their well. At least, it doesn't have any plan to do that type of testing in order to deplete the well.

And then Bass is concerned, since Bass doesn't plan that type of testing procedure, at least at this time, in my discussions with them, for their well, and the time delay, the granting of this special exception for the offsetting well is very detrimental to Bass.

Q. Well, then, even if you would adjust the time frame, any incremental allowable, would it be your testimony that there would be uncompensated net drainage with any increase in allowable granted them, even though it was made up?

A. Yes. At least under the six months. Now, it's just an order of magnitude. If it's only one month, then it would be reduced even more.

But I think the authority to produce in excess of the allowable -- to allow the wells to produce at capacity is giving them an advantage, that causes drainage from the offset.

Q. And that's Bass's main concern. There is no level of uncompensated drainage that would be acceptable?

A. We would prefer there would be none, but Bass has realized -- And that's why I ran the case at the 561. Even if the special production is denied, there's still going to -- there's going to be some drainage that Bass can't offset, even under that case. And that's why I looked at the additional drainage, to see --

Q. Yeah, but that would be fair under the rules of capture. I mean, Bass supposedly should be able to protect themselves.

A. That's it, theoretically they should --

Q. Theoretically they should.

A. -- if they were able to just go and drill a well, that's it.

Q. Normally that would be the case.

One more question, for curiosity --

A. Yes.

Q. Would it be possible -- I mean, what is the maximum horizontal distance effectively that can be drilled at this depth to be able to connect 40-acre units together? How far can you go out there horizontally with technology today that may be as economically feasible?

A. There have been wells drilled over 12,000 feet laterally in other areas.

Now, the unique drilling experience in formations in this particular area, that may not apply. But in my experience there have been -- I've been involved in California and other -- and some of the Austin chalk wells that have been drilled for very long lateral distances, some over 4000 and 5000 feet. Some of the long-lateral-reach wells that reach some of the offshore properties in California are up to 10,000 to 12,000 feet of lateral projection to reach some of the offshore reserves from onshore.

So the technology is there to drill very long distances laterally.

Now, again, you'd have to address the specific formations encountered here to see how far you could go in this situation. But I'm trying to answer generally in experience. The technology is there to drill a very long distance.

Q. With your experience with this formation, how far would you recommend they could drill and be effective laterally?

A. I don't know. I think it's reasonable to assume that you can go through three of the units. How much more than that, I don't know. I'd have to do a study. I just would be reluctant to respond without looking at that specific study.

CHAIRMAN LEMAY: Thank you very much. That's all the questions I have.

Additional questions of the witness?

MR. KELLAHIN: No, sir.

CHAIRMAN LEMAY: Okay. Let's leave the record open for a couple weeks for draft orders and --

MR. KELLAHIN: I know we're a little short of --

CHAIRMAN LEMAY: Do you want to sum up?

MR. KELLAHIN: No, sir, I think I prefer to utilize my time to, with your permission, recall Mr. Schramko --

CHAIRMAN LEMAY: Fine.

MR. KELLAHIN: -- for a few comments --

CHAIRMAN LEMAY: Sure.

MR. KELLAHIN: -- and then let Mr. Campbell and I prepare draft orders on the topic for you.

But in lieu of a statement of opinion, I simply would like to recall Mr. Schramko.

To expedite the process, Mr. Chairman, let me have the flexibility to simply give him a narrative question, if you will, or invite a narrative answer.

CHAIRMAN LEMAY: Okay.

KEN SCHRAMKO (Recalled),

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. Schramko, you've had an opportunity to listen to Mr. Platt's presentation and express his concerns for Bass about your project. Has anything he has described for the Commission caused you to re-evaluate your position or change your conclusions?

A. No, nothing.

Q. What is your assessment of his intentions about the fact that there's going to be net uncompensated advantage, if you will, or drainage, the advantage to Phillips at the expense of Bass, if the test is granted?

A. I was looking for some statement that said that the ultimate recovery from the Bass acreage would be reduced.

What we've seen so far is that there would be movement of oil, which we don't deny, that there would be this -- and he quantified it for us at 20,000 barrels of oil, because of the test period.

My contention is that ultimate recovery would be the same, and by stopping short in his model at three or four years, he didn't follow this process out to its logical completion, in which case he would have likely seen, but we can only speculate since he didn't make the runs, that the recoveries would have been the same.

Q. Any other comments or observations you want to make to the Commission before we conclude?

A. Yes, two.

I don't compare myself to other engineers who are in here asking for big things, engineers wanting lots of data. I sit here as a rate-time analysis expert, recognized within Phillips Petroleum, telling you this is special circumstances, this is a special case, where granting this special test period can in fact, because we're talking about a horizontal well, recover additional oil. That's one point.

Second one is, I want to make sure that I was clear in my usage of the model that I selected. I had really just one objective, and I didn't hear anything from Mr. Platt's testimony to refute that.

My objective was to show that this horizontal well could produce at a rate of approximately 1680 barrels a day.

Once I had that accomplished within my model, to show that the rate is 1680 barrels a day, all that served was the basis for me asking for the magnitude of the special test period.

From this point forward, I don't need to know anything else about the well, other than the basic flow parameters, thickness, porosities, things of that sort, to calculate permeability and skin.

In other words, the rate-time analysis that I will perform isn't dependent upon what's going to happen, will we cause skin? That's why I'm running the test. In other words, I will tell you what permeability is, I'll tell you what the skin is, if we run the test.

I think there was some confusion about that because I heard several individuals alluding to the fact that perhaps I needed certain things to happen from this point forward in order to be able to perform rate-time analysis. That's not the case. It stands alone. The model for was obtaining an expectation.

Once that expectation is done, now I can perform rate-time analysis, and in fact determine exactly what permeability and skin are, as opposed to what I've put in the model at this point to estimate what it might be.

That's all I have.

MR. KELLAHIN: Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Thank you.

Questions of the witness?

MR. CAMPBELL: No, sir, but I'd like to use about two or three minutes just to summarize our case. But the Examiners --

CHAIRMAN LEMAY: We have a couple questions here quickly.

So Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Am I clear here that you can get skin out of a steady-state flow equation?

A. Yes.

COMMISSIONER WEISS: Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. This is more of an economic. We've been talking about, Mr. Schramko, the net uncompensated drainage, and I think you were at least inferring or I understood your testimony to be that ultimately that would be made up and that Bass wouldn't be handicapped because maybe at the end of the life they'd get a little each year and they'd finally make it up.

But even granting that scenario, would you agree to some economic loss because of time, use of money, it would take a while to make that extra production up toward the end of the reservoir?

A. I find something a little unusual here, and that is that his models started at 561 for the Bass well. Under that condition, I would agree, there's going to be a movement of oil in our direction.

Why wouldn't Bass want to bring their well on at 1680 barrels a day like we're going to do? That's a condition that he didn't run. And had he done that, the movement would have been less significant than 20,000 barrels, far less significant. It would have had to have been. But we can only speculate on what the actual numbers would have been.

Q. I thought I asked him that very question, if he would recommend that. But his answer was that he wouldn't, so that's probably the reason. Whatever his reasons were.

A. In a drainage -- In a competitive environment is, I guess, what I'm alluding to.

Q. Oh, I see.

A. We're competing for oil, but -- is free to move across, and we're giving them the authorization to produce at 1680. I'm at a loss unless you believe it would damage the reservoir, and I heard nothing in them to suggest that it would. Why wouldn't you want to produce it at 1680?

Q. I guess what you're suggesting is that, assuming we would grant your request, that then he might change his mind on wanting to get that advantage?

A. I think that's a fair statement.

CHAIRMAN LEMAY: All right, I'm sorry. I'm just trying to get where you're coming from.

That's all I have, Counselor.

MR. KELLAHIN: That completes my rebuttal.

CHAIRMAN LEMAY: Thank you.

Mr. Campbell?

MR. CAMPBELL: I'll waive closing, Mr. Chairman.

CHAIRMAN LEMAY: Okay.

Anything else in the case?

MR. KELLAHIN: No, sir.

What's the time frame for your -- our submittal?

CHAIRMAN LEMAY: Can you get a couple -- two weeks? Would that give you enough time to give us some draft orders?

MR. KELLAHIN: Let us try for that, and we'll call you if we're --

CHAIRMAN LEMAY: If you have a problem let me know and we can leave it open longer.

MR. KELLAHIN: All right, sir.

CHAIRMAN LEMAY: And Elizabeth, good luck to you.

MS. HARRIS: Thank you.

CHAIRMAN LEMAY: We've enjoyed having you in the state.

MS. HARRIS: Thank you.

CHAIRMAN LEMAY: We shall take the case under advisement.

Thank you very much, gentlemen. Appreciate your cooperation.

Thereupon, these proceedings were concluded at 11:35 a.m.)

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CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL October 9th, 1994.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1994