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 CONOCO, INC., TO AMEND DIVISION ORDER NO. R-11,139, RIO ARRIBA COUNTY, NEW MEXICO	CASE NO. 12,556

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

December 7th, 2000

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner, on Thursday, December 7th, 2000, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

December 7th, 2000
Examiner Hearing
CASE NO. 12,556

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A P P E A R A N C E S

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ALSO PRESENT:

FRANK CHAVEZ
District Supervisor
Aztec District Office (District 3)
NMOCD

RICHARD K. DEMBOWSKI
Petroleum Management Team Leader
Farmington Field Office
Bureau of Land Management
Farmington, New Mexico

* * *

WHEREUPON, the following proceedings were had at 12:35 p.m.:

EXAMINER CATANACH: Call the hearing back to order, and at this time I'll call Case 12,556, which is the Application of Conoco, Inc., to amend Division Order Number R-11,139, Rio Arriba County, New Mexico.

Call for appearances in this case.

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

EXAMINER CATANACH: Call for additional appearances.

MR. KELLAHIN: In addition, Mr. Examiner, I'm appearing on behalf of Burlington Natural Resources Oil and Gas Company. They support the approval of Conoco's Application.

EXAMINER CATANACH: Can I get the witnesses to please stand to be sworn in?

(Thereupon, the witnesses were sworn.)

MR. KELLAHIN: Mr. Examiner, the record should also reflect that the Bureau of Land Management desires to make a formal appearance in this case. They have sent an expert petroleum engineer to testify in this case. He is the Petroleum Management Team leader; it's Mr. Richard K.

Dembowski. He spells his last name D-e-m-b-o-w-s-k-i. And he would like to make a sworn statement at the conclusion of Conoco's presentation.

EXAMINER CATANACH: Okay.,

MR. KELLAHIN: With your permission, Mr. Examiner, let me explain why we're back before you.

On February of 1999, you issued Order R-11,139. It approved Conoco's Basin-Dakota pilot infill project in the San Juan 28-and-7 Unit. That order was limited to six infill wells.

We're now back before you to report the status of the pilot project, to seek your approval to expand the pilot to include the entire unit, to have you specifically authorize nine additional infill pilot wells, eight of which are at unorthodox locations, and to establish an administrative process so that we could potentially expand the pilot within this unit to include future additional wells if deemed necessary by Conoco.

And the presentation will be made in three parts. We have a land presentation, a geologic presentation, and then an update on the status of the engineering work, which includes a witness on reservoir simulation.

And with your permission, we'll call our first witness. Mrs. Jennifer Barber is the land expert for Conoco, and she'll be the first witness.

JENNIFER BARBER,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mrs. Barber, for the record, ma'am, would you please state your name and occupation?

A. I'm Jennifer Barber, I'm a landman with Conoco in Houston.

Q. You'll have to speak up. That microphone will not amplify you voice, and there is a hum in the heater fan over my head, so I can't hear you.

A. I'm Jennifer Barber, I'm a landman with Conoco in Houston.

Q. On prior occasions, have you testified before the Division?

A. No, I haven't.

Q. Summarize for us your education and your employment experience with regards to being a petroleum landman.

A. I have a bachelor's degree in minerals land management from the University of Colorado. I've been employed with ARCO in their Tulsa office, Denver office, Midland office, and with Conoco in Midland and in Houston.

Q. You obtained your degree from Colorado in what year, Mrs. Barber?

A. 1982.

Q. As part of your responsibilities as a landman for Conoco, are you familiar with the ownership and configurations of the San Juan 28-and-7 Unit?

A. Yes, I am.

MR. KELLAHIN: We tender Mrs. Barber as an expert petroleum landman.

EXAMINER CATANACH: She is so qualified.

Q. (By Mr. Kellahin) Let me have you turn to what is marked as Exhibit 1 and have you identify what we're looking at.

A. This is a map of the 28-7 Unit showing all the currently existing wells. In addition, the wellspots in solid black are the Dakota wells that were drilled in our initial pilot, the wells in bright yellow are the nine wells that are being proposed in this pilot project. The yellow border along the interior of the unit is a one-half-mile buffer, showing that all nine wells are well within that boundary.

Q. The outside edge of the yellow buffer area is contiguous with the outside boundary of this unit; is that not true?

A. Yes, that's true.

Q. Within the unit, has there been established a

Dakota participating area?

A. Yes, there is, there's a Dakota participating area which encompasses the entire unit, with the exception of a 320-acre drillblock in Section 21 of 27-7 and in the southwest quarter of Section 18 of 27-7.

Q. The drillblocks within the unit that are not part of the Dakota participating area are substantially removed from the additional nine pilot wells?

A. Yes, they are.

Q. All right. Were you responsible for providing notification of this Application to interest owners?

A. Yes, I was.

Q. And how did you go about doing that?

A. We mailed a copy of the Application to the 20 other working interest owners in the unit by certified mail.

Q. Did you receive any objection from other working interest owners within the Dakota portion of the unit?

A. No, we did not.

Q. Identify for us Exhibit Number 2. Is this your certificate? Oh, I'm sorry, you have a different set here. Would you identify Exhibit Number 2 for us?

A. It's a certificate of mailing of notices to the working interest owners in the unit.

Q. And attached to the certificate, then, is the notice letter and then copies of the return receipt cards for those individuals or companies for which notice was sent?

A. That's correct.

Q. And in the absence of a green card, there are copies of the two notification receipts that they were, in fact, sent to those individuals?

A. That's correct.

MR. KELLAHIN: All right. That concludes my examination of this witness, Mr. Examiner.

We move the introduction of Exhibits 1 and 2.

EXAMINER CATANACH: Exhibits 1 and 2 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Let's see, Ms. Barber, these are the 20 working interest owners in the unit; is that correct?

A. Yes, sir.

Q. I don't recall from the last case, but are these the same owners that were notified in the first case? Do you know?

A. Yes, they are, with the exception of Unocal, who sold their interest to Burlington; they're no longer in the unit. But the remainder are the same.

Q. Okay. The first time around, we didn't, as I recall, notice any royalty interest owners in the unit; is that your understanding?

A. We did notify royalty and overriding royalty owners in the last hearing.

Q. Okay. And do you know why that wasn't done in this particular case?

A. Well, all of the categories of owners will share equally in production.

Q. Okay. With the exception of the nonparticipating acreage in Sections 18 and 21; is that correct?

A. That's correct.

Q. You've chosen to expand the buffer area to include all of the acreage in Section 18 and all of the acreage in Section 21, because of that fact?

A. Yes.

Q. And we didn't notice any offset operators because of the buffer zone that we put in place; it doesn't really have any effect on the offset operators; is that correct?

A. That's correct.

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

MR. KELLAHIN: All right, thank you.

Mr. Examiner, our next witness is Mr. Marc Shannon. Mr. Shannon is a petroleum engineer. He provided the engineering testimony at the first hearing in February of 1999.

MARC SHANNON,

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

A. My name is Marc Shannon. I'm a staff engineer with Conoco in Houston, Texas.

Q. Mr. Shannon, you testified as an expert petroleum engineer before the Division at the original hearing of this case, did you not?

A. I did.

Q. And you continue to work for Conoco in the capacity of a petroleum engineer responsible, along with others, for this pilot project?

A. That is correct.

MR. KELLAHIN: We tender Mr. Shannon as an expert engineer.

EXAMINER CATANACH: Mr. Shannon is so qualified.

Q. (By Mr. Kellahin) Mr. Shannon, let's take a moment and have you turn to Exhibit Number 3. Let's use this as our locator map and have you identify for us.

A. Yes, sir. Exhibit 3 is actually extracted from the Exhibit 1. It's essentially the same map, but it covers the area where the proposed pilot expansion wells are, so we're looking at essentially the same map, just on an expanded basis.

I draw your attention, Mr. Examiner, to the southeast quarter of 34. That's the 225E well, which was one of the six pilot wells, and we'll be referring to that in a minute. But it's essentially the same map.

Q. Let's use Exhibit 3 as a map to keep us oriented as to the various portions of your testimony, Mr. Shannon, but let's go back and refresh Mr. Catanach's recollection of the original objectives that you presented to him back in 1999 for the pilot project.

A. Yes, sir.

Q. Now, you've done this in the way of a summary fashion, have you not, so that each of these conclusions you're about to express are in the form of an exhibit and a display?

A. That is correct.

Q. Let's do that by turning to Exhibit 4 and talking about the original objectives of the pilot.

A. Okay, Exhibit 4 summarizes what Conoco's original objectives were with the six-well pilot that it was granted under OCD Order R-11,139. In that situation we had essentially three main objectives.

One was to determine the proper well density, of course, in the San Juan 28-7 Unit for the Basin-Dakota Gas Pool.

Secondly, calibrate and refine the initial reservoir simulation that we had at the time, which was a bit simplistic because it was based on the data, of course, that we had at the time.

And then third and finally was to share those results with the other interested parties, being mainly the working interest owners in 28-7, one of whom is Burlington, and obviously they've had a lot of interest in our work here.

Q. All right, those are the original objectives. Mr. Catanach issues and approves the order of the original pilot, Conoco goes out and drills the six pilot wells. What were the results?

A. Okay, the results will be summarized in the next six or seven exhibits, starting with Exhibit 5, which summarizes what Conoco experienced with that first Dakota pilot, namely six wells were drilled, logged and tested, beginning late 1999, and we concluded that work earlier this year.

We did acquire pressure date from each of the wells by zone, which was a little more work than what we had originally, I guess, discussed before this court last year.

We did take production tests in each of the wells, put each well on production, and we did find some reservoir heterogeneity, and we did feel that there was some additional technical work warranted, just based on those results.

So in summary, the data that was taken was very useful, and we have utilized that data in our modeling. And at this juncture I guess Conoco is very pleased with the pilot results, and we're ready to move forward with it.

Q. Let's talk about the type of data that was acquired. Let's go to the topic of the log and the coring data that was derived from the original six wells, if you'll turn to Exhibit 6.

A. Okay, Exhibit 6 summarizes our log and core program. We did log the 225E, which I mentioned earlier. That core was taken through the Twowells, the upper Cubero and just the very upper portion of the lower Cubero. It was our intent to get more core than that, but due to problems with the lower Cubero's splintering off, we weren't able to get any core, very little core, in the lower Cubero.

We also took approximately a dozen sidewall cores in the 234M in all three of the major horizons. We ran a full suite of open-hole logs in each of the six wells, including a dual induction and a set of porosity logs. Then finally, we did run three additional special type logs. One in particular was in the 225E where we ran a spinner survey.

Q. Turn to Exhibit 7, Mr. Shannon. Summarize for us the Conoco core results.

A. Certainly. Exhibit 7, we're talking about the core results in that 225E well. One feature that saw was, of course, the natural fracturing that we saw primarily in the lower Cubero. The permeability, geometric mean, was approximately .007 millidarcies.

Porosities did vary fairly widely, 4 to 10 percent. In the upper Cubero and the Twowells it was closer to the 8- to 10-percent range. In the lower Cubero it was more in the 4-percent range. So we did have some range in porosity.

Water saturations also varied somewhat, from 35 to 50 percent, but again in our main pay sands was more in the 35-percent range.

Overall, describe the core showing a fairly low-permeability set of sands, with some heterogeneity and some recognizable amount of fracturing, but not a significant amount of fracturing.

Q. Let's set aside the core results now and turn to Exhibit 8 and have you summarize for us the results obtained from the pressure test.

A. Right, Exhibit 8 summarizes the pressure test, and this is probably some of the most descriptive data that we acquired. What we saw there was in the Twowells an average of approximately 2500 p.s.i. Given that the original pressure was in the 3100- to 3200-p.s.i. range, obviously we're seeing some, albeit modest, amount of depletion in the Twowells.

Upper Cubero, same situation, not quite as much depletion, with an average of about 2700 p.s.i.

The lower Cubero saw very little depletion, and that was closer to 2900 p.s.i. on average, so we only saw a couple hundred, 300 pounds depletion in that lower Cubero.

All the pressures were taken from bottomhole pressure bombs, and we ran multiple gauges in each one of these wells. So we have what we believe to be fairly accurate pressure data. So we're very pleased with the pressure data that we were able to acquire on all six wells.

Q. The Dakota Pool within the unit is subdivided, in this portion of the pool, into these three layers?

A. That's correct.

Q. We've got the Twowells, the upper Cubero and the lower Cubero. And as a result of the pressure now, you have isolated the pressure differentials per layer?

A. That is also correct.
Q. And you have that data now?
A. We have that data.
Q. Okay. Let's see the results of production from the six wells, if you'll turn to Exhibit 9.
A. Yes, Exhibit 9 summarizes the production results, which I personally found to be very encouraging that we were able to see these kinds of rates.
The 30-day average IP was approximately 1100 MCF per day. That would be the average for the 30-day period for the six wells.
In the 60- and 90-day averages, we were seven hundred and forty-some MCF per days; and 90 days, 665 MCF per day.
I might add that in the 60- and 90- day tests we only had five wells on production in the Dakota at that time. One well only went for 45 days due to a mechanical problem, so we had to take the well off test. But in all cases we saw very similar decline rates. Obviously, they were all hyperbolic declines -- we'll see that in the next exhibit -- and we did not see any boundaries or unusual flow behavior in any of the six wells.
Q. Do you have a display that plots the production over time for each of the wells in the initial pilot phase?
A. Yes, sir.

Q. Let's turn to that. Exhibit 10?

A. Exhibit 10, yes, sir. Exhibit 10, I apologize for the appearance; it's a busy slide, but it does show graphically what I just described in Exhibit 9.

The longest test that we had was the 225E well, which was the well that we cored, and it went approximately 230-some days. The shortest test, as I mentioned earlier, was the 219M, which was a fairly abbreviated test due to some mechanical problems.

The reason for showing this is to simply illustrate the hyperbolic nature of the wells and the consistency that we saw. Most of the wells leveled out at approximately 500 MCF per day.

A couple other quick things about this. One, I found that production -- I think we all felt that it was pretty encouraging what we did see. And you do see a few little bobbles in each one of these wells, and those are just pipeline and system upsets, pressure bobbles. So that's not really the reservoir; it's something that happened on the surface.

Q. If you go back to Exhibit 1 with me for a moment, which is the plat that locates the original six pilot wells, they're the ones shown on this display with the black circle, right?

A. That is correct.

Q. And they're generally scattered through the upper two-thirds portion of the 28-and-7 Unit?

A. That is correct.

Q. The density pattern established for the original pilot wells provided an opportunity to test on the concept of one additional well, if you will, to a 320-acre spacing unit that contained two.

A. That is correct.

Q. So we're adding a third well. And under that analysis, what conclusions have you reached as a result of having done the work up to now?

A. Okay, if we can move to the next exhibit -- it would be Exhibit 11 -- we'll go ahead and address the conclusions from that work.

Number one, as I mentioned earlier, obviously, we took pressure data in each of the six wells and by layer, the data which did not exist anywhere, at least in our unit, and I'm not really certain that there would be data like that anywhere in the Basin.

Secondly, we did see some differential depletion, albeit fairly modest, in the Twowells and the upper Cubero, and very little in the lower Cubero.

Production results were generally encouraging. We did have some good core data that we've been able to utilizes. And then finally, the acquired data was utilized and did fill in some gaps in our understanding in the Dakota.

Bottom line is this: We got the data that we had gone after. The data was used to further our understanding and, as I mentioned, filled in some of the gaps in our knowledge. And based on the production rates we saw, we're very encouraged by that and feel that the Dakota is viable.

Q. Was not the original hypothesis in February of 1999 the opportunity to test whether or not additional wells could be drilled, completed and produced successfully in the Basin-Dakota Pool, at least within the unit?

A. That's correct.

Q. As a result of that test, you have concluded tat at least one additional well is appropriate?

A. That is correct.

Q. Where do we go from here?

A. Okay, next step. We can move to Exhibit 12. With our new learning and what we believe to be the situation with the Dakota, we would like to take it to what I consider to be at least the next most logical step, and that would be to look at 80-acre infill wells again, but on a much tighter, more concentrated area than what we did the first go-around.

And if we refer back to the Exhibit 1, we can see how those wells are arranged in a sort of a rectangular grid, but in a much smaller area. And what we would like to do next is to continue the pilot testing of 80-acre infill wells, but just on a much smaller basis, much smaller area than what we did the first time.

So in Exhibit 12, as far as the objectives there, one, acquire additional data to further calibrate the model. And Mr. Boneau will be discussing the model here momentarily.

Secondly, test the economic viability once again, but under a new scenario where wells will be located in the more confined space.

And then finally, continue the ongoing dialogue that we have with Burlington and our other working interest owners and industry as far as the Dakota testing is concerned.

The data requirements are almost exactly the same. We need bottomhole pressure data, and we need flow rates from the Dakota.

Q. Describe for me, Mr. Shannon, why you selected an area around the original pilot well 225 -- Yes, it's the 225E in Section 34. Why was that selected of the original pilot wells to then take to the next expansion stage?

A. There's actually several reasons. If we look at Exhibit 14 just for a second, that gets to this 225E, number one, that particular area is a moderate gas-in-place area. In other words, we have some areas where we have more gas in place, other areas where it's a little less. But in this particular area we will see all three of the main Dakota sands, and the gas in place was moderate or average for the area.

Secondly, the 225E, as I mentioned earlier, was a well that we cored. We had an extensive amount of logs, so it just made sense to us to go to an area where we already had some data that we could tie back to with the additional wells.

Also, it's an area where we'll be able to access the Mesaverde once we've concluded the Dakota tests. It's an area where we were able to access most of the locations with existing road, and that was important.

And then finally, as Ms. Barber attested to a moment ago, the Mesaverde and Dakota PAs cover this area. So when we do go to the Mesaverde, it will also be in the Mesaverde participating area.

So we had several reasons for selecting this area.

I might add, we did look at other areas. We looked at offsetting each of these pilot wells, and this particular area around 225E seemed to meet all of the criteria that we had.

Q. If the Examiner approves the further expansion, by what method, then, are you going to test the opportunity to prove your hypothesis about the necessity for further well density?

A. Okay, if we could look at Exhibit 13, which outlines the methodology that we propose to use, and that would be, of course, to drill the nine wells in a very similar fashion to the first six that we drilled. We would log the Dakota interval in each well so we'll have something to tie back to the 225E. Obviously we need to take additional bottomhole pressure data. We need to know what the pressure is of the less permeable sand within the Dakota, and that can only be gained by bottomhole pressure testing. And then stimulate the Dakota and produce the Dakota as a single completion.

I might add also, the bottomhole pressure testing would be done prior to fracturing each well, and that's exactly what we did the last time. Then once the testing is concluded, we would propose that we come up, complete in the Mesaverde and downhole commingle the two zones, which again is what we've done. All six of the previous wells are producing from the Dakota and the Mesaverde now.

Q. Let me address with you, Mr. Shannon, the specific unorthodox well locations.

A. Okay.

Q. We have nine additional wells being requested this time. Eight of them are at unorthodox well locations.

A. That is correct.

Q. Have you reviewed the Division published docket for the hearing of this case?

A. Yes, I have.

Q. Are all the footages properly described for each of those wells?

A. They are properly described.

Q. Of the eight unorthodox well locations, one of those wells is to be directionally drilled, is it not?

A. That is also correct.

Q. Let's find on Exhibit Number 3, the plat, which well that is, and let's discuss it for a moment.

A. Okay, if we could look at Exhibit 3, in the southeast quarter of Section 27 you'll see a Number 190F [*sic*]. That location could not be reached as a vertical well, we could not reach it due to topographic considerations. It lies under a mesa, or the side of a mesa, and we could not physically reach it from any existing roads.

So of the nine locations, eight will be vertical wells, and then this 190F location will have to be drilled as a directional well.

Q. What is the reason Conoco is choosing to engage in the additional time, effort and expense of directionally drilling a Dakota well for this phase of the pilot project?

A. The reason for that is -- perhaps if we look again at Exhibit 3 -- these wells generally form a rectangular grid or a pattern. The 190F completes that pattern, along with all the existing Dakota completions. So we felt that 190F -- it's part of the pattern; it was just unfortunate that it physically could not be reached as a vertical well.

Q. So in order to have an appropriate data point for purposes of the science project, it was useful for Conoco to decide to spend the extra money to try to position this in the reservoir at a data point that was appropriate?

A. Yes, sir, that's correct.

Q. Have all the rest of these unorthodox locations been placed because they are appropriate for gathering data in the reservoir at that position?

A. They are.

Q. Are any of these positions achievable under the current well-location patterns of the existing rules?

A. They are not. We looked at this very closely, and given the locations, the parent wells and then the first infill wells, it was just simply not possible to locate them any other way.

And then too, given the fact that we do have mesas and different types of topographic considerations, we just could not put them anywhere else.

Q. Do the current requested locations for each of these wells already satisfy the approval conditions of the Bureau of Land Management or anyone else that needs to approve the surface use for these wells?

A. Yes, we met -- In fact, our right-of-way-claims staff met with the BLM and reviewed each one of these locations on site, each location. So the BLM has been very much involved as far as knowing where the locations were and signing off at that appropriate time, but they very much are informed as to what we have here.

Q. Have you made a technical presentation to representatives of the Bureau of Land Management concerning this expansion of the pilot project?

A. Yes, sir, we have.

Q. In addition, have you made a presentation to Mr. Frank Chavez of the Aztec office of the Oil Conservation Division?

A. Yes, sir, we have.

Q. Have you met with other operators and/or working interest owners that are interested in this pilot project?

A. Yes, we have. Burlington Resources, in particular, has been very much informed, and vice-versa, when they had their hearings here several weeks ago. And being a large working interest owner in the unit, obviously, they have a lot of interest in our pilot expansion.

So we have met with them, and I have personally visited with them on the telephone on a number of occasions.

Q. Mr. Shannon, are you confident enough now about the appropriateness of this pilot project to ask the Division to expand its approval of the pilot to the entire San Juan 28-and-7 Unit, with the exception, obviously, of the buffer area that's not to be encroached upon?

A. Yes, sir, I am.

Q. Do you have a request that the Division establish an administrative process so that you can obtain approval for additional pilot wells on the basis of your opinion that those are necessary and appropriate to further study and expand the pilot project?

A. Yes, sir, I do.

Q. Do you have a recommendation that such a request be processed administratively without requiring the necessity of an administrative hearing?

A. Yes, sir.

Q. Okay. Summarize for us, if you will at this point, Mr. Shannon, what do you see the importance for the approval of the expansion of the pilot?

A. Yes, sir. What we are proposing here today, why we're here today, is to discuss the results of the first six wells, but to take it to the next step, and that being to test 80-acre infill drilling in the Basin-Dakota Pool under a different scenario whereby the wells to be drilled, in addition to the wells that are already existing in these four or five sections, will provide us with the data that we need to further refine our model, giving us more confidence than we already have.

We're very pleased with the data that we've already acquired, but there's still more data that I think needs to be acquired, but under this scenario here that we've been discussing, and I think that will make the picture a little more complete than it is now.

MR. KELLAHIN: That concludes my examination of Mr. Shannon. We move the introduction of his Exhibits 3 through 14.

EXAMINER CATANACH: Exhibits 3 through 14 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Shannon, in addition to the nine wells that you're proposing today, how many more wells do you think are going to be drilled in this unit?

A. In an 80-acre fashion?

Q. Yes, sir.

A. I do not at this point anticipate any additional wells. But that said, I don't want to rule out that we would never drill any additional 80-acre wells as pilot wells, and that's one of the reasons why we are asking for what we are today.

But the way we are currently looking at this, Mr. Examiner, and with the model that we've built, these nine wells should fit the technical needs that we have at the moment.

Q. So you don't anticipate drilling any additional wells besides these?

A. Not at this time I don't, no, sir.

Q. Well, I guess I don't understand why you want to expand and allow for an administrative process to drill additional wells.

A. Well, for a couple of reasons. One is, as we drill wells and we test them, invariably we get surprises. The reservoir is not nearly as homogeneous, I know, as what I thought originally. And so as we drilled the first six wells and acquired the data that we did, it filled in some voids in our technical knowledge. But it also opened up a few surprises too.

And so the natural evolution of the pilot program is such that you're acquiring data that does fill in the gaps, but it's also raising new questions and new issues, and that's where we're at today.

The first six wells did very definitely address some of those early issues, answered some question, but it raised other questions. And so that's why we're asking for the nine additional wells.

Now, when we drill and complete those wells and test them, there may well be some additional surprises, given that the reservoirs are somewhat heterogeneous and there are some issues there that you uncover every time you drill and test a well.

But I'm not prepared to give you a hard and fast number of wells beyond these nine. This is the limit to what I know and what I feel like we're prepared to ask for.

Q. I guess one of the purposes of the project is to gather Dakota data which maybe can be used on a much larger scale across the San Juan Basin to maybe expand at a later time the Dakota to 80-acre within the whole Basin. Do you anticipate after these nine wells are drilled that you'll have that information that you need, or to go that way?

A. I do. And in fact, I think that's a very important point to be made here, and that is, while we just operate this one federal unit and this is the only pilot that we have at this time, Burlington is a partner in our unit, and we are also partners in a good many of their federal units. And there's quite a bit of interest here in the Dakota development on 80-acre spacing.

So if you will, this will be a data point not only for Conoco but for industry in general, and certainly for Burlington. And I fully anticipate that they'll use this data. They have all the data that we do.

And so looking at it on a little more global basis, it's an additional data point that we can all use.

Q. I believe you testified that you were sharing some of this data with the various working interest owners in this unit?

A. Yes, sir, I have already.

Q. Okay. Is there anybody else outside the unit area that has requested any information or that you're sharing information with?

A. There is one party, BP Amoco, who operates a number of the wells, leases, to the west of our unit and to the north, and they very much have an interest in what we're doing. And being a large Dakota player themselves, they've expressed a lot of interest in what will happen here and the data that we've acquired. So BP Amoco is definitely interested.

Q. So have you shared some of the data with BP Amoco?

A. Yes, sir, we have.

Q. And I assume that Conoco is willing to share this information with other operators that may request it?

A. Yes, sir.

Q. And when you say production performance was favorable, I assume that that means that you can economically go forth and drill these wells, that you feel you can at this point?

A. We feel that we can at this point, yes, sir.

Q. And you state that, overall low reservoir quality present. Is that pretty much the same, Mr. Shannon, in each of the intervals, or does it vary?

A. It definitely varies. The lower Cubero is extremely tight. There is definitely a gradation in permeability and porosity among each of these sand units, and we saw in the lower Cubero lower permeability. That's the bad news.

The good news was, in the lower Cubero, that's where we saw some of the fracturing. But there very definitely is a gradation of properties from zone to zone. That said, none of the three would strike you, looking at the core, as being extremely good reservoir quality rock, compared to reservoirs that we produce elsewhere in the world. In all three cases the sands were very tight. Of course, we knew that going in, this just further proved that.

Q. Okay, which is evidenced, I guess, from the pressure that you got, the average of 2900 pounds in the lower Cubero would indicate it's more tight than the other ones?

A. Absolutely. However, we did see a little depletion in the lower Cubero, so we know we are producing some gas from the lower Cubero. But there were a couple of wells, even in the lower Cubero, where we saw 3200-some pounds, and that is virgin pressure. So obviously in those wells there was no depletion at all.

Q. Is it the Paguate? Is that present in this unit?

A. Yes, sir, the upper Cubero and the Paguate are synonymous.

Q. So that's grouped into the upper Cubero?

A. Yes, sir. Mr. Glaser will be up, I believe, next, so he can address a little bit of the nomenclature on his hands, but the upper Cubero is the Paguate.

Q. Okay. Now, this is the range of pressure that you've seen in these wells, 2400 to 3200?

A. Yes, sir, those were the highs and the lows of each one. And then the averages that I quoted are simply the arithmetic averages.

What I was attempting to do with this particular exhibit was just to give you a sense of the amount of depletion that we saw in each zone. Some wells we saw more, some less, but these are definitely the upper and lower ranges for each one.

Q. Say, for instance, in the lower Cubero where you have a pressure of 2400 p.s.i., can you attribute that to -- was that in an area that showed more permeability or more fracturing?

A. It would have to be. I don't know any other reason why that might be the case. Now, there is variations in the thicknesses of the sand, so in some cases you've got just more sand contributing to the production, so some of it could be due to that. But it was the lower Cubero where we saw some of the fracturing as well, and that could account for some of it.

Q. The --

A. Some of --

Q. I'm sorry, go ahead.

A. I started to say, just some of the depletion that we saw, the lower ends of the lower Cubero, could be due to that.

Q. Did that reflect in your production rates, say, the lower-pressured intervals? Were the wells less productive?

A. I don't recall. I don't recall which well specifically had the 2400 p.s.i.

Q. Did you test these zones separately?

A. No, we didn't, and that's a point maybe to tie back to your last question. The wells when we tested them, you know, production tested, all three zones were open at that point. So we did not know how much production was coming from, say, the Twowells versus the upper Cubero versus the lower Cubero.

One well, we did run a spinner survey, and that being the 225E which I mentioned earlier. But other than that one data point, I could not tell you what percentage was coming from each one of the three zones.

Q. Okay. You don't have a range of production on these wells like you did on the pressure. Are you generally seeing production numbers that are in that short, close range?

A. Fairly close range. If you look at Exhibit 10 again, most of the wells with that one exception, seem to level out around 500 MCF per day. We did have a fairly wide range of initial potential rates in this first few days. We had one well there, or two wells, actually, that tested over 2 million a day in the very earliest periods that we had the wells on test.

One well, the 219M, was quite a bit less. The logs from that well indicated less sand, so there's a direct tie there between sand thickness and the rate. But they did seem to cluster around that 500-MCF-a-day rate.

Q. And they've pretty much stabilized at that rate?

A. Yes, sir.

Q. And these wells are currently downhole commingled?

A. Each of the six wells is downhole commingled with the Mesaverde.

Q. Once you downhole commingle them, can you still obtain production data from these wells that you think is accurate?

A. No, because the way our wells are completed, the tubing is run down through the Dakota. And in order for us to do what you suggested, we would have to have the tubing landed above the Dakota so that we can run a spinner survey or something to go back and actually allocate or see what the production was from each zone.

I'm not saying that would be physically impossible. That is possible. But the way we complete our wells, the bottom of the tubing is too deep in the Dakota to do that.

Q. So do you think, from these six wells, anyway, that you've already gathered the data that you need in terms of pressure and initial production and things like that?

A. In those areas and under that scenario, yes. Given the scenario and the technical needs at the time, yes.

Q. In the nine wells that you propose to drill, those will be commingled in the same manner?

A. In the exact same manner.

Q. Okay. How long a period before the well is commingled, after it's drilled?

A. Well, in this case, obviously we went all the way out to 200-some days. I again would like to see us test at least 30 days, and preferably longer than that. I felt that obviously if there were any abnormalities, boundary conditions, we would have seen it fairly early on.

But again, the rock being as tight as it is, we would have to put them on test for months if not years before you would reach where they're declining at an exponential rate, and we're not prepared to do that. But if we could at least test them again for 30 to 60-some days as a minimum, I would be happy with that data.

Q. Is that in your control?

A. We're a company of 15,000 employees. Yes, I can recommend to our team that we test them for that length of time.

Q. Three of these wells that you're planning to drill in particular, it looks like they crowd the outer boundaries of the section there. Well, two of them anyway.

A. Yes, sir.

Q. Do you know why those had to be drilled specifically at those locations?

A. Yes, sir, I do. The situation for those two really is the same situation in all the others, and that is, given where the parent well was drilled and then the first infill well was drilled just did not leave space to locate them anywhere else. We looked at that very closely, tried to locate them where they would be standard or orthodox locations.

And also there's going to be an exhibit in Mr. Glaser's presentation, you'll be able to see the topographic nature. Some of these locations fell in a draw or a creek, and so we had to move them to where you're seeing them here. And I think when you see that topographic map, that will be a little more clear to you.

We did go to extraordinary lengths to try to locate them elsewhere, but given those conditions, we just could not.

EXAMINER CATANACH: Okay. I have no further questions.

Are there any other questions of this witness?

Mr. Chavez?

MR. CHAVEZ: Thank you, Mr. Examiner.

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Shannon, did -- What information did you miss gathering, or did you miss any information from the first pilot wells that you drilled, that you need to get off of new wells?

A. Right, the data that we set out to get initially a year and a half or so ago, we obtained. There's no question about that. The production tests, the pressure data, the core data, log data that we set out to get, we obtained. So there's not any data, *per se*, that was part of the original objective that could not be obtained for any reason. So we did acquire the data.

As I explained a while ago, it's one of those things, as you acquire more data and you acquire more information, it seems to raise more questions. And so that's kind of where we're at today. But there's no missing data, *per se*, that we could not get from those six wells due to mechanical reasons or anything like that, no.

Q. So you're not going to be drilling these new wells to gain any data that was missed, is what I was trying to get at?

A. I'm sorry, yes, that's correct.

Q. Did you get data that was different than what you anticipated getting?

A. There were a few surprises.

Q. Like what?

A. Well, for one thing, I would not have predicted these production rates that we obtained. Another thing is, when we had our first hearing, we were prepared to go in and get pressure data, but it would have been a single pressure data, which is what we thought we were going to get.

As it turned out, we actually got it zonally. And so we learned a lot about what the pressures were, not just a bottomhole pressure but bottomhole pressures by zone, by well. So there was some additional data there that I did not even anticipate getting, but we got it. And so there was some knowledge gained from that.

Q. But was it different from what you anticipated that you would get as far as those pressures?

A. I did not anticipate that we would see as much as 3100, 3200 pounds in some of the wells, I suppose. I also personally did not expect that the reservoir would be, in some cases, as heterogeneous as it is. So I personally had a few key learnings. I don't know that I could speak for my team on that, but I personally had a few learnings.

Q. And the flow rates, you said you didn't anticipate that they would be that high or that sustained?

A. No, sir, I didn't. And the reason for that is because, looking at the parent well and that first daughter well in most of those GPUs, I would not have thought that a third well would have found those kinds of rates that we did.

So maybe that's more of a testimony for a -- the completion engineers, the production engineers, who did a very fine job in completing the wells.

Q. Well, that is my next question, is, did you compare the completions that were done on these pilot wells to what had been done on the original wells, to see how that might have made a difference in the flow rates that you achieved?

A. I personally did not. I do know this, the production engineers spent a lot of time looking at the very best possible way to frac each well, and we landed on using slickwater fracs. And maybe that's the key, I don't know. But I know that we did use filtered completion fluids, which is something that I know we haven't done in the past.

Q. I'm sorry, what kind?

A. Filtered completion fluids, and just did a splendid job of perforating and fracturing each well.

And then, given the fact that we knew we were going in and having to get pressure data, we knew we had to have a very clean wellbore to start with. So maybe that added to it as well. But we were -- I know I was very pleased with the rates that we got, just based on what I knew about the Dakota.

Q. Okay, would you give some type of comparison to what you thought, they were twice as much as you thought or 50 percent more than what you thought you'd get?

A. At least a good 25 to 50 percent more than what I thought we would have gotten.

Q. And if you were able to determine by studying these completion techniques that that was attributable to the completion, what would that do? Instead of a change in the reservoir itself, how would that change what your current conclusions are?

A. Right. For one thing, we're still developing on 160s in a few areas in the unit. And we are using the key learnings from the completion technology and the completions that we used in those first six wells, onto wells that we're drilling as 160s. So there's a lot of learning that takes place, and maybe this should be expected, that in a pilot program you learn, but you transfer that pretty quickly to your ongoing operations.

And I see that going on now with our current completions.

Q. The pressure tests that you ran, you said you did not determine any boundaries, so these were long-term shut-in -- pressure buildup tests?

A. Right, they were, but I'm not sure what you're calling "long-term". Actually, they were quite short in nature, three days or less. And that was possible because of the way the wells were configured when we completed them. We used downhole shut-in devices, we used downhole gauges. We also did not frac the wells prior to running these pressure tests.

So we intentionally configured the wells and used the methodology so that we could get the pressure data quickly, meaning three days or less in some cases.

Q. So the shut-in pressures that you're reporting, they're estimated or calculated from the pressure buildups that you ran?

A. Yes, sir.

Q. What was the highest pressure that you -- or what were the pressures that you achieved in those three days, the actual pressures at the gauge?

A. In a couple instances, in the lower Cubero especially, we saw fairly close to 3000-some pounds, as I recall. Maybe Mr. Boneau might be able to speak to this, because I don't recall on all the cases. But the lower Cubero, being as tight as it is, we saw high pressures pretty quickly on those tests.

I should add that we had a few problems with the lower Cubero because it did communicate with the upper Cubero behind pipe. It wasn't an issue with our completion so much as it was, maybe, outside of the casing. But the data that we had and the data that we know was good, we saw, as I seem to recall, upwards of 2900, 3000-some p.s.i. But I can't recall exactly in each case what it was. I can get that data for you, though.

Q. I don't need it, I just wondered what they were for this purpose here.

Did you ever encounter areas where you would meet the boundary where another well was draining, say the boundary of a drainage area for a particular well? What did you encounter there?

A. We did not see any interference that I'm aware of on any of the buildup tests. And you know, I might have been surprised if we did, given how tight these reservoirs are. But we didn't see any that I recall seeing.

We did see in a couple of cases fluid in the wellbore where water had fallen back -- presumably water had fallen back in the completion, inside the tubing, and we did -- so we did see some of that on the buildups. But I don't recall seeing interference like from an offset well *per se*, no.

Q. In your selection, selecting these locations, I'm curious about one of the issues that you called -- you said where you picked an area where some data already exists, which was number four in your criteria.

A. Uh-huh.

Q. If data already exists there, why wouldn't you go somewhere else to get some new data to have a larger view of your reservoir, of the unit?

A. Right, we looked at that, and in fact we looked at a number of different scenarios where we would locate our pilot expansion wells in and around other pilot wells, as well as areas where there were no pilot wells. And the 225E -- and Mr. Boneau will be discussing the model here momentarily, but the 225E offered us an anchor point, if you will, where we could tie log data, production data back to a well where we had control in the first place, being that 225E. So we're building on a database that was already established.

If we went off into a different part of the unit where we had no data, that would be educational, I agree. That would be good to have that information. But it wouldn't be building on something that we already had in place, and I think that's what I'm trying to say here with the 225E.

By locating these wells around 225E or one of the other pilot wells, but preferably the 225E, we're kind of building on the knowledge that we have. And with that we'll be able to better refine our model and have a lot of confidence in what that model would be telling us.

Q. As you were gathering data, were you putting it into your model?

A. The effort was ongoing. We had -- Mr. Boneau was doing the modeling concurrent with the data collection. We did not want to wait till all the data was acquired before he started doing that. And he can speak to that here in a bit, but that was an ongoing process.

Q. So as you were ongoing, adding data to your model, what did it tell you to anticipate as far as your pilot project was going on? Did you find that your model was pretty much hitting what you anticipated?

A. Can I defer that to Mr. Boneau? I think he would be better at answering that question than myself --

Q. Okay.

A. -- if that would be okay.

Q. Well, I had another question, you can tell me whether I should wait for him also. As you were looking at production, did you compare that to your model?

A. Yes, absolutely, and --

Q. Okay, and will he testify to that?

A. Yes, and I can say a little bit to that.

The original model was fairly simplistic, and it suited our needs for the time. But with the additional data and the additional information, you know, we have a different -- you know, we can calibrate our model with that.

The original model, as I understand it, predicted lower rates. It had lower rates than what we actually found. So perhaps Mr. Boneau can discuss that a little bit.

Q. Okay. Now, as you build your model or calibrate on the data you get in this small area, isn't it just -- I'm curious how that would help development, because the density of your pilot project here, it seems like it fills the area, you're fully developed there on 80s when you're done, so what good is that model that you predicted for the rest of the unit?

A. I think qualitatively is what we're getting at here. This area that we're looking at around the 225E is kind of an average area, and it's an area where all three Dakota sands will be present, so it is a calibration process.

And again, I think Mr. Boneau might be a better witness than I am, as far as explaining how the model will be used in other areas. But we've discussed that and feel pretty confident that we'll be able to do that. But I think I'd like to defer those questions to Mr. Boneau, if it's okay with you.

Q. Okay, I'm going through your Exhibit Number 12, and your second objective is to test economic viability. What are the criteria that you would use for economic viability?

A. Okay, simply stated, production rates. We already have, obviously, a pretty good handle on cost, on the cost side of the equation, so testing the economic viability is very similar to what it was with the first six wells.

So it's a simple economic evaluation, given the rates that we're going to see with these nine wells and the costs that we would anticipate drilling a Dakota single-type completion. That is a test of the economic viability.

Q. Okay, you had mentioned, in your answer to Mr. Catanach, that once the wells would be downhole commingled with the Blanco-Mesaverde Pool, that you would be losing accuracy of data. I forget exactly what your statement was. But how can you apply that to the issue of economic viability?

A. Right, I think the question concerned testing the production from each of the three zones, is what I heard Mr. Catanach ask. And my response to that is, the way we complete our wells, that wouldn't really be possible, because the bottom of the tubing is set too deep in the Dakota to enable us to do that.

Now, as far as the economic viability, we're looking at these -- in this instance, stand-alone Dakota completions. What would it cost to drill and complete a

Dakota well, and what kind of production rates can we expect from the Dakota? And that's what I'm talking about here with the economic viability.

In real-world sense, what we actually do is, we add the Mesaverde to the Dakota. That's the way we've completed our wells for the last two or three years, and that's what we're proposing to do with these nine wells.

So I can see there's a little disconnect there with that, but that is our thinking, at least.

Q. In looking at your Exhibit Number 1, I looked at that and I was able to count within that exhibit 18 undrilled infill locations --

A. Right.

Q. -- within -- not including the buffer area, but in the buffer area there were 14 more, for a total of 32 undrilled Basin-Dakota locations within the unit.

A. Right.

Q. Now, earlier you stated that you wanted to select these locations to calibrate the data, and in looking at these numbers of undrilled infill locations, I'm wondering why none of those could be used and why there's a necessity to concentrate so much in one area and not drill those others?

A. Okay, that's a very good point. First off, we need some additional maps here to answer your question, and you're going to see them here momentarily, Mr. Glaser's testimony.

There's a part of this unit, namely the south part of the unit, where the Dakota deteriorates. And that area, obviously, we still have some ways to go just drilling 160s. And that's why you're seeing some of these open 160s.

Also, we have an ongoing program of drilling on 160s now. We have a rig drilling in 28-7 as we speak, drilling Mesaverde-Dakota wells on 160s. So not all the locations that we intend to drill on 160s are here yet. If we could have done this three months from now, you would see more dots on the map. So we're getting there, I guess, is what I'm saying.

Q. At this time are you gathering this type of data to calibrate your model in those areas, from those 160s that might be helpful for later -- if you anticipate 80-acre development there?

A. We do in some cases. It just depends on the situation in the well and where it's located. We do run cased-hole logs, at least, on every single well. And of course from those, they're not as quantitative, you know, can't be used as quantitatively as an open-hole porosity log could. But we are running cased-hole logs in each case.

We have been completing each of these wells in the Dakota and producing them as a Dakota sand well, at least initially, for 30-some days, if not longer. So we are acquiring data, even in those 160 wells.

Q. But that's not any different than your regular completion that you've just described? You're not taking individual strata pressures --

A. No.

Q. -- or not doing any coring or anything like that on those 160s in other parts of the unit, are you?

A. We are not. And we've discussed that, and it's just a matter of, again, what our objective is with each well and where it's located and...

Acquiring data -- I should add that acquiring data, especially bottomhole pressure data zonally, is a very expensive, very difficult thing to do. It's not a very common procedure at all. And while it does produce good data -- and, you know, we're very interested in acquiring pressure data, obviously, and will continue to do so, certainly, in these next nine wells. Acquiring data zonally, even in a pilot well, is extremely expensive, and I'm not proposing that we do that.

We acquire data that we -- as I mentioned to you earlier, the production test, the cased-hole logs, but we're not coring. And I don't anticipate coring any additional wells, and certainly not acquiring pressure on a zone-by-zone basis.

Q. So on these nine wells, you're not going to be acquiring this data on a zone-by-zone basis?

A. Not on a zone-by-zone basis. We will be getting bottomhole pressures, though, by just running in with pressure gauges and testing for the lowest pressure that we see, which indicates the greatest amount of depletion. And based on the data that we've already seen, that's probably going to be in the Twowells.

But I want to leave that kind of open, because we're still discussing that to an extent, but I don't foresee taking zone-by-zone pressures.

Q. So then I'm confused. You say you want to calibrate your model better, but you're not going to be taking the same quality of data that you had on the previous pilot wells, on these nine that you propose; is that correct?

A. That is correct. And if it would be okay, if you would like to defer the model calibration and the data for that to Mr. Boneau, because he's going to be speaking to some of that. And if your questions are still unclear at that point, then we'll try to address this question.

Q. Given that you're not really -- It sounds to me that Burlington's not interested, really, in getting the data to develop or look at the potential for 80-acre development in other parts of the unit. How will this data concentrate in this one area, be a benefit once it appears to be fully developed with your pipeline?

A. If I understand your question, you're asking how will this apply to other parts of the --

Q. Yes, it sounds like, from your selection criteria that you used and your lack of apparent interest in gathering data outside of that area while you're currently drilling wells in the other parts of the unit, that you're not really that interested in looking outside of that area right now for development.

So from that, it leads me to believe that this pilot project -- or it leads me to think that this pilot project may basically complete your 80-acre development within the unit.

A. It doesn't complete the development. I don't want to mislead you into believing that we're not interested in knowing what the rest of the unit will do under 80-acre development. We're taking step by step by step. And the data that we are acquiring from these wells, albeit quite a bit greater than what we would normally get in a development well, is good data to acquire, for what we're trying to accomplish.

The development wells that we're drilling now, the 160s, we're acquiring data in those wells. We are getting log data and production data in each one of those wells, and that is data that can be used in our reservoir model.

Q. But that's only data you started with before you had the pilot project to begin with, wasn't it?

A. Yes, yes.

Q. So it's really not any different than your normal operations?

A. No, these wells will have -- If I understand your question, these wells will have pressure data that we normally would not be collecting in a development well. Did I answer -- I'm sorry if I missed --

Q. Okay, so you will be collecting more data than you would normally collect?

A. Absolutely.

MR. CHAVEZ: Okay, I'm sorry, I was misunderstanding your answer.

I think that's all I have, David.

EXAMINER CATANACH: Mr. Chavez. Any other questions of this witness?

MR. KELLAHIN: Yes, Mr. Examiner.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Let me follow Mr. Chavez's analysis here, Mr.

Shannon. Forget your nine pilot wells right now.

A. Okay.

Q. And let's look at areas where we have four wells to a section.

A. Okay.

Q. Those will be areas where, under the current rules, you're fully developed, right?

A. That is correct.

Q. In those sections where you have less than four wells per section, there is an opportunity to drill additional infill wells?

A. That is correct.

Q. All right. The difference between those opportunities and what you achieve with the nine additional pilot wells is this, that by drilling at a density greater than four wells per section, you increase a density where it is, in fact, an 80-acre density; is that true?

A. That is true.

Q. And with those actual data points in the reservoir, then, you can calibrate and test your model with actual data as to what will truly happen within the scope of this study area?

A. Yes, sir, that is correct.

Q. That would be substantially different than data you derived by drilling the rest of the currently approved infill wells?

A. That is correct.

Q. Is that of importance to you?

A. That is of extreme importance to us.

MR. KELLAHIN: No further questions.

EXAMINER CATANACH: This witness may be excused.

TERRY J. GLASER,

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. Glaser, would you please state your name and occupation?

A. Yes, my name is Terry John Glaser. I work for Conoco in Houston, Texas, as a geologist.

Q. Mr. Glaser, have you testified before the Division on prior occasions?

A. No, I have not.

Q. Summarize for us your education?

A. 1978 I got a BA in geology from the University of Wisconsin, Milwaukee, and in 1979 hired on with Conoco. I've been with Conoco ever since.

Q. Are you currently one of the division geologists assigned to the pilot project for studying the increased density concept for the Basin-Dakota within this unit?

A. Yes, I am.

Q. And we're about to look at your geologic analysis, presentation and conclusion?

A. Yes.

MR. KELLAHIN: We tender Mr. Glaser as an expert petroleum geologist.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Before we start that, let's bridge the gap, if you will, by having you identify for Mr. Catanach Exhibit Number 15. What is that?

A. Yes, Exhibit Number 15 shows the same portion of the 28-7 unit that we propose pilot expansion, but this time you see the topography along with the wells in that are.

Q. All right, the color-coding of the wells follows the color-coding and identification for this exhibit as we see in Exhibit 1?

A. Yes, it does.

Q. The parent -- or the original pilot well on this display is the well in black?

A. Number 225E, yes, sir.

Q. Yes, sir, and the proposed expansion pilot wells are those wells in yellow?

A. Correct.

Q. All right. It's your understanding that these wells satisfy the conditions of surface use, and that they're all properly available for approval?

A. Yes, they are.

Q. My question for you as a geologist, sir, is, do all of these locations satisfy you from a scientific position as being an appropriate place in the reservoir to have a data point?

A. Yes, they do. Each one of these wells will see the three subunits of the Dakota that are our producing reservoirs present, and in a pay scenario that we are contributing, that gas is being contributed from these reservoirs.

Q. All right. I know Mr. Catanach is familiar with how Burlington and Conoco and others subdivide the Dakota, but to give us an illustration we can utilize right now, let's have you turn to Exhibit 16 --

A. Yes.

Q. -- and do that for us.

A. Exhibit 16, that's the type log, and it happens to be from the 225E, which we are keying our pilot expansion off of. It shows the entire Dakota interval from the Greenhorn above the Dakota to the Morrison below, and the subunits of the Dakota which we have correlated across our unit, and which are the same units that Burlington correlates in their areas.

Starting from the bottom, we have subunits of the Burro Canyon, Encinal Canyon, which we find not productive in the 28-7 to date. The lower Cubero is our first developed reservoir in here, and the yellow is the net effective pay that I have drawn from this type log and from the other logs in the Dakota penetrations in the 28-7 and surrounding area.

If you notice, the lower Cubero is a very changeable unit. It is very laterally inextensive. It is a fluvial system, dominantly -- tidal-dominated fluvial.

The next unit that we come to is the Cubero. This is the question that you asked, Mr. Examiner, before: How do the Cubero and the Paguate correlate? This is our correlation, and I believe this is very close to what Burlington correlates the Cubero interval with. That unit is extensive, the Cubero is extensive across the Basin. At least across our 28-7 Unit, it changes by just a few feet. It is one of the better producing units within the Dakota in our area.

The next unit is the Paguate, and this is where the changes take place. On the west side of our 28-7 Unit, the Paguate begins to develop into reservoir-quality rock, but very, very thin in existence. In this area it is not reservoir-quality rock. And as you move to the west, the Cubero loses reservoir-quality rock. So they kind of take the place of each other as the main reservoir. But in the 28-7, the Cubero is the main producing reservoir compared to the Paguate.

Then you see a marker bed which I used for our datum for hanging any stratigraphic cross-section on, and that is a very flat depositional unit over the entire 28-7 Unit, which I can correlate stratigraphic stacking packages of the intervals in the Twowells and in the Cubero and lower Cubero.

Above that, the next highly productive interval in the Dakota is the Twowells, and that is fairly blanket in character over the northern portion of our unit. It does show some complexities in the northern portion of the unit, above this blanket sandstone member. But typically, it is one of the dominant reservoirs in the 28-7 northern portion of our unit.

Then above that you go into a deep-water shale deposit known as the Graneros/Greenhorn, and then you're completely out of the section.

Q. The team as selected to increase the density around the 225E well.

A. Yes, sir.

Q. That is one of the original pilot wells for which we have lots of data?

A. Yes, sir.

Q. And the concept, then, is to increase the density around this wellbore to true 80-acre density --
A. Yes, sir.
Q. -- so that you can test the hypothesis as to how much more additional drilling can be supported on whatever density level for the Dakota?
A. Yes, sir.
Q. In this area of the additional expansion drilling, do we have all three layers available for testing?
A. All three layers are found productive in this area.
Q. Let's see how these layers are distributed throughout the unit in a general way, and I assume you've done all that kind of thing?
A. Yes, sir, I have.
Q. Let's take one example, and if you'll look at Exhibit 17, we'll use that as our locator. That's the line of cross-section for your stratigraphic cross-section, right?
A. Yes, this is the cross-section A-A', south-to-north cross-section over the 28-7 Unit.
Q. All right, let's take a moment and unfold Exhibit 18, which is, in fact, that cross-section. Okay, I don't want you to give us a detailed education in the cross-

section, Mr. Glaser, if you'll just give us the executive summary --

A. Okay.

Q. -- what's the major point?

A. This is a cross-section from southwest to northeast, across the 28-7 Unit. And it clearly shows, again, the yellow is net effective pay that I have picked through the Dakota intervals.

And the lower Cubero, as you can see on the left-hand side of the cross-section -- it clearly is indicated -- is a highly changeable unit. It changes laterally and vertically in section. As you scan over the unit, you can see how variable that fluvial system is. And possibly that's why we see higher pressures in some areas and less in others, depending on the correlative sandbodies between wells.

The next unit is the Cubero. This, as you look across the entire cross-section, you can see a fairly uniform feature, about 20 to 22 feet of average reservoir-quality rock.

The datum again is indicated in the black line. This is a very, very good correlation marker across the unit, one that I've picked to correlate this cross-section.

The Twowells is one of the more interesting packages, along with the lower Cubero being very laterally inextensive. The Twowells, in the northern portion of the unit, is a very, very dominant reservoir. As you go to the very southern portion on the left-hand side, you can see the net effective pay in the yellow goes down to zero. You're basically dealing with a non-reservoir rock in that area. It is in this area that the Dakota is very poor in production and can be subeconomic.

And also, as you can see in the northern portion of the cross-section on the right-hand side, above the red line you have a little stacking pattern that does not correlate to the main body of the Twowells. It is very -- highly variable in extent with the individual wells in the northern portion of the unit.

Q. All right, let's go and see how each of these layers is distributed throughout the unit, and I assume you're prepared an isopach of each of the layers that will give us a visual illustration of how the thickness is distributed?

A. Yes, I have.

Q. Let's go through each of those in a summary fashion and have you identify them for us, starting with Exhibit 19.

A. Yes, Exhibit 19 shows the lower Cubero net sand isopach map. It is five-foot contour intervals, the yellow being the thinnest, the dark orange being the thickest, yellow being zero to ten feet of thickness, the dark orange being greater than 80 feet in thickness in some areas, and typically between 45 and 80 feet is the darkest orange.

Again, the lower Cubero, you can see how changeable the isopach is throughout the entire 28-7 Unit, and highly variable, highly inextensive from well to well, and that's why you see such a variance in isopach footages.

The next exhibit, Exhibit Number 20 --

Q. Before you leave that one, let me understand a point on Exhibit 19. The area that is to be subject to the increased density for the expansion is in, generally, 34 and 35?

A. 34, 35 and slightly in 27, yes.

Q. Just a quick visual look at this isopach, it would appear that you have the opportunity to test a rather broad range of thickness within that expansion area.

A. Yes, the lower Cubero will again exist. And this, again, is highly variable. Each well will probably show quite a bit of variation. So trying to predict this unit is very difficult. But we will have thicknesses, most likely, from 21 to in excess of 60 feet in thickness.

Q. Would that be a reasonable range in which to test an area such as this for a pilot that then can be translated in some fashion as to whether or not you drill increased density wells elsewhere in the unit?

A. Yes, it could be.

Q. All right, let's take a look, then, at the next layer. If you go to Exhibit 20, tell us the color code here so we understand the contour difference.

A. Yes, this is Exhibit 20, this is the Cubero net sand isopach map, again on five-foot contour intervals, the yellow being zero to ten feet, the orange colors in excess of 20 feet.

Q. All right, and then finally Exhibit 21. What are we looking at here?

A. Exhibit 21 again, this is the Twowells net sand isopach map. The contour intervals -- five-foot contour interval from zero to ten feet in the light yellow and in excess of 40 feet in the dark orange.

Q. All right, is the geologic concept here one where you as the geologist would stack the three layers, find locations where you optimize the opportunity to have the greatest thickness in all three layers?

A. Yes, I would.

Q. And when we look at Exhibit 21, down towards the south and southwestern portion of the unit, the Twowells sand is simply not there.

A. Yes.

Q. Does that help you explain why the southern portion or the southern third of the unit has not yet seen drilling to the current density?

A. Yes, it is. Again, as I said before, the Twowells is one of the dominant reservoirs. Without the Twowells, we can find subeconomic wells.

Q. In addition to doing this work, Mr. Glaser, you've also helped Mr. Boneau in providing the geologic data that he's inputted into his reservoir simulation?

A. Yes, I have.

Q. And that's been done independent of this stuff here, right?

A. Yes.

Q. All right. Let me ask you this: Once the reservoir simulator experts and all the reservoir engineers get through doing all this stuff, and they run this model and it forecasts some things that will happen for you, what do you as a geologist see that you'll get, that will allow you to decide where to increase your density in the unit?

A. The net sand isopach maps are probably one of the major inputs to any geologic reservoir simulation, modeling, and without these -- without the modeling, you can predict, you can estimate what the gas in place is, and typically done for net sand isopach maps, to dictate where the best areas will be.

But it doesn't have the luxury of having a detailed model to calibrate off of.

Q. For example, you could use a net-pay map, calculate original gas in place, think you've got a great place to drill it, and find the gas in place is not there?

A. Yes, exactly.

Q. By a substantial magnitude of change, right?

A. Yes.

Q. All right, so what do you get out of the model?

A. We get a way to calibrate what the isopach values mean, and be able to take those values, then, and project to other areas that do not have a model, on what kind of gas-in-place estimates we can -- with a fair amount of confidence, being able to relate that back to our reservoir-simulation model.

Q. So if the simulation can be successfully done and further calibrated by the increased density wells, your expectation and hope is that you will be able to utilize that data in a convenient, expeditious way, perhaps by using a net-pay isopach that now has some definitive science behind it, to choose the places where increased density ought to occur?

A. Yes, we hope to be able to extend our knowledge into the 28-7, other areas that we have not modeled, and also into the Basin-Dakota Pool, which will help the whole industry, and at least another tool to use in deciding where increased density may be established.

Q. We often present to the Division an analysis of structure, because that sometimes is important, and sometimes critical.

A. Yes.

Q. Is structure a critical component of what you're doing here with this project?

A. It does not seem to be critical in what we're doing with our project.

Q. Can you illustrate that with Exhibit 22?

A. Yes, Exhibit 22 is a Greenhorn structure map. It is, again, right above the Dakota. And it shows relatively uniform northeast dip, about 50 feet, plus or minus, per mile.

MR. KELLAHIN: That concludes my examination of Mr. Glaser, Mr. Catanach.

We move the introduction of his Exhibits 15 through 22.

EXAMINER CATANACH: Exhibits 15 through 22 will be admitted as evidence.

Mr. Chavez, do you have any questions of this witness?

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Glaser, is there any subtle differences in the Conoco terminology and geology that differ from what the Examiner has heard before, perhaps with Burlington?

A. We are trying to very closely use industry standards on terminology, and I believe what Burlington presented a couple weeks ago to the Examiner, we are very close to exactly what they're correlating their subunits to the Dakota with.

Q. Okay. On Exhibit Number 1 we show that there are infill wells in fully developed Dakota in Section 19 and 20 of Township 27-7, although those are in areas where the Twowells does not exist. Are those Dakota completions in there uneconomic, or are they still economic?

A. Yes, there are wells in this area that are subeconomic, there are wells that are marginally economic in this area. The reservoir changes rapidly, and there is a corridor of what we consider a noneconomic area in this portion of the unit, in the southwest portion of the unit.

Q. Okay, so in your examination of the production records and all, from the Dakota, from these completions, did you find that out to be so that these wells are not going to be economic?

A. Yes, I have.

MR. CHAVEZ: Okay, thank you.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Glaser, let me ask you this. You haven't shown a regional map of the San Juan Basin here, but how does this geology within the 28-7 Unit compare to the San Juan Basin as a whole?

A. The geology -- Each unit changes quite radically as you go from the east portion of the Basin to the west. In the east portion of the Basin, the Cubero and the Twowells are the dominant reservoir. The lower Cubero, in portions east of the 28-7 Unit can be a dominant portion of the reservoir also.

As you move to the west, you lose the Cubero unit. The Twowells unit is not present in the southwestern portion of the Basin. So there is lateral changes that are quite significant from one side of the Basin to the other in all of the three, and possibly more than three reservoir intervals of the Dakota.

Q. It's your opinion that it's necessary to have the Twowells interval present in order to economically drill these wells?

A. Yes, at this time, looking at all the wells in and around the 28-7, the Twowells is a dominant producer for us. And without that, we limit ourselves to a very tight lower Cubero sand that may or not need fracturing to enhance the permeability and porosity for that reservoir.

And the Cubero also has some changes that go on, and it does thin out, according to Exhibit Number 20, it does thin out as you go to the west and to the southwest in our unit. So you put the loss of the Twowells and a thinning Cubero with a marginal lower Cubero that may need fracture enhancement to aid in the production, and you'd get some economic wells in that area.

EXAMINER CATANACH: I don't have any other questions of this witness.

Any other questions?

MR. KELLAHIN: No, sir.

EXAMINER CATANACH: Okay, this witness may be excused.

Let's take a short break here, ten minutes.

(Thereupon, a recess was taken at 2:09 p.m.)

(The following proceedings had at 2:20 p.m.)

EXAMINER CATANACH: Okay, we'll call the hearing back to order and turn it over to Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Examiner.

TRENT BONEAU,

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. Boneau, would you please state your name and occupation?

A. My name is Trent Boneau, I am a reservoir engineer with Conoco in Houston, Texas.

Q. On prior occasions have you testified before the Division?

A. No, I have not.

Q. Summarize for us your education.

A. I graduated from the University of Notre Dame in 1990 with a BS in mechanical engineering, I have an MS in mechanical engineering from Georgia Tech in 1993, and I have a PhD in petroleum engineering from New Mexico Tech in 1997.

Q. What are your current responsibilities for Conoco?

A. I am currently a reservoir engineer working the San Juan Basin, working development aspects and also working simulation aspects.

Q. What has been your participation concerning this particular Application for expanding the Dakota pilot project within the 28-and-7 Unit?

A. I've been the reservoir modeler since we started drilling the pilot wells.

Q. Have you had the responsibility for integrating the additional data that has been developed from the first six pilot wells?

A. Yes, I have.

Q. And are you part of the team that's responsible for choosing the location of the additional nine expansion wells?

A. Yes, I was.

Q. And you're responsible for doing the reservoir simulation for the pilot?

A. That's correct.

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

EXAMINER CATANACH: Mr. Boneau is so qualified.

Q. (By Mr. Kellahin) Let me have you turn to Exhibit 23, and let's refresh Mr. Catanach's recollection about what you mean when you talk about reservoir simulation for the unit.

A. Okay.

Q. First of all, describe for us the model and how you're putting this together.

A. Okay, first of all the computer code we use was Eclipse 100, which is a fairly common product. It's a Schlumberger product, so that's pretty well accepted as an accurate model.

What we did was, basically, we did the simulation in two steps. We took the data from the pilot wells and used it to calibrate our geologic model. And then once we calibrated that model, we're using the simulator to predict how we think the expansion wells are going to do. And that will be what I'll be talking about.

Q. Okay. Let's take Exhibit 23, then, and describe for Mr. Catanach how you built the layers and the grid for the model.

A. Basically, we built a grid that has three layers, and these three layers would be the same subunits that have been discussed, the Twowells, the Cubero and the lower Cubero. We built a variety of models, depending on the pilot well. We built essentially a single model for each pilot well, so we actually had six models. But each model was about 6000 acres. It was a 60-by-60-by-3 grid. So because we had six different ones, there were variations in the number of wells. But basically it was about nine sections, so in general there were 36 existing Dakota wells, four wells per section.

Q. Okay, let's start with the concept in an executive summary of the concept of how the model was configured prior to the first hearing. How were we presenting that to the Division initially?

A. Basically, we were going through with a generic model. We had a -- They incorporated our current geological estimate into a generic model and then said, Well, if we drill generically on a symmetrical 80-acre pattern, we expect this kind of recovery. That was what we brought into the first hearing.

Q. All right. Get approval for the first six wells, those wells are drilled, and you took each one of those or a selected population and redid your model?
A. That's correct.
Q. All right. You selected one of these to study, which was the 225E well in Section 34, right?
A. Yes.
Q. And you ran your simulation with that additional data point and made further forecasts with that, true?
A. That's correct.
Q. What did those forecasts tell you?
A. Do you mean what did they tell us about -- I'm not sure what you're --
Q. What did --
A. -- about the expansion, or what did they tell us about that single well?
Q. What did they tell you about that single well?
A. Basically, it told us that that single well, if you add one single well to nine sections, that well is going to be just about as good as the existing wells there.
Q. All right. How do we take this to the next level, then?
A. Because we're eventually looking at getting to 80-acre spacing, what we'd like to be able to do is actually go and drill on area, on 80 acres, where in the

past we just -- we have wells scattered about the unit, and they give us some data throughout the unit, but they don't really show the interactions between all the wells on 80 acres. And so what we'd like to do, and what we're proposing in our expansion, is to drill something more similar to that, so that we can model that and calibrate our model based on the results.

Q. All right, and to test the hypothesis about what increased density would do and what happens in the real world within the grid side of that study area?

A. That's correct.

Q. All right, let's go to Exhibit 24, then, and have you go back and tell us what this demonstrates here.

A. Well, basically what we did with the pressure data from the first six pilot wells was, we kind of used the model as sort of an elaborate P/Z-versus-cum estimate, to estimate how much gas there was in place and kind of compare that to our geologic model.

So we pretty much went in with the geologic model that had -- and the exhibit here shows what we went in with, which was about 22 to 23 BCF per section, was our original estimate of gas in place. And then we went through and just basically had all the actual wells, the parent and the daughter wells, 320s and 160s, we extracted their actual volumes and tried to match the pressure that we saw in the three layers, in the pilot wells that we drilled. So by that we could calibrate how much gas there was in place.

Q. Okay. Let's turn to Exhibit 25 to show Mr. Catanach what the grid simulation looks like for the 226 well.

A. Okay, this basically shows a 60-by-60 grid. We've got the existing wells in there in yellow, it's a nice -- the coloring is not ideal, but -- and we have the pilot well in the center. So basically we pull all the volumes out of the yellow wells and we see what the pressure is 226 well, and we change the model until we get what we saw in the actual data.

Q. Okay, what happens, then, when we go to Exhibit 26? What are you doing here?

A. It's summarizing what we saw for each individual pilot well.

Q. And what did you see?

A. We saw a variety of gas-in-place per section. On average we saw about 15, 16. 15.7 BCF per section was our average estimate for gas in place. So we saw basically that between -- before the pilot wells and after the pilot wells, our gas-in-place estimate shrunk, based on our pressure observations.

Although our pressure observations, we saw a little depletion, we saw 17-percent depletion as opposed to 14-percent depletion, something -- you know, that type of scale.

Now, basically, underneath the 15.7 BCF per section I have an average from the current updated geologic model. So basically Terry Glaser, the geologist, and I start in the same place, with an old geologic model. I went to update it using the pressure data and the simulator; and at the same time, parallel, he went updating it by incorporating the current logs, getting a better estimate of what log responses actually pay, and he came up with his model, which he already demonstrated.

And you can see if you look at the stuff from the simulation, you get basically, on average, something similar to his answer. And you also get permeability estimates and things like that.

Q. All right. For each of the original six pilot wells, then, you have a grid simulation, you've run the model for each of the six, and they show you calculations of gas in place for each of those six wells. And there's quite a bit of range to that.

A. Yes.

Q. They range from 12 BCF all the way up to 21.5 BCF.

A. Sure.

Q. All right. How do we take this, then, to the next step so that we get a more accurate sense and understanding of what the gas in place truly is?

A. Well, the first thing you have to realize is that when we have a number, it's really based on one data point. It's based on the pressure in one observation well. And errors in that pressure or -- You're basically drawing a line through two points in a P/Z-versus-cum sense, and you don't really -- the second point, the current status when we drill the pilot wells, we're basing a nine-section area on one single well.

And from a pressure-gathering standpoint, we'd like to go get pressure on additional wells within that area so we can further calibrate those estimates and see if our 15.5, for instance, for the 225E, is really accurate.

Q. All right, and you propose to do that, as illustrated on Exhibit 27, in an area which we've previously described as being associated with the current pilot well, which is Number 225E?

A. That's correct.

Q. This would be the illustration in the simulation grid to show where these data points would be inputted into the computer?

A. Yes.

Q. All right. What do you achieve with this that you can't achieve without the additional expansion wells?

A. Basically we will get to see in the real world and compare to our simulation how drilling on 80 acres -- what the results will be. We're going to get data on a finer mesh, and we're going to get production data on a finer mesh, essentially.

Q. Why was the 225E area chosen, as opposed to one of the other five initial pilot well areas?

A. There are a variety of reasons for that. One, our initial gas-in-place estimate was in the mid-range, so we would test what we thought was a mid-range concept.

Two, we have more data there, we have a core in that are, the 225E. Topography allowed us to actually drill fairly easily with only one deviated wellbore in this area, so we could actually drill an 80-acre spacing fairly easily in that area. And I think those are the main drivers.

Q. In this reservoir, with the current database, what parameters or values are you trying to match or simulate with your computer?

A. The main things we're trying to match are permeability and gas in place, and also we want to get more initial rate data, because the rates we've seen from these wells are higher than what we initially forecasted.

And if we have less gas in place, and each additional well appears to be making more than originally forecasted, we have to consider what is the proper development. It changes what our initial idea was of what the proper development was, because we have less gas in place, and it appears that additional wells may be making more gas.

Q. For purposes of this simulation, then, you're matching the production of the wells within the modeled area?

A. And we're going to match the pressures too. We're going to use the pressure from this stuff, from these additional nine wells, to calibrate our gas-in-place estimates along with the 225E, so we can basically see how these locations are being drained by their offsets and see if that corresponds with our geologic model.

Q. Currently, you would be limited in your analysis, because you can only match as to production?

A. That's correct.

Q. And the few pressure data points that you may have?

A. Right, in this model we would have one pressure data point.

Q. All right. With the increased density wells, the additional nine, you now have new points of production and new points of pressure to match against?

A. That's correct.

Q. In order to achieve those matches, what are the values that you're adjusting? You're going to adjust which of your parameters to make that match?

A. Layer thicknesses, primarily layer thicknesses or hydrocarbon pore volume per layer, and permeability of the layers, would be our main match parameters.

Q. The other values would remain constant?

A. We may have to do some tinkering with well completion efficiency and things like that, that we appear to be getting better hydraulic fracturing than we were in the past.

Q. All right. Let's go to Exhibit 28 and look at an illustration of the history match and then the base forecast for this particular analysis. Describe for us what you've done and what it shows.

A. Basically, this shows for this expansion area, the model that was on Exhibit 27, it shows -- the dark blue line shows how we think the model is going to do, the red squares leading up to 2000 show how the model -- how the wells actually performed. So you can see that we have our model performing as the wells actually did perform. And the little red triangles show how our decline curve estimates show how the current wells will produce.

So you can see basically that our model pretty well matches how we think the well is going to do if we just looked at the production data.

Q. All right, let me make sure I understand. On Exhibit 27 you've got the existing wells in yellow --

A. Sure.

Q. -- you've got the initial pilot well, 225E. And then you have imposed into the computer the additional increased density wells you're asking for today?

A. That's correct.

Q. Then you have run the computer and you have matched the production history that's known now for existing wells, and that is displayed on Exhibit 28?

A. Exhibit 28 is only the production of the existing wells, only the wells in yellow. So basically to say what we've known and what we can forecast to this point. Then we're going to try to say, Well, if we add in these additional wells we'll see this.

Q. All right.

A. That's what we'll get to.

Q. By adding the additional wells, then, you can test the accuracy of the forecast shown on Exhibit 28 to see if you need to make adjustments, right? Am I missing the point?

A. Basically we're saying we think we have -- we have matched -- that we are going to have confidence in our model's ability to predict how these wells -- for the model we have, it matches the old existing wells. So consequently we think if the model -- for that model, it will be able to match the current wells.

So basically we're laying the groundwork for showing the incremental advances from drilling the expansion wells. The model right now will match the actual current existing wells.

Q. Okay. And what you obtained with the nine additional wells, then, is the additional data point to then run the model and see how successfully you can forecast what will happen?

A. Yes, we'll be able to compare -- we will have a forecast for how we think the nine wells will do. When we see what they actually will do, then we can go back and further calibrate our model. So we'll look for differences between those two things.

Q. All right, let's see what we think will occur nw, as you've illustrated on Exhibit 29. What are we looking at, and how do we read it?

A. Exhibit 29, basically if you look at the green bar and -- the green line, and everything below it, shows the 52 BCF, and that's how much recovery we think we will get from the existing wells in our nine-section area. So that basically corresponds with the dark blue line in

Exhibit 28.

If we don't drill any increased-density wells, we think that the current wells will make 52.1 BCF.

Q. If you drill the nine additional wells within this grid area, what does the simulation forecast will be the result?

A. That would be the 59.4-BCF number, so we would expect to recover 7.3 incremental BCF in reserves.

Q. The nine additional wells in the grid area will get you 7.3 additional BCF of gas that would not be recovered by the wells in absence of the nine?

A. Actually, that number does include the 225E.

Q. All right.

A. The 225D is included as one of the additional wells. So its ten, actually.

Q. Is there any way to read this display to show what portion of the production would be attributed to rate acceleration?

A. Yes, the dark blue area shows basically what we think the existing wells will produce if we drill the ten additional wells. So if we drill the ten additional wells, they will actually lose -- they'll produce 2.6 BCF less than they would if we did not drill those wells.

So you could say out of -- basically out of -- the difference between 59.4 and 49.5 shows how much EUR we will get out of the ten wells we drill. So essentially the ten wells will recover 10 BCF, but only 7.3 BCF of that will be new reserves. So you could say 73 percent of the production will be new reserves, and 27 percent will be acceleration.

Q. All right, sir. Turn to Exhibit 30 and identify and describe this display.

A. This just shows a typical well forecast, and I basically chose one of the wells that -- There were some differences in the wells. I chose one of the wells that actually made about a BCF, so it was about the average, and it shows high initial rates falling off rapidly and pretty much just shows the typical profiles. It shows a well that will make about a BCF, IP at about 1200 MCF a day and decline off fairly rapidly to stabilize out and produce for 40 years.

Q. All right. The next thing you need to look at is what the economic consequences are of paying for the additional nine wells within the study area, and whether or not 7.3 BCF of new reserves makes sense to do.

A. Correct.

Q. Have you done that?

A. Yes, we have.

Q. Do you have a display that illustrates your conclusions?

A. That would be Exhibit 31.

Q. Identify that and tell us what you've concluded.

A. This is the economics we ran, and it's economics for the entire project, and the project would basically be our nine expansion wells, and it also includes 225E, would actually be for all ten wells.

The things we assumed were a $525,000 well cost, $500 per month operating cost. We assumed a constant price, which was essentially $3.30 per MCF for the quality of gas we think we're going to produce.

The results of that were pretty good economics, with 26 percent return on investment of .42 P/I, 48-month payout. So we think that the economics of the expansion, if we have the correct geological model, should be positive.

Q. All right. Summarize for us, Mr. Boneau, what you think would be the positive benefits of allowing you to expand the project as discussed in this Application.

A. The main thing is, the main benefit would be, we'd like to get an 80-acre analogy. At a certain point we'd like to stop drilling pilot wells and either come unitwide, basinwide, and say, We think we have enough data that we can extract from here to there to there.

What we eventually would be talking would be 80-acre spacing. We're talking about two additional wells per

GPU. And this -- What we're proposing here is actually to go through and do that. We don't really -- We don't have that information.

We basically have drilled wells scattered throughout the unit, testing general properties throughout the unit, and we're now recommending -- and this will give us an idea of what an actual 80-acre pilot will do. We will be able to hopefully calibrate that to our geologic model, then use our geologic model to expand and describe what we think would happen in other parts of the unit.

Q. And decide if it's the right or not, right?

A. Sure.

Q. It may prove to be wrong, you know, but we are at least testing at an 80-acre density to see if in the real world that's going to work?

A. Right. Basically, our first six wells showed us that one additional well per GPU, but essentially one additional well per section, gives us a pretty good well. We want to go out and see, if we put four additional wells per section, what's going to happen. And to do that we need to better calibrate our model and actually go do that.

MR. KELLAHIN: That concludes my questions for Mr. Boneau.

We move the introduction of his Exhibits 23 through 31.

EXAMINER CATANACH: Exhibits 23 through 31 will be admitted as evidence.

Mr. Chavez?

EXAMINATION

BY MR. CHAVEZ:

Q. Yes, you stated earlier that after a while or after some period of time, you would be able to -- when the wells were producing, you would be able then to say, Okay, now we know the model works. How much time is -- That's what I got of what you said. How much time is that?

A. That's going to be -- what we'd like to get is -- The wells seem to produce on similar declines, and if we see an early time production, we think we can forecast late time production. And basically from a modeling standpoint, we can estimate how quickly these wells are going to want to extract gas out of our model.

If we can estimate how quickly, which essentially is a combination of the reservoir permeability and the well completion, and if you then can go and put that in your model and -- basically the well completion and permeability information, you can forecast the interrelation between all the wells.

Q. Well, I understand that, but how long is it going to take before you will say you're done or you've got a handle on it?

A. I think one or two months of production should be enough to say that we can -- we have a similar decline and we're just going to basically, you know, look at scaling it up and down. And within a few months we should have a pretty good idea of what the first few data points are, and then we can just basically -- then we could calibrate our well completion, check that versus permeability and pretty much forecast how that well would do in the absence of all other wells, and then forecast how it would do with all the other wells there.

Sixty days, thirty days.

Q. So have you done that with the existing pilot wells?

A. We have, yes.

Q. And the exhibit that showed your history match, does that include the pilot wells?

A. No, it doesn't, that history match is just for the nine-section area surrounding 225E, and it only includes the wells before 225E.

We do actually -- We have predicted how 225E will do, and this kind of ties into why we're doing the expansion. We can predict how 225E will do if we only drill it, but we want to go through, and we know that it's going to give us about as much gas as the parent and the daughter wells. We really want to go through and see what kind of recovery is it going to give if we drill a well similar to it in every possible location, every 80-acre location.

So we can see that if we have 36 wells, if we add a 37th well it's going to be basically the same as the first 36. But if we go through and we put in 72 wells, as opposed to 36, that's what we want to try to forecast.

Q. How accurate would you say your Exhibit 28 is on the history match for existing wells for your model? Is it, would you say, 99-percent accurate, 95-percent accurate? Do you have a qualitative or quantitative number that you could attach to that?

A. Directionally it is accurate. A quantitative number, it's --

Q. Qualitatively how is it? Great match, good match?

A. It's a very good match. You'll see actually a difference between the two curves at the end, and that's mostly economic limits on our decline curves, some things like that.

The Eclipse -- A reservoir simulator does tend to be slightly more optimistic in tight-gas sands than what you would get on decline curves. And over the long haul, the difference between 3.2-percent decline and 3.1-percent decline adds up to about a -- It adds up to one half of one percent of the production, so you see the difference between -- I think it's a very good match.

The fact that we can actually -- that the model says for the next 20 years we're going to be producing basically what our decline curves say is pretty good, because we've essentially taken the reins off and you let the horse run, and the horse runs for 20 years the way you actually think it will run based on projections from more conventional reservoir methods.

Q. Okay. Well now, you have more than 15 or 30 days on your pilot project. Did you apply the model to those wells, or did you get what you might call a similar match on those wells using the model as it was before you input any changes to it?

A. The big driver, I think, to the early production, at least from the modeling standpoint, is the completion. And if you look at the -- We can get a good sense for what the completion is for those wells, yes. We can use -- That's a difficult question to answer.

Basically, we can take the early production data and say that this well appears to have a fracture, this long, this kind, and it's going to produce -- pretty much, you match the difference in rates between the pilot wells, mostly on the completion efficiency, the skin factor.

So you can use the early data within that, and I have used the early data to say that the skin factor on 225E is this, 226E is this, 135E is this, 234 is this, so I have done that. And then you can say, Okay, that does -- if I change the skin factor, I can match the production.

So if I change the skin factor with the current geologic model for perm, thickness, I can match the production and I can forecast out how it will do. But I've only forecasted out how it will do in the sense that it's the only additional well added to that area. I'm not sure if I --

Q. To what area?

A. To the area that it exists in. For instance, we're going --

Q. 160 acres, 80 acres?

A. Nine sections.

Q. Nine sections, okay. When you get a match like that -- So it's not unreasonable to say that the difference in the completion can be factored into your analysis, the results of your model; is that right?

A. Yes.

Q. Okay. Then when your history matches, or when your model matches, then, the production, factoring in the difference in completion, how good a match is that, that you receive for that one well?

A. It's -- the match -- You basically can vary the completion to match anything. The match is fine, the match is perfect. We don't know how good the fracture is. If I go define the fracture however I want to match the production of the current well, I can match it perfectly --

Q. With a perfect match --

A. -- in almost every case.

Q. What I'm getting at here is, if you have a perfect match, what more data do you need to calibrate the model?

A. I have a perfect match if the geologic model is correct. There are enough variables, if you fix one, you can change the other one if you get a match, but that's all based on the premise that the first one is correct. What we're saying is, we're not sure if the first one -- We have a guess for the first -- the geologic model. You can go, then, change the well efficiency, well-completion efficiency, to match the production data.

But you have to hold one thing constant, and you can vary the other, and you can always get a match. But the problem is, what if this one isn't right? If you change this one, then your completion efficiency is different. There's an interrelation between the two, and it's an iterative process.

So we would like to go back -- the main driver is going to be the -- We think we can say, if we look at a finite production period and we have the right geologic model, we can predict how well this model will produce in the absence of additional wells, with additional wells, et cetera, et cetera. We think -- And basically, if you have the right geologic model and you match the early production data, we think you can say how it will produce from then on.

But we want to go back and calibrate the first step. There are enough variables that you can -- There's an unlimited number of matches for anything, it's an infinite number of possibilities. We're choosing the geologic model constant based on our pressure information, changes of well completion efficiency, until we match the pilot well production.

If I'm not explaining this --

Q. So what you're adjusting, then, is actually your well-completion efficiency?

A. For this geologic model we adjust our well-completion efficiency until we see predicted rates that match the 220-day to 30-day to 60-day rates from our six pilot wells, yes. It's a bit of voodoo.

Q. I beg your pardon?

A. It may sound like a bit of voodoo, but that is -- yes, that is what we do.

Q. Yes. Why are nine wells more important than, say, eight wells or seven wells or six wells or one well within this area?

A. I think the number nine is fairly arbitrary. We think we need a -- I don't think we necessarily know how many wells we do need, but we know that we need more than one data point. I don't know if we know what the upper limit is, and that is -- I think we're leaving that intentionally ambiguous. We think that we need a representative sampling, and we just picked a big enough area that if you drill that area on basically 80 acres, you end up with nine additional wells.

Q. So did you do a statistical analysis to see how your quality of your calibration would be if you used fewer wells?

A. No, we did not.

Q. So conceivably you could go to a smaller area and use fewer wells and still have a model that, as you say, might be perfect?

A. You've lost me on the model-being-perfect part.

Q. Well, you had -- I'm sorry, your match would be perfect is what you had said earlier, not the model.

A. We feel that -- The less data you have, the more possible answers there are. There are enough things that you can change -- If you have one data point, you don't know if changing this one is important or this one is important or that one is important or this one is important. But if you have ten data points and you have to match ten data points, you start to see what's really important.

And that's we're saying, is, you constrain the number of possible answer and the possible realizations if you have more data. If we had infinite data and infinite equations, we can solve for it. But right now we've got a lot of possible variables and one data point. So we have to fix different things and vary others.

But if we have ten data points, we have a much better chance -- if we have what we feel is a significant number of data points, we have a much better chance of having a constrained answer.

Q. When you say "much better", how much better?

A. Well, it should be ten times more accurate.

Q. So --

A. Your error -- Basically, your standard deviation will be divided by ten. So if your standard deviation is -- I think the gas in place is -- the average is 15, and I see that maybe it's 21 or it's 12, and so my deviation is 2, 3 BCF, well, if I go and I have ten data points and match it, you would expect that your standard deviation would be half a BCF, or a tenth of that. It's a sampling, basically, issue.

Q. Would you be able to supply a statistical analysis of that to show the qualitativeness? You just did that off the top of your head. Would that --

A. I mean, I can show that sigma divided by N is -- I'm not comfortable doing that at this point, no.

Q. Okay. Using the current model you have, if you were to extrapolate it to, say, the southwest portion of the unit where the Twowells is nonexistent, would you expect to match the production there with your model pretty closely?

A. Well, we're trying to use our model -- We're trying to calibrate it on Terry's answer in one place, and then we would then go use Terry's answer in the other place, and I can't tell you how that would do.

But we would expect that the geological model, if it fits in one place, the expectation would be that it would fit in another place. And that's primarily due to the fact that we think qualitatively our geological model is correct, but quantitatively it may not be 100-percent correct.

So if Terry's model says it's 20 feet of pay, and he says it's 10 feet of pay here, we think there's really twice as much pay, but it really may be 23 and 11.5. So if we can firm it up here, we would be comfortable going to the other place and saying, yeah, we think that that model would describe the production, would describe what would happen if we increase the density there. And that's the basis.

We basically want an analogy we can transfer based on, pretty much, net effective pay.

Q. So if I understand that correctly, then, if you were to gather data from someplace outside of this small area, the model would be transferable?

A. The concept is transferable. The model, in terms of -- When I think of the model, I think in terms of this layer is this thick, this layer is that thick, this layer is this thick. But we would need to know what the data inputs were at that model. We would need to know the -- at that area. We would need to know how much their wells produced.

Conceptually, I think you can apply the same concept anywhere, that if you could go through and say, I've looked at the logs similarly to the way I looked at the logs here, and the answer there is X and this answer is Y, and we know how Y performs, we can predict how X would perform.

Q. Okay. Given that, given the variability of geology you heard across the unit, wouldn't it be more beneficial, then, to perhaps get data from the other undrilled 32, 34 locations that are existing within the unit in other places?

A. More data is always good. We're looking at drawing a line in the sand and saying, We want an analogy we can apply, but we don't want to actually have to go do a -- we don't want our pilot to be drilled, what we wanted -- to drill 80 acres everywhere, because then, like you said, if we're clearly defining this by drilling on 80 acres, and it only tells us about this area, what have you really done?

We're looking to say, We can take this area somewhere else. And if the geological model is correct here, we're going to assume it's correct there, and we could basically apply it conceptually to the other area. We'd prefer not to drill up the whole unit to prove we could drill the whole unit.

Q. Well, if you were to use the 160 wells, gather the data from the undrilled or partly drilling 160 infill locations --

A. Okay.

Q. -- wouldn't that give you a better quality of calibration for your model across the unit?

A. Yes, it would.

MR. CHAVEZ: Okay, I think that's all I have.

EXAMINER CATANACH: Okay.

MR. KELLAHIN: Follow-up question, Mr. Examiner.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Let's follow Mr. Chavez's line of reasoning. If you go ahead and drill up the rest of the unit on current density, is that going to tell you anything about whether or not you should go to 80-acre density?

A. Not as much, because you're much less likely to see any depletion at 160-acre spacing.

Q. You're not going to know any more than you know now, right?

A. When we originally drilled the second well in the GPU, basically it took a long time to get those wells on line, and so we essentially got bottomhole pressure at those wells, initial pressure with no production, and we saw that there was virtually no depletion, because -- by drilling -- we're drilling actually -- the pilot wells we drilled are -- by being 80s, they're closer to producers, and you actually can see the depletion, and you can use the pressure information.

But if your drainage hasn't got to that point yet because you're drilling 160s, the information -- the only data point you know is, my drainage hasn't got to this point. You don't know that the offset well that produced 2 BCF has drained 20 percent of my production here.

Q. So the additional nine wells will give you an opportunity for data that you can't achieve otherwise?

A. That you cannot achieve by drilling 160s.

MR. KELLAHIN: That's right. No further questions.

EXAMINATION

BY EXAMINER CATANACH:

Q. So once you obtain the data from the nine wells and you recalibrate your model, your reservoir-simulation model, that will enable you to refine the geologic model or to --

A. It will be a give-and-take iterative process between that and the geologic model. It will give us a better sense for how well our ability to predict net pay from the logs -- how accurately we do that, at least from the modeling standpoint, that's -- we will be able -- We have an estimate of what the net pay is by going through all the logs.

But we don't have enough core data to say this porosity, this permeability and things like that. We just have to kind of qualitatively say this is pay, this isn't pay, based on a lot of work Terry's done on porosity logs and gamma ray and correlations.

But yeah, we think that this will kind of scale the geologic model, and the geologic model will scale this, and there will be a give-and-take and we'll come up with a better answer.

Q. So once you have a better geologic model, you can take that and apply it to other areas in the unit?

A. That's the hypothesis, yes. That's the plan.

Q. Well, how do you do that? Do you -- Then you'll have the simulation, you input that data into the simulation in other areas of the unit?

A. Yes.

Q. And you should be able to predict well performance?

A. Right, so we could evaluate different development scenarios, one additional well per GPU, two per GPU, whatever we think is appropriate, and then proceed on that type of path.

Q. Could it be applied to areas outside the unit?

A. If we felt that the geology was -- that the methodology for determining what is and isn't pay -- if we felt that the net effective -- If we had a net effective pay map that was accurate in our unit and was done by the same method or similar methodology throughout the Basin, yeah, I would assume that you could apply it wherever.

Q. Okay, your Exhibit Number 29 for the nine-section area, that is for the increased recovery that's going to result from drilling the new wells?

A. In addition to the 225E. It's going to be the nine wells we're proposing now plus the pilot well, the 225E, the other 80-acre well.

Q. Okay. And that was determined from your simulation?

A. That's correct, yes.

Q. And part of the data that you'll be gathering will help to verify whether this is correct or not?

A. Right, this will be our pre-work estimate, and then we'll see what our post-work estimate is.

Q. Are you going to be able to determine what the cumulative recovery of the new wells is going to be, what they're going to recover ultimately?

A. I think so. Yes, we should be able to. If we can see enough of the early time data and we can correctly tell how much gas there is in place, we should be able to pretty much forecast the interrelation between those wells and the existing wells accurately.

Q. And on Exhibit Number 30 for the 189F, this is what the simulation currently predicts how this well will behave --

A. Yes, that's correct.

Q. -- when it's ultimately drilled?

High initial producing rates, 1200 MCF a day, that decline rapidly to less than 200 MCF a day; is that --

A. Within two years, yes.

Q. Okay, that's what it predicts?

A. That's what it -- Right, that's correct.

Q. Did you guys -- Before you drilled the first six wells, did you do a similar type of simulation for those?

A. We did.

Q. And how did that come out?

A. And this is -- I'm going off what we brought you last time, that we came in with a higher gas-in-place estimate, and we came in with much lower initial production rates from the wells.

And I would attribute that to the -- Well, the modeling was done by people outside of San Juan, and they didn't take into account the fact that we're going to put big hydraulic fractures on these wells, and so they had wells that came on at 200 MCF a day and stayed very constant for a long time, as opposed to wells that came on...

So we're seeing rates much higher than we would have expected from the old simulation work, but it's -- the old simulation work wasn't entirely accurate in that sense.

Q. So have you used the new data that you've obtained from the drilling of the six wells to update your simulation?

A. Yes, when I went through and we estimated how these new wells were going to perform, we gave them 500-

foot frac half links and that accompanying skin, and based -- to get the kind of rates that we saw from our six pilot wells, yes.

Q. Okay. Your economics that you presented for these wells, that doesn't take into account a Mesaverde completion in the wellbore?

A. No, it does not.

Q. So that increases your economics?

A. That's correct, yes.

EXAMINER CATANACH: Okay, I have nothing further.

Mr. Chavez?

MR. CHAVEZ: Follow-up?

EXAMINER CATANACH: Sure.

FURTHER EXAMINATION

BY MR. CHAVEZ:

Q. In getting data on a 160-acre infill well, if the original well had not drained that portion of that 320 acres and you got original reservoir pressure, wouldn't that be significant and important in your model?

A. It is, and we did honor that in the model that -- The way we did the modeling to estimate the gas in place, when we did the pressure-matching in the model, one of the other -- in addition to having the constraint that the pressure at the pilot well we drilled had to match what we actually observed, I actually went through on the 160-acre wells, and I had the constraint that the pressure when we drilled those wells at that exact point could not be more -- less than 97 percent of the original gas -- original reservoir pressure.

So that doesn't -- that's not much -- all you're saying is, the pressure has -- All I was saying was, the pressure -- your drainage couldn't have gotten there yet, but that didn't really define where it was, if that's...

So that is an additional constraint. You could say, My model needs to ensure that when I drill these 160 -- that if I start in 1970 drilling 320s and in 1980 I go drill 160s, when I drill those wells, my model needs to say, hey, the pressure there is still virgin pressure. And that was a constraint I did put in.

Q. Okay, then, from your model can you estimate or predict the amount of area to be drained by well?

A. You can estimate the pressure at any distance from the well. So in that sense you could say that right next to the well it's basically surface pressure, and on out. So you could say that here there's 5 percent of the gas, 10 percent -- in that sense, yes, it's -- To drill an actual circle around the well, you'd have to say, What do I want to say? Do I want to say that -- How far away from the well am I at 90 percent of the reservoir pressure or 60 -- Whatever you chose to define as your drainage area, the model could tell you what that was, you know. But...

You could say where is the transient, yeah, where -- how far out from the well have I seen any depletion at all? Yes, the model will tell you that.

Q. Okay, so it might be helpful, then, to gather that data from the 160-acre infill wells, whether it was partially drained or not on that 160, for your model?

A. It might -- It would be helpful. Ideally, we'd like to see 500, 600, 400, 800 pounds of depletion. If we're looking at the difference between 50 pounds and 75 pounds or no depletion, you start there to get to errors within just how accurately you're measuring the pressure.

Ideally, we like to see data points where there's been some effect, but there's been -- The more effect by the offsets, the better. I mean, the better it is for -- that you're -- the more convinced you are that the offset actually caused there to be less pressure there than you would expect.

If it's -- You know, our original pressure estimate may be off by 50 pounds. So if you only assume 50 pounds of depletion, it's hard to true that necessarily to the drainage from a 320 well reaching a 160.

Q. Okay. On your Exhibit Number 31 you testified to increased density economics. Is this -- You prepared this?

A. Yes, I did.

Q. So you're estimating, then, and your testimony is that these wells are economic wells?

A. Yes, I am.

Q. How do you reconcile that with Exhibit Number 12, where Mr. Shannon said that one of his objectives was to test whether these wells were economically viable? Haven't you already met that objective then?

A. Well, we're predicting these wells. We're predicting the wells that we haven't drilled yet will be economically viable. So we're going to go test that concept by doing the wells, by drilling the wells, recalibrating the geologic model, putting the production data in and seeing if we really get this kind of...

So if you look at -- 31 is our projected economics, so that may be misleading. It's the economics of a simulation run if we drill the nine additional wells. So it's a forecasted economics for the nine additional wells.

And I think what Mr. Shannon is saying is, We'd like to go out and actually do these wells to see if that's correct.

Is that clear?

Q. If the production came in at -- using your model, at -- Let me ask you this way: How much less production would a well have to have from your model, or in actuality, to not be an economic well? Fifty percent? Or let me ask you, would an 80-acre well be economic at 50 percent of what you predict the production would be?

A. No, it would not. I cannot tell you what the exact number is. I'm guessing -- If we're talking 730 million cubic feet per additional well is what we're forecasting, I think the break-even is about half a BCF, in additional incremental reserves per well, is about the break-even for a Dakota single.

Q. Okay, so your economic viability will be -- based at that line, you haven't -- For example, in looking at the economic viability and using your calculated economics, you haven't put together a chart or something that might be helpful to understand, for us, what you're looking at here?

A. No, but I could. There is no chart in any of these exhibits showing the range of possibilities, showing the economics for a range of possibilities. We're going to go and say, We think this is our best guess of the possibility, and once we drill the wells we'll have an update and we can -- No, no, I do not have a chart that shows that.

Q. Given the quality --

A. I have a mental image of it.

Q. Given the quality of the actual production to your matching, how accurate would you say your estimate is?

You said you had a really good match on your model against the production, so would you say that Exhibit 31 is 98-percent correct, 99-percent correct?

A. Well, I think we need to drill the wells to say. But for the geologic model we have, and for what we've seen from our six pilot wells, which only one of them is in this area that we're predicting here, we're using those six wells to get an idea of what we think the completion efficiency would be for a new well, we're using the pressure data to predict what we think the gas in place would be.

And those two variables interreact, and when those two -- for the averages we've chosen, that this is the answer. We won't know -- I won't know how accurate this is until we actually drill the wells.

Q. But do you have some sense of probability that it has a certain degree of accuracy? Is that based on your corporate plan for ROI on wells? I'm wondering, your -- Everybody has a way to make these business decisions, so you must think that all these wells are important enough and profitable to drill.

A. We tend to do things based on our average estimate, and this is our average estimate, it's economic. We as a corporation would go forward based on this as our most likely hypothesis.

I'm not comfortable giving quantitative ranges of what could happen, but we definitely think that this may not happen. Hopefully -- that there's a 50-percent chance it will be better, and there's a 50-percent chance it will be less if we're really accurate, and this is our average estimate. That's -- I'm --

Q. Well, you're getting at the pilot wells that were drilled by that development?

A. The 219E -- or 219M, maybe, because they're uneconomic. And you know, again we've -- it's -- and when we're talking about uneconomic or economic, it's based on how accurate our forecast is of how they're going to do from now on. And we're not 100-percent sure that we have an accurate forecast of how they're going to do from now on.

You know, most of them have produced at fairly high rates for the point we -- period we tested them. But we need to get additional data to be able to be comfortable with saying how we think we're going to do from here on.

If it was me, I would say five out of six of them are really strong economic projects. But that's based on them being the only well we had in that area. You know, what we're talking about here is going in an adding nine additional wells in the area. They're going to steal some gas from that well and the other wells, and it's going to change the economic picture.

But we think -- I would say five out of six wells, by themselves, as stand-alone projects, if we didn't do any more drilling, would be really good economic projects.

MR. CHAVEZ: Thank you.

EXAMINER CATANACH: Anything further from this witness?

This witness may be excused.

MR. KELLAHIN: Mr. Examiner, the representative from the Bureau of Land Management would like to make a sworn statement.

EXAMINER CATANACH: Yes, sir. Were you sworn in?

MR. DEMBOWSKI: No, sir.

EXAMINER CATANACH: Okay, can we do that, please?

(Thereupon, the witness was sworn.)

RICHARD K. DEMBOWSKI,

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

MR. DEMBOWSKI: For the record, my name is Richard Dembowski. I'm the Petroleum Management Team Leader in the Farmington Field Office of the Bureau of Land Management. I've been working closely with Conoco, as have other members of my team throughout the generation period of this project.

The BLM, as you -- well, we're all aware -- is charged with ensuring the conservative production of mineral resources and maximizing return to the American people. So we are the mineral owners' representatives, essentially the mineral owners.

Regarding the proposed expansion, my teams conducted a detailed review of the engineering and geologic datum, and BLM takes the position that the pilot be approved as proposed.

The affected wells are located in a unitized area containing predominantly federal minerals. There are no correlative-rights issues apparent in the proposal. The wells are located not only within the unitized area but within established participating areas, of which Conoco is the operator, and that applies to both the Dakota and Mesaverde.

The fracture identification procedures that you heard earlier in testimony support the ongoing analysis efforts being performed by New Mexico Tech in reference to the San Juan Basin.

In addition to working with industry, under both industry and Department of Energy funding, New Mexico Tech is also working with the Farmington field office, specifically with my team, under a cooperative funding agreement. This cooperative agreement has been activated so that Tech, in conjunction with industry, NMOGA, NMOCD and the Bureau of Land Management, may develop a reasonable foreseeable development scenario for the San Juan Basin. This is in conjunction with our resource management plan we write that we have ongoing right now in the Farmington area. The information that Conoco proposes to gather during this pilot will be critical and will further support this collaborative effort with New Mexico Tech.

The pilot extension makes provisions for maximum wellbore utilization, given the planning for multiple-zone completions and downhole commingling.

The Bureau of Land Management supports this effort completely. This proposal resolves all surface-impact issues with the BLM through the reduction in the number of wells that will be required to drain those multiple reservoirs. The pilot expansion will also serve to prove both new reserves and accelerate recovery on existing reserves.

With approximately -- well, you've heard from 7 to 10 BCF in cumulative additional recovery, including accelerated, you're looking at something over $3 million in net royalty revenue that will accrue to both the State of New Mexico and the federal government. This does not consider any severance taxes or any other taxes that may be imposed on a local level.

In summary, the BLM supports this pilot expansion program in the strongest possible terms.

That's all I have, sir.

EXAMINER CATANACH: Thank you.

Mr. Kellahin, do you have anything further in this case?

MR. KELLAHIN: No, sir, that concludes our presentation, Mr. Examiner.

EXAMINER CATANACH: There being nothing further in this case, Case 12,556 will be taken under advisement.

And this hearing is adjourned.

(Thereupon, these proceedings were concluded at 3:19 p.m.)

* * *

12556
December 7 - 2000

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 December 13th, 2000.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002