STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:	CASE NO. 12,745
APPLICATION OF BURLINGTON RESOURCES OIL AND GAS COMPANY AND CONOCO, INC., TO AMEND THE SPECIAL RULES AND REGULATIONS FOR THE BASIN-DAKOTA GAS POOL TO INCREASE WELL DENSITY AND AMEND WELL LOCATION REQUIREMENTS, SAN JUAN, McKINLEY, SANDOVAL AND RIO ARRIBA COUNTIES, NEW MEXICO	ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

October 18th, 2001

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MICHAEL E. STOGNER, Hearing Examiner, on Thursday, October 18th, 2001, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

October 18th, 2001
Examiner Hearing
CASE NO. 12,745

(Continued...)

APPLICANT'S WITNESSES (Continued):

* * *

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* * *

Additional submission by Bureau of Land Management:

	Identified
Statement dated 10-16-01	8

* * *

A P P E A R A N C E S

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By: WILLIAM F. CARR

ALSO PRESENT:

FRANK T. CHAVEZ
District Supervisor
Aztec office, District 3, NMOCD

JAY SPIELMAN
Geologist, BLM
Santa Fe, New Mexico

* * *

WHEREUPON, the following proceedings were had at 1:35 p.m.:

EXAMINER STOGNER: At this time I'll call Case Number 12,745, which is the Application of Burlington Resources Oil and Gas Company and Conoco, Inc., to amend the special rules and regulations for the Basin-Dakota Gas Pool to increase well density and amend well-location requirements governing San Juan, McKinley, Sandoval and Rio Arriba Counties.

Does this cover McKinley County, Mr. Chavez?

MR. CHAVEZ: No, sir, the pool does not exist in that county.

EXAMINER STOGNER: Okay. Well, we advertised in that county and they do border that particular county line, so this is appropriate.

At this time I'll call for appearances.

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin. I'm appearing on behalf of Burlington Resources Oil and Gas Company; Conoco, Inc.; Pure Resources, L.P.; and Phillips Petroleum Company.

EXAMINER STOGNER: How many witnesses do you have?

MR. KELLAHIN: I have five witnesses.

EXAMINER STOGNER: Any other appearances?

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe office of Holland and Hart, L.L.P. We'd like to enter our appearance on behalf of BP America, Inc., and Williams Production Company, LLC.

EXAMINER STOGNER: I'm sorry, who was the first one?

MR. CARR: BP America, Inc.

EXAMINER STOGNER: Any other appearances?

Mr. Brooks, do you if the Division will have a witness today?

MR. BROOKS: That depends on the presentation. We intend to question some of their witnesses, and depending on the testimony I think Mr. Chavez may want to testify.

EXAMINER STOGNER: Okay, now I know there's some other government -- Okay, as far as the company representatives, is there any other company representatives here?

Okay, I believe there are some government entities from the federal and tribal level. I'd like to recognize those at this time, if you'll stand up, introduce yourself and your affiliation.

MR. SPIELMAN: Good afternoon, Mr. Examiner. My name is Jay Spielman, I'm a geologist with the Bureau of Land Management in Santa Fe. Our Farmington field office has prepared a letter supporting Burlington's and Conoco's Application, and I would eventually like to introduce that into the record.

EXAMINER STOGNER: And you have some copies of that letter, I assume?

MR. SPIELMAN: Yes.

EXAMINER STOGNER: Okay. Any other representation, any other government entity?

Tribal entity?

There being none...

Mr. Kellahin?

MR. KELLAHIN: Yes, sir. I have that letter.

EXAMINER STOGNER: Do you have that letter?

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: Mr. Carr? I'm going to leave them here, then, if anybody else needs additional.

Thank you, Mr. Spielman, and if you'd like later on to ask questions or make an additional statement in regards to this or anything else you'll be allowed to at that time.

At this time I'll ask all the witnesses to stand at this time, and if there are any subsequent witnesses that aren't standing now, please remind me should you be asked, forced or whatever to come and testify.

(Thereupon, the witnesses were sworn.)

EXAMINER STOGNER: Is it necessary for any opening remarks at this time, Mr. Kellahin, Mr. Carr?

MR. KELLAHIN: Briefly, Mr. Stogner.

EXAMINER STOGNER: Please.

MR. KELLAHIN: Our presentation today, Mr. Stogner, deals with the Basin-Dakota Pool. You may recall that in February of 1999 you were the Hearing Examiner, and you issued the order in the Mesaverde, the Blanco-Mesaverde Pool, that made substantial changes in the well-location requirements for the Mesaverde and the well density.

In addition, I'm sure you're aware that you entered an order in June of the year 2000 in which we began to make certain well-location changes in the Basin-Dakota Pool.

Thereafter, Examiner Catanach heard three separate cases, one involving Conoco in a Dakota pilot project in the 28-and-7 Unit, and then Burlington for a pilot project in the 27-and-5 Unit, followed by Burlington's presentation in what we call the Culpepper-Martin area.

We are now back before you based upon the results of those pilot programs, and after discussions with the operators and other interested parties in the San Juan Basin we are proposing this to you, sir, that there is unanimous agreement to make a poolwide change, there is no support for subdividing the pool and using different rules within the Basin-Dakota. So our proposal would cover any well in the Basin-Dakota Pool.

The well density request, based upon our technical results, demonstrates that it's now appropriate to increase well density in the Dakota so that you would have, instead of the current two wells per 320, a maximum of four wells per 320, with no more than two wells located in any 160. That is consistent with what Mesaverde does now.

In addition, we're asking you to increase the standard well-location windows in the Basin-Dakota. Currently, based upon the rule change you made in June of the year 2000, there is a 660 setback within each 160-acre portion of the 320, plus we have a 10-foot internal setback.

You may remember that the Mesaverde deletes the internal 660 setback between the two 160s and simply uses an outer boundary 660 setback. Our plan is to make those rules the same.

In addition, we are going to make a presentation to you that deals with the federal exploratory units. As you and I and others have discussed for a number of years, there's a need to make special rules concerning well locations in exploratory units. And as the discussions have evolved, we're in a position this afternoon to make a recommendation to you that the federal units be allowed to locate their wells 10 feet off any boundary, with the exception of the outer boundary of the unit, which continues to maintain a 660 setback.

In addition, we're going to propose restrictions that are more restrictive than the current Mesaverde. Right now, as you know, for federal units in the Mesaverde the only restriction is to be 660 from the outer boundary of the unit, and we are not asking you today to make the Dakota rules identical to Mesaverde.

To the contrary, we're seeking to address the concerns about correlative rights within a federal unit, and our proposal is, in addition to the 660 outer boundary, if there is a tract internal to the boundary, a 320 spacing unit, that contains no acreage committed to the unit, it is fully uncommitted, then there would be 660 buffer on the unit side of that GPU.

In addition, if there is a GPU within the federal unit that contains only partially committed tracts to the unit -- in other words, there is a royalty owner that does not have his royalty interest committed on anything other than a tract basis, there would be an additional setback as to that spacing unit, the setback would be internal to the unit, and it would be 660.

In addition, there has been discussion with the District Office about whether or not there ought to be additional 660 setbacks when a well is drilled in a tract that's not yet added to the participating area. We're going to have that discussion with you and describe for you our position as to why that notice is not necessary.

In addition, there is a hybrid of that situation where there may be a well drilled on the uncommitted tract where the PA has not been expanded and that well is deemed uncommercial.

There may be a situation where correlative rights are at issue. Our position is, there's contractual solutions in the unit agreement, the unit operating agreement, balancing the equities, and we may have a disagreement with the District Office about the notice requirement.

So our plan is to ask you to approve what is in essence the same type of rules for the Mesaverde, with the exception of the federal unit setbacks, we're asking you to propose for the Dakota Pool the setbacks as I've identified.

If that's acceptable to the Division, then I've been instructed by Burlington to file a case for the Blanco-Mesaverde Pool to make the federal well-location restrictions the same for that pool as you decide they should be for the Basin-Dakota, and I've been instructed to do that.

I have five witnesses to present to you.

Mr. Jack Kean is a petroleum engineer with Burlington. He is going to give you what I will call an executive overview. He will show you why we're here today, he will give you a checklist of what he wants you to provide in terms of a rule change and the reasons why he thinks they're justified.

We're then going to give you a comprehensive geologic presentation by Burlington's Geologist, Glen Christiansen, and we're going to show you the key portions of those geologic displays that give you the basis for what we think is a necessary change in well density.

Then we're going into two reservoir-simulation presentations. You're going to see the first one from Conoco. Mr. Jim Kolesar is a reservoir engineer, he does reservoir simulation for Conoco. He's going to give you the results from their 28-and-7 pilot project and the results of his simulation.

Then Mr. Craig McCracken, Burlington's reservoir simulator, is going to do the same for the Burlington pilot projects, which were the 27-and-5 Unit and the Culpepper-Martin.

Then we're finally going to conclude with Mr.

Matt Gray. Mr. Gray is a petroleum landman. He's spent considerable time and effort studying the well-location issue within the federal exploratory units, and he will be our main witness as to that discussion.

And at the conclusion of that presentation, then, we would ask you to approve Burlington's request.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Carr?

MR. CARR: I have no opening statement.

EXAMINER STOGNER: You may proceed, Mr. Kellahin.

MR. KELLAHIN: Call Mr. Jack Kean.

For the information of the participants in the audience, I have distributed hard copies of the exhibit book to those attorneys and companies that are participating in the case. If there is someone that does not yet have that book, if they will give me their business card at the conclusion of the hearing, we will make available copies of the exhibits that are being presented.

The exhibits you're looking at in the book, Mr. Stogner, will be the same that you're going to see on the PowerPoint presentation on the screen to your right, but the hard copies are available so that you'll have that as a source.

With that introduction, we'd like to begin with Mr. Kean.

JACK KEAN,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. All right, sir, would you please state your name and occupation?

A. My name is Jack Kean, I'm a petroleum engineer with Burlington Resources.

Q. And where do you reside, sir?

A. I reside in Farmington, New Mexico.

Q. You spell your last name K-e-a-n?

A. That is correct.

Q. I got that part right, right? Have you testified on prior occasions before the Division?

A. Yes, sir, I have.

Q. What is your role or responsibility concerning Burlington's study of the Dakota Pool and the proposed changes to the Basin-Dakota Pool rules?

A. My role has been to, over about the past year, study the technical data and evaluate whether or not the density should be changed in the pool.

Q. Do you now believe you and the other members of the team have sufficient data upon which to make recommendations and conclusions?

A. We have sufficient data at this time.

Q. And you have now reached conclusions and have recommendations for the Division?

A. Yes.

MR. KELLAHIN: We tender Mr. Kean as an expert petroleum engineer.

EXAMINER STOGNER: Mr. Kean is so qualified.

MR. KELLAHIN: Mr. Kean's exhibits in the exhibit book are going to be found behind Exhibit Tab 4 through Exhibit Tab 9, and we're going to start with Exhibit Tab Number 4, if you'll put that up on the screen for us.

EXAMINER STOGNER: Before we start, can everybody see that, especially on this side of the room? Are there going to be any dark-colored exhibits, Mr. Kellahin?

MR. KELLAHIN: There are some geologic displays. I think they will project with the lights on. We'll attempt to leave the lights on. If it becomes too difficult to read, then you can decide how to handle that.

EXAMINER STOGNER: Okay, I like this so far.

MR. KELLAHIN: All right.

Q. (By Mr. Kellahin) Mr. Kean, before we talk about the summary page which is up on the display, give me some more information about the role you've played on the Burlington group that studied the Basin-Dakota.

A. The role I played was to initially help identify areas where Burlington can conduct pilots, which we came before this body about a year ago.

After the pilots were selected, I was involved in evaluating the data that we learned from those pilots. And in addition, I also participated in simulation work.

Q. Are the opinions that you're about to express your own personal engineering opinions?

A. Yes, they are.

Q. Do they also represent the collective technical opinions of Burlington and the participants on your work group that studied the pool.

A. Yes, they do.

Q. All right, let's start with the first recommendation. Why are you here before Examiner Stogner and what are you seeking to do?

A. Burlington and Conoco would like to increase the density in the Basin-Dakota Gas Pool from a maximum of two wells per GPU to a maximum of four wells per GPU.

In addition, we would also like to amend the well-location requirements.

Q. Let me ask you about the first conclusion you've put upon the display. It says that "Current density is not sufficient for adequate drainage". That's one of your conclusions, right?

A. Yes.

Q. Let's go to the tab behind the summary sheet -- In fact, maybe we ought to just take the summary sheet out of the book. Let's keep that set aside so we can keep track of your conclusions. And if we'll look at the next display behind the summary page, what are we looking at, Mr. Kean?

A. This is a pie chart that represents the estimated ultimate recovery of all existing Dakota wells in the Basin-Dakota Pool; that is represented in red. In blue is the remaining resource that is not recoverable under existing densities.

Q. Are these Burlington's wells or all Dakota wells?

A. These are all Dakota wells in the Basin.

Q. And approximately how many wells are you dealing with?

A. There is approximately 5100 that we have in our database that we have evaluated the EUR.

Q. All right. Describe for me the information I should understand is important to you when I look at this display.

A. This is very important. Approximately 56 percent is the recovery factor for the existing wells. Approximately 44 percent will be left behind under existing density. That 44 percent represents a little over 5 TCF.

If you will notice in the lower right-hand corner

I've printed off the EUR -- again, that's from all existing wells based on rate-time forecasts -- and the gas in place, which is the gas in place within 160 acres of the existing wells.

Q. If the pool is further developed under the current rules, will you obtain a portion of the resource shown in blue?

A. No, we will not.

Q. So the only way to capture that additional resource is to increase the well density?

A. That is the only way.

Q. All right, sir. Let's turn to the next item. It says the "Pilot results are better than expected". The information that supports that conclusion is behind Exhibit Tab Number 5?

A. Yes, it is.

Q. What were the results and what had you expected?

A. Okay, the results were, the rate of the pilot wells that we drilled and the pressures that we obtained from those pilot wells were higher than we expected.

Q. Let's look at the first display and look at the production results.

A. Yes.

Q. Show us how to read the display. How do we read it?

A. Okay, this is from the Culpepper pilot area. On the Y axis is daily rate in MCF a day. On the X axis is delta time, and that is in months. The blue squares that you see are the average production rate from the three pilot wells that we drilled in the Culpepper area. The red line is what we expected to see before we drilled those wells. The red line is based on simulation, and that is what we presented about a year ago when we asked to do the pilots.

Q. So if the actual production rate of the pilot wells is better than expected, how do you apply that to a decision about well density?

A. The reason for the higher production rate is pressure, and the pressure was higher than we expected.

Q. And if the pressure is higher than expected and the producing rate is higher than expected, what does that tell you, if anything, about the current well density?

A. It tells us that the current well density is insufficient to drain the reservoir adequately.

Q. And why is that so?

A. Because the pressure is so much higher than we expected. Very little depletion has occurred, and that is manifested in these higher production rates.

Q. Let's turn to the next display and look at that information for the San 27-and-5 Unit.

A. This is the same type of data, San Juan 27-5. Once again, it illustrates that the production rate of the pilot wells was higher than we expected.

Q. Okay, let's turn to the next display and identify that.

A. Okay. Once again, this is from Conoco's San 28-7 Unit pilot. And again, the actual production from the pilot wells exceeded the pre-pilot estimates.

Q. All right, we've looked at the three pilot areas in terms of their producing rate. Do you have pressure data on the pilots?

A. Yes, we do.

Q. Let's turn to the next display and look at that.

A. This may be one of the most important displays that I show you today. What you see is pressure on the Y axis. The red bar represents the original pressure in each of the pilot areas. The blue bar is the actual average of the pressures that we measured from our pilot wells in each area. The light blue is the estimate prior to conducting the pilots.

And so as you can see, for example, in 27-5, the initial pressure was approximately 3100 pounds. Currently based on our pilot data, that pressure is approximately 2650 p.s.i.

Q. Again, what does this tell us in relation to well density?

A. It tells us first of all that we had to increase our gas-in-place estimates because they were too small. The pressures were higher than we originally thought. And since so little depletion has occurred in, say, the 20 years since 160-acre wells were approved, it tells us that the current density is insufficient to drain the reservoir.

Q. Let me have you identify something in the exhibit book at this time. If we look at Exhibit Tab 20 --

A. Yes.

Q. -- what is contained in the book behind Exhibit Tab 20?

A. Exhibit Tab 20 contains reference material. It is organized first by data acquired by Conoco in 28-7, then data acquired by Burlington in the Culpepper area, and then data acquired by Burlington in the 27-5 area. This contains well logs, simulation history matches, pressure data and production data from each of the pilot wells.

Q. It's not my intent, Mr. Kean, to go through Exhibit 20 with you or with any other witness. I wanted to have Mr. Stogner aware, though, that the supporting technical data for the conclusionary exhibits that we're discussing now is contained behind Exhibit Tab 20; is that a true statement?

A. That is a true statement.

Q. Has Burlington satisfied itself that there is adequate data to reach conclusions about the pilot project areas in terms of well density?

A. The pressure data is very conclusive, and we do not need any additional data.

Q. Do you see any reason to have further pilot projects in the Dakota before the Division makes a decision about increasing well density or changing well-location requirements?

A. There's nothing additional that we could learn regarding density by doing additional pilots.

Q. In your opinion, are the three pilot areas still representative of the range of reservoir characteristics that are normally encountered within that portion of the Dakota that's been developed?

A. Yes, the are. We took care to select pilot areas that have different producing and geological characteristics.

Q. Let's go to the next conclusion you had on the summary sheet, which says the "Pilot results are transferable to the entire pool". What do you mean by that conclusion?

A. There needs to be a way to take what we learned from our pilots and to transfer that to the rest of the pool in a way that can qualitatively help us understand what we'd expect in the Dakota reservoir in areas outside of the pilots.

Q. Can you give me a quick summary on how Burlington and Conoco reached the conclusion that we could transfer the pilot results to a poolwide decision on well density? What did you do?

A. We developed or found a relationship among the pilots, based on the pressure data and the production data that we could apply to the rest of the pool, based on parameters that we know in other parts of the Basin, in other parts of the pool.

Q. Let's turn to Exhibit Tab Number 6, and begin to demonstrate to Mr. Stogner how you have made that transition from a pilot conclusion to a poolwide conclusion.

A. Okay. The first is -- that I show here is a relationship between the 160-acre infill-and-parent EUR ratio and new or incremental reserves as established by the pilot, and it can be applied to the pool.

On the Y axis, I've printed out new reserves. Those are incremental reserves determined by simulation that will not be recovered under current density. These are reserves that a third and fourth well per GPU in the three pilot areas would recover.

On the X axis is the 160-acre infill-to-parent

EUR ratio. That is known throughout the Basin where 160-acre wells have been drilled. That is a parameter known outside of the pilot areas.

There are four points that define this relationship. Two of them were determined by Burlington in reservoir simulation, the Culpepper and 27-5 areas. The third was determined independently by Conoco in their 28-7 area.

What this means is, I can take that ratio -- say it's .5 of a B, or .5 -- and following that up to the red line I can determine that I might expect .4 of a B incremental or new recovery in that particular area. This is a qualitative look that gives us a feel for what we might expect in areas outside of the pool.

Q. All right, let me see how to make the display work. On the X axis you've developed a ratio between the parent well on 320 and the 160-acre offset infill well?

A. Yes.

Q. And that ratio, then, is defined along the X axis?

A. That is correct.

Q. And then on the Y axis there is a relationship with new reserves that would be generated if you drilled -- four new wells? How many wells are we dealing with?

A. A third and a fourth well.

Q. All right. So are the numbers derived on the Y axis applicable to the third well and then the fourth well?

A. They're applicable to the average of the third and fourth wells.

Q. All right. What I'm asking, though, is, on the 0.6 BCF -- Do you see that? Is that two wells or one well?

A. One well.

Q. All right, so if I add two more wells to my GPU, it's going to be 1.2?

A. That's correct.

Q. Tell me how I make this work. Now, I'm following the red line, and I know the ratio to my parent and infill on EUR, I can find that point on the red line, and then do I read horizontally across to get my reserve value?

A. Yes, from your ratio you go vertically till you intersect the red line, and then you move horizontally to the left.

Q. By looking at this display, can I assume that the 28 and 7 has better potential for additional wells than the Culpepper-Martin area?

A. That is correct.

Q. But within this range your recommendation is, all of these areas justify the additional wells, or at least the opportunity for the additional wells?

A. Yes, they do justify the opportunity.

Q. All right, let's turn to the next display and have you identify and describe this display.

A. Okay. Again, there's a relationship established by the pilot areas, this time between the 160-acre initial infill pressure and again, as I described before, on the Y axis, new or incremental reserves. The Y axis is the same as the previous graph.

The X axis, however, is the surface, the average surface pressure that was measured when the 160-acre infill wells were first drilled. The three points that you see were again defined by reservoir simulation, and they are the same as on the previous graph.

Q. All right, if I'm another operator and have this graphed, and I know the infill initial pressure on my 160, can I use that to decide whether I ought to increase my well density in my GPU or not?

A. This graph will give you a qualitative feel for whether you should look at it.

For example, if one is in an area where the initial infill pressure was 1500 pounds, by looking at this chart one might conclude that there would be .4 of a B incremental reserves. And at that point, perhaps with additional engineering work, that operator could decide whether or not to increase the density.

Q. All right, he could apply his own economic basis to the fact that this pressure will allow him the opportunity to recover .4 BCF per well, and then he'll make his choice about whether to take the opportunity to drill that well?

A. That is correct. And this is just the incremental component; it does not include the acceleration component.

Q. All right, let's talk now about the next conclusion. It says "Up to four wells per GPU are appropriate for the pool". And I assume you mean the entire pool.

A. That is correct.

Q. Let's look behind Exhibit Tab Number 7 and talk about the supporting documentation for that conclusion.

A. Okay. The first Exhibit behind 7 is a foldout map.

Q. Hang on just one minute. All right, sir, if you'll turn to Tab 7, let's look at the foldout. What are we looking at?

A. This is a map that in blue gives the outline of the Basin-Dakota Pool. You'll also notice a light purple line, which is the Pictured Cliffs outcrop. The three pilot areas that Burlington and Conoco conducted are outlined in red, and in purple are the existing Dakota wells.

Q. It's simply to give a visual illustration to the Examiner of where wells have actually been drilled within this very large pool?

A. Yes.

Q. What accounts for the fact that there are not wells west of this fairway or east of this fairway?

A. There certainly are geological reasons that that is the case. For instance, there is updip water in the Dakota, and that generally prevents drilling to the west and to the east.

Q. All right, let's go behind the foldout, and let's look at the next display. Identify and describe that for us.

A. All right. This display indicates that four wells per GPU are appropriate in the Culpepper area. On the Y axis is the EUR. This is EUR from third and fourth wells per GPU. The dark blue is the acceleration component. The light blue above is the incremental recovery.

For example, fourth well per GPU acceleration is approximately 1.5 BCF, the incremental recovery is approximately .2 of a B, or about 57 percent.

I conclude from this that four wells per GPU is appropriate because the fourth well adds incremental reserves. You can see by this table or this graph that the third well adds incremental reserves. The fourth well does too. If the fourth well did not add incremental reserves, of course, that bar would be all dark blue.

Q. Can you give us a percentage on the fourth well as to what is incremental and what is rate acceleration?

A. 57 percent is incremental.

Q. All right, sir, let's look at the display for the San Juan 27-and-5 unit, if you'll turn the page.

A. This is the same type of display. Once again, EUR is on the Y axis. You'll immediately note that a well, third and fourth well in the 27-5 unit, will result in a higher EUR than in the Culpepper area. For example, the fourth well will add about .8 of a B incremental reserves that will not be recovered under existing density. That's about 67 percent of that profile will be incremental.

Q. Do you have an opinion as to whether increasing the well density to four wells per GPU or eight wells per section is appropriate for the whole pool?

A. This is definitely appropriate for the whole pool, because we will clearly add incremental reserves as demonstrated in the pilot areas.

Q. Is there any support, in your opinion, for the presumption that we ought to continue under the current rules until all the 320s have been drilled with an initial well and an infill well? The question is, is it premature to change the rules?

A. It is not premature to change the rules. As we noted earlier on, there are places that right now are legal to drill Dakota wells, but they have not been drilled because economics and geology constrain the operators.

Q. Well, let's go back to Exhibit Tab 7 and let's look at the foldout map, and we can see some of that, can't we?

A. Yes, Exhibit Tab 7, you will notice over 5000 Dakota wells have been drilled. But there are also large areas that Dakota wells have not been drilled. Economics and geology have constrained operators from overdrilling in the past.

Right now it's not premature to increase the density, because Mesaverde 80-acre development is ongoing. That 80-acre development provides us with an opportunity to drill Dakota wells in areas that may be uneconomic as stand-alones.

Q. Let's talk about the link or the connection between the opportunity to increase incremental reserves from the Dakota with what is happening in the Mesaverde. In other words, in the Mesaverde you're drilling a well. How are you proposing to access and utilize that wellbore for the Dakota?

A. Through commingles where it is economic.

Q. Do you see any future probability for stand-alone Dakota wells to be drilled?

A. There is minimal future opportunity to drill Dakota stand-alones, for the simple that many of the best locations have already been drilled.

Q. So while there will still be some stand-alone Dakota wells, the opportunity for future recovery out of the Dakota is by necessity linked to a Mesaverde well?

A. Yes, it is.

Q. Let's turn to Exhibit Tab Number 8 and talk about that relationship.

A. All right. This is a bar graph. On the Y axis is well count. This is Burlington Resources data.

Q. So this is Burlington's well count, not --

A. Yes.

Q. -- anybody else's?

A. This is Burlington's own.

Q. All right. Tell me how to read this.

A. Okay. The light blue represents Dakota-only wells. The dark blue represents Mesaverde-only wells. And the red represents Mesaverde-Dakota wells. Those include commingles and dual completions.

Q. As we look from left to right, then, it's apparent that development of both the Dakota and the Mesaverde are linked by wells that are Mesaverde and Dakota downhole commingling?

A. Yes, there is an increasing trend of Mesaverde and Dakota wells that have been commingled.

Q. Let's turn to the next display and describe the economic environment that causes that to happen.

A. This is a table that demonstrates the economic incentive to drill commingles. The first column represents a Mesaverde stand-alone. You'll notice the capital, about $530,000, in this case .8 of a B EUR. You will notice that this is about break-even. PI is zero.

In the same location, if I were to drill a Dakota stand-alone, it's more expensive, less reserves. This is a project or a well Burlington would not drill as a stand-alone. However, if you look --

Q. Well, look at the negative number.

A. Yes.

Q. That's the point of the PI and the NPV?

A. Yes.

Q. If those are negative, you're not going to do it?

A. That is correct.

Q. Then how do you produce that resource? How are you going to do it?

A. We're going to do it through commingles. In the third column you'll see the cost of a commingle in this case is about $770,000. However, we're able to get both the Mesaverde and the Dakota reserves. That gives us a PI of .2, positive number, and an NPV of 130,000. That is a positive number also. In this case, the commingle is the only way that we can get to the Dakota and develop it economically.

Q. Let's talk about some general reservoir characteristics of the Dakota. Is the permeability in the Dakota high enough to give you any concern about relaxing the well locations in the Dakota to match those that are currently available in the Mesaverde? Are you putting your wells too close together, is the question.

A. No, we are not. The permeability is very low in the Dakota, and that low permeability does not cause any problems with the spacing.

Q. Can you give me a generalized example to illustrate the substantial low permeability? In other words, if I'm the offsetting operator and you're drilling a well in close proximity to my spacing unit, with this low probability how long a period of time would you estimate would pass before I should be concerned about being drained?

A. A very long time. Reservoir simulations, some of the exhibits that you will see later show that there is not really measurable acceleration or drainage until beyond 10 years. In addition, as evidence of this low permeability, extended buildups have been done in the past which demonstrate an extraordinarily long time, in many -- in some cases up to two years for the reservoir pressure to build. That is indicative of very low permeability.

Q. Let's go to the conclusionary slides that support your opinion that "Additional wells will result in additional recovery", and if you'll do so by turning to Tab 9, let's look at the supporting illustrations.

A. Tab 9 is a bar graph. On the Y axis is a percentage of gas in place, or recovery factor. For each pilot area in red represents the recovery under the current density. You will notice that it ranges from about 36 percent in San Juan 28-7 to about 65 percent in the Culpepper area.

The blue represents the incremental gas that can be recovered through increased density in each of these areas. For example, in San Juan 27-5 under current density we will only recover about 48 percent of the resource. However, if we increase that density by adding a third and a fourth well, we can increase that recovery to nearly 70 percent.

Q. Finally, let's turn to the topic of what other operators have expressed to Burlington and Conoco about the proposed rule change. What support do you have for making these changes, if you have something that summarizes --

A. Yes.

Q. -- those meetings and the results of their comments.

A. Burlington and Conoco have, along with the Aztec NMOCD, initiated a number of meetings. In particular, on July the 10th Burlington and Conoco hosted a working interest owners' or an operators' meeting in which we communicated the results, the initial results of our pilots and also sought comments from the operators.

The operators -- There was a consensus to increase density, to make location requirements to be very similar and complementary to the Mesaverde, and that there was no need to subdivide the Basin-Dakota Pool.

Q. We have also received letters of support from the BLM and also nine other companies or entities. Those are listed -- or those letters are behind Exhibit 19.

MR. KELLAHIN: Mr. Examiner, that concludes my examination of Mr. Kean. We move the introduction of the exhibits he's identified as Exhibit 4 through 9 plus Exhibit 20.

EXAMINER STOGNER: At this time I will admit Exhibits 4 through 9. Do we want to -- are we concluded with 20, or will you be referring back to that?

MR. KELLAHIN: No, sir, we will not specifically refer to 20. It's the supporting data for all the technical witnesses. But their presentation will be behind other tabs than 20.

EXAMINER STOGNER: Okay. So Exhibit Number 20 only relates to 4 through 9?

MR. KELLAHIN: No, sir, it relates to all the documentation in the book, it supports all the other tabs. And if you want to wait, we'll introduce that later.

EXAMINER STOGNER: Why don't we introduce that one later, and remind me if you would, please.

MR. KELLAHIN: All right, sir.

EXAMINER STOGNER: Mr. Carr, any --

MR. CARR: No questions, Mr. Stogner.

EXAMINATION

BY EXAMINER STOGNER:

Q. Okay, Exhibit Number 4 -- this is your pie chart -- you're saying that 7.2 TCF is the estimated unrecoverable? Is that what that is?

A. It's the estimated ultimate recovery.

Q. Ultimate recovery, okay. Now, what is your estimated unrecoverable reserves from the Dakota no matter what the 80-acre infill provisions today? How much is going to be left in the ground?

A. Out of the total pool, or just in areas where we've drilled?

Q. Total pool.

A. The total pool, there is over about 25 TCF.

Q. 25 TCF, and that's your -- Okay, 25 TCF is represented as what?

A. That is the total pool gas in place.

Q. Good, that's what I was trying to get at.

Okay, I want to refer now to the Exhibit Number 5. These are your estimated or your pre-pilot projections. Now, it's odd to me that you would have pre-pilot projections that missed the mark so much, in some instances, especially your 27-5 and then Conoco's 28-7. Did I miss something there, or did you feel you were off the mark, or do you want to explain that a little bit more?

A. The main reason is, in our prepilot simulation the reservoir pressure that we have dialed into the models was simply too low. When we went out there and actually drilled the wells, we found a higher reservoir pressure than we anticipated. That was one of the main reasons that we missed these production estimates.

Q. And there were a number of wells -- Let's take this 27-5, for example. What's the rough estimated number of wells or proration units that you -- Okay, let me rephrase that. How many infill wells did you end up drilling in this pilot project?

A. We drilled eight.

Q. Eight. Of all the eight that you drilled, and these were in quarter sections that had existing wells; is that correct? Or that they have -- or any of them had old wells that had been P-and-A'd --

MR. KELLAHIN: Mr. Examiner --

EXAMINER STOGNER: Yes.

MR. KELLAHIN: -- if you'll turn behind Exhibit Tab 2 --

EXAMINER STOGNER: 2.

MR. KELLAHIN: -- and look at the third display, it will show you the 27-and-5 unit, and it identifies in red the pilot wells. Do you see them in the red squares?

EXAMINER STOGNER: Oh, okay. Okay, so that's my --

MR. KELLAHIN: And there are similar displays for the other two pilot areas. So that will help you visualize where the pilot wells were placed.

EXAMINER STOGNER: Okay, thank you for pointing that out.

Q. (By Examiner Stogner) My question, of all of these eight wells in particular -- and we're going back to the 27-5 unit -- all of these eight wells you experienced a higher-than-expected pressure, or did you see some that was on the line and, say, some that was just way above, or did they kind of hold to this spread that you have indicated?

A. The results from our pilot wells in 27-5 were fairly consistent, both in terms of initial rates and also in terms of the layer pressures that we measure. We were able to successfully measure the layer pressure on two wells, and we found them to be relatively consistent.

Q. Did you choose these infill wells on the quarter section that had the original well, or the initial infill well in instances, or did you experiment throughout the infill project?

A. We actually placed the wells -- our intent was to add a third well per GPU, to place that well within, I believe, topographically and then also within a certain distance of roads. And we did not intentionally look to place them offsetting a parent well or an infill well.

Q. Okay, on your tab Number 5, the red bar, original pressure, now this was original reservoir pressure or original pressure for the well within that 160?

A. Original average reservoir pressure.

Q. For just the pilot project area?

A. Before drilling commenced, so this goes back to the original 320 wells.

Q. Okay. Tab Number 6, I know there area a few instances where operators have replaced existing wells, Dakota wells. Did you by chance check this bar with any of those instances, or do you know if Burlington has any of those instances where you have had either an original well or an infill well, and that well was P-and-A'd for some reason and a replacement well was put in that quarter section? Did you double-check in those instances this bar line? And this is outside of the infill areas, but I just wondered if you might have done any of that double-checking, perhaps.

A. I'm afraid I don't understand how you mean double check.

Q. Okay, you've got this tabulation here, and you said that you could utilize this, or this would be a good prediction anywhere within the pool, and I was just wondering if, because you had those instances and other operators -- I know Burlington has those instances --

A. Yes.

Q. -- have approved some unorthodox locations for replacement wells. Did you take that opportunity to check in those instances, either with the pressure or the new reserves or your EUR ratio in those instances along with this bar to see if it was accurate?

A. That's a good question. I did not check specifically the redrills to see if it made sense.

The check that I did do, however, was -- I knew the parent EUR ratio, so I took a couple areas and determined what that incremental reserve would be. Then I flipped the page. I knew what the initial pressure was for those areas, and then I checked the newer incremental reserves and I found they were approximately the same, say .3 of a B versus .4 of a B. So once again, qualitatively that gives me an idea of what to expect.

Q. And these instances where you did check were outside of the infill area?

A. Yes, they were.

Q. Okay. How many roughly?

A. I only did two.

Q. Only did two.

A. Uh-huh.

Q. All right. Were they near the infill areas or -- You've got some pretty big areas in between that Culpepper and the two project areas over to the east. Do you think they were good examples that were far away from these infill areas?

A. I checked over in the southeast federal units where I have good data.

Q. Okay.

A. Further away to the southwest, you will find that the parent-to-infill ratio sometimes is less than .4. So that meant that I could not use that particular crossplot to evaluate that area.

Q. Okay, on Exhibit Number 7 Mr. Kellahin used the word that I need to check here. The word "fairway" was utilized. Do we actually see a fairway, or have we got so used to that terminology in the Basin-Fruitland Coal -- Do you want to expand on that a little bit?

A. There are areas where the Dakota is more productive than other areas. There are geologic reasons for that, which Mr. Christiansen will testify. He's going to show you why that is the case.

Q. Okay. Then he will get sort of a preview of where I go.

Okay, on your -- continuing on Exhibit Number 7, the word "acceleration" here and "incremental", that acceleration -- and you have indicated in the Culpepper and also the 27-5 unit, now, the Culpepper looks like it's a 50-50 split. Now, when I assume the word "acceleration", this is production that could be -- the dark blue represents production that could be, over time, produced from the two infill -- I mean the two wells on a proration unit. Am I assuming that right?

A. That is correct.

Q. Okay. But that's quite a split for that 27-5 unit. That's to a 50-50. That looks kind of like a -- what, a third to --

A. It's about two-thirds, yes. Yes.

Q. Did wellbore stimulation play into any of these calculations? What I mean by that, the stimulation on the existing wellbore within a quarter section? Did you see some pressures -- What is the stimulation program for a Dakota well?

A. Right now, Burlington has adapted a slickwater technique, usually about 40,000 pounds of sand, which is nothing new to the Basin. In fact, many of the original 320-acre wells were stimulated in that manner.

Q. Now the stimulation program over time -- And the Dakota has been producing what, since the late 1940s, early 1950s?

A. (Nods)

Q. And then -- That's a yes, he shook his head yes, okay.

A. Yes, sir.

Q. Okay. And then the big infill push, what, back in the mid-1980s, early 1970s, is that when we start seeing --

A. 1980 through 1982 was where a large number of increased density or infill 160 acres were drilled.

Q. Okay, between those two periods, what kind of stimulation did we utilized? The original and then the infill period?

A. Okay, prior to the infills, it was mainly slickwater jobs. And I'm generalizing because certainly there are going to be many exceptions.

Subsequent to the infill order in 1980 a large number, but not all, were done with either a linear gel or a cross-linked gel system that pumped more sand.

Q. Is that kind of stimulation technique going to affect the pressures overall within the reservoir or these infill areas?

A. No.

Q. In other words, we didn't get connections, or we didn't see where the fracs came together and gave you a false reading in the pressure, a lower -- of course, that would give you a lower pressure, right?

A. We did not see any circumstance like that. Particularly the jobs that we pump are so small, the sand does not go into the reservoir extensively. So there would be no reason to expect to see any type of stimulation jobs interfering with each other.

EXAMINER STOGNER: Mr. Chavez, any questions?

EXAMINATION

BY MR. CHAVEZ:

Q. Yes, Mr. Kean, on your pie chart -- and is this Tab 4 or is this Exhibit 4?

MR. KELLAHIN: It's Tab 4.

Q. (By Mr. Chavez) Tab 4. The data that was used to construct this was information that you had at which time, after the pilot testing or before the pilot testing?

A. The EUR data originated before the pilot testing. The gas-in-place data is subsequent to the pilots. We took the data from 27-5 and Culpepper adjusted our gas-in-place model, and that's the number that we see there.

EXAMINER STOGNER: If I may, I'm going to ask you to treat Mr. Chavez rudely at this point. When he asks you a question, if you could direct your answer toward the microphone, or at least back toward Kellahin and not directly to Chavez.

So I'm going to give you permission to treat Mr. Chavez rudely at this point.

THE WITNESS: Yes, sir, Mr. Examiner.

(Laughter)

MR. CHAVEZ: Mr. Stogner treats me like that all the time, so --

(Laughter)

Q. (By Mr. Chavez) You testified, I think, that the differences between your pilot projected production and your actual production were due mostly or solely to the differences in pressure; is that right?

A. Primarily to the difference in pressure. Primarily to the difference in pressure.

Q. Do you have a -- When you say primarily, the reason I was asking was, I think, leaning on what Mr. Stogner asked, was there any difference in the way these wells were perforated or fractured that might have contributed to the differences in the anticipated production range?

A. No.

Q. Were any new layers of the Dakota perforated and fractured in the pilot that were not perforated and fractured in the original wells on that GPU?

A. No, they were not.

Q. Under Tab Number 6, when you say that the pilot results are transferable to the pool, your discussion seemed to indicate that this could be used as a model, for example, for an operator who, if I understand this correctly, might be considering drilling extra wells within a Dakota GPU.

They could look at the infill-to-parent EUR ratio that they currently have and then make an estimate as to what qualitatively new reserves may be available; is that correct?

A. Yes.

Q. So when you say they're transferrable, you're basically -- you're not really saying that you've proved that these are applicable across the pool, it's just that you've got a model which you think operators may be able to make some determinations -- is that right or -- How do you say they're transferable?

A. We do have a relationship based on the pilot areas that appears to be transferrable to the other parts of the pool.

Q. Did you use your summary data -- The way this chart is put together, it looks like you used the summary data from those three different pilots to come up with this chart; is that correct?

A. I'm not sure that I understand what you mean by "summary data".

Q. Well, let me put it this way: Did you take each of the pilot wells that were drilled and try to match them to this curve to see how valid that match was?

A. No, we did not look at the well level.

Q. So the validation of -- You don't really have anything to validate this curve, when we look at, say, even current wells that are being drilled to be the second well on the tracts, whether it's your third or fourth; is that correct? There's nothing that you've done to validate this curve?

A. The data that is plotted on the curve from the Y axis is based on reservoir simulation, which is based on the results that we obtain from those three pilot areas.

Q. Okay, so it still remains to be seen how effective this is as a tool to make these types of determinations as far as incremental gas; is that right?

A. Certainly, and this is a qualitative look.

Q. Given that chart, am I on the right track if I were to say that it would appear that those tracts which might be less productive, in a sense, would be more likely to be infilled in the sense that lower productivity wells don't drain as much of an area; is that -- Am I heading the right way when I say that?

A. You're saying that -- areas where EURs are lower?

Q. Yes, I guess that would be the case, yes.

A. Okay, so an area where the EUR is lower, then you would expect a smaller drainage area.

MR. CHAVEZ: Okay, that's ultimately where I was headed with that.

Okay, that's all I have, thank you.

EXAMINER STOGNER: Any redirect, Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Does anybody else have any questions of this witness?

You may be excused, Mr. Kean, I don't have any at this time. Thank you, Mr. Kean.

MR. KELLAHIN: I call our geologic witness at this point.

Mr. Stogner, Mr. Christiansen will testify concerning the exhibits found behind exhibit Tabs 10, 11 and 12.

GLEN E. CHRISTIANSEN,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. For the record, sir, would you please state your name and occupation?

A. Yes, Glen Christiansen, I'm a geologist with Burlington Resources.

Q. Mr. Christiansen, where do you reside?

A. Farmington, New Mexico.

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

A. Yes, I have.

Q. What has been your role as a geologist on the Burlington team that has studied the Dakota and come to the conclusions about increasing well density?

A. Essentially to supply the geologic input for the ongoing work which you'll see here, in terms of gas in place, petrophysical models and some of the other geologically supported --

Q. As a geologist, do you concur with Mr. Kean when he testifies that he now believes it's appropriate to increase the well density in the Basin-Dakota Pool?

A. Yes, I do.

Q. When we look at Exhibit Tab 10, let's turn behind that tab, and if we were to look at any of your displays and find that display that helps us start building an understanding of what you've done, would it be this Dakota original-gas-in-place map?

A. Yes, it would be.

Q. Before we talk about how it was prepared, describe how the gas-in-place map has been used.

A. The gas-in-place map is pretty much the key geologic exhibit that I'll be showing you today. It is essentially the summation of our petrophysical model. It has been revised and calibrated to match the pilot data that we've gathered in the two pilots, and it will also be used in later maps, as you will see, that will help us -- give us another tool where we can adequately assess the applicability of the infill ruling that we're looking for right now.

Q. All right. Let's talk about the data that you utilized to prepare the map. What did you use, and what was its source?

A. The source for this map that we see right here was approximately 700 wells across the developed area of the field. We developed a petrophysical model to determine the hydrocarbon saturation within each well, calibrated that with the formation volume factor and then contoured it for the resulting map that you see here.

Q. All right. In simplest terms, if you have constructed a Dakota original-gas-in-place map that is accurate to the best of your ability, and that if we subtract from that map what is forecasted to be recovered by the first and second well in a spacing unit, then we will be able to see how much original gas in place is left that may be available for recovery by the third and fourth well; is that a fair way to look at this?

A. That is correct, and you will see that shortly.

Q. All right, describe for us the color code. How do we read the color code?

A. The map is contoured on half a BCF per 160. The cooler colors and the blues are you low values, and your warmer colors to the reds are you higher values. I believe the highest value is somewhere around 6 to 7 BCF per 160.

Q. Okay. Have you integrated Burlington's pilot project area data into your map?

A. Yes, we have.

Q. When the reservoir simulator engineer, in the pilot assumption, has forecasted a certain rate of production at a certain pressure and you have drilled your pilot wells and find out that you have a higher rate and a higher pressure, what have you had to do, if anything, to your gas-in-place map to match the reservoir engineering data?

A. For the higher pressures that we did measure in our pilot areas, the ultimate-gas-in-place number had to go up.

Q. And why was that so?

A. With increasing pressure you can concentrate more gas in place.

Q. What does that tell you about the existing well density?

A. It is inefficient in maximizing the recovery of the gas that's in place.

Q. And as a geologist, what do you recommend the Division do?

A. Grant the proposal to increase the density of wells up to the four.

Q. All right. Let's move past the original-gas-in-place map -- Let me ask you this before we leave: Have you adjusted the original-gas-in-place map to take into account the results of the pilot simulations?

A. Yes, I have.

Q. So we're looking at a revised map that is your current best map on gas in place?

A. That is correct.

Q. All right, let's look at the next map. What are we looking at?

A. This -- Mr. Kean had talked earlier about the estimated ultimate recovery for the Dakota Pool. This is essentially a map of that data. It's the 5000-some-odd wells in the Basin. The contour interval is gridded such that we're essentially averaging the parent and infill wells across a section.

This map defines what is probably the developed area of the field.

Q. All right. If we take what we estimate to be the ultimate recovery under the current development for these wells, how do we read the map to see what's left as a resource? In other words, the estimated ultimate recovery is displayed how?

A. The estimated ultimate recovery here is shown in BCF --

Q. Okay.

A. -- contoured on 1-BCF contour intervals. And so for instance, in 27-5 the estimated ultimate recovery on a township level ranges anywhere from one to 2 BCF per well.

Q. All right. Now, if I take the original-gas-in-place map, I subtract what the current wells are going to do for ultimate recovery, do you have a display that will show me now the remaining gas after we do that?

A. Yes, that is the next exhibit.

Q. All right, let's look at this. Tell me how to read this map.

A. This map is the Dakota remaining gas in place. It is essentially the result of subtracting the estimated ultimate recovery from the gas-in-place map that we saw at the very first. This map is contoured on 1 BCF per 160. It is only colored on a BCF and greater, to kind of highlight the areas that we see the most potential with.

Q. All right, if I want to utilize this map and try to decide where to place my third and fourth well, if you will, and I have an interest in the 28-and-6 township that's in between the 27-and-5 and the 28-and-7 -- do you see that?

A. Uh-huh.

Q. -- would I want to put my well in the blue area or in the darker tan area?

A. The darker tan area is the areas of higher remaining gas in place.

Q. All right, sir. All right, let's go to the next display. It's entitled "Dakota 160-Acre Infill Pressure". What's the point of this map?

A. This map, similarly to the last map, is another one of these tools that we can use to extrapolate the data that we have from our pilots across the Basin. This map was generated from data that was published in an SPE paper back in 1983, and it's essentially the average pressure for the 160-acre infills across the township level.

What you see here is, the warmer colors and the light tans are your higher surface pressures for your infills. The cooler colors, the blues, are the lower pressures.

Q. All right. You've used the first series of maps that I can find within a township the better opportunities for remaining gas recovery, and now I have a map I can look at to show me where the higher pressures are. And let's again look at the 28-and-6 township. What's the significance of that color code?

A. In that area what we see is a higher surface pressure for the infill 160s. We also saw a higher remaining gas in place, suggesting that that area would be amenable to the increased density.

Q. All right, sir, I can use both of these maps -- if I'm Tommy Dugan out there wanting to use your work product, then I can use these maps if I have an interest in 28-and-6 and figure out where I ought to be drilling my infill wells?

A. They both are tools to do that, yes.

Q. Okay, let's turn to the next display and have you identify that for us.

A. I should have probably stated on the previous map, we do have a cross-section line going across there from northwest to southeast. This next slide is that cross-section.

This slide has one well in each of the three pilot areas. It illustrates the different members of the Dakota formation that we are pursuing. In each of the three areas we have, different members of the Dakota are the predominant producers. One other thing you can get from the logs that are shown is the relative depths of the Dakota in the different pilot areas.

Q. The Dakota is subdivided into these four possible intervals of productivity?

A. Yes, it is. The nomenclature, of course, in the Dakota is always in change, but in terms of consistency Conoco and Burlington both use this same nomenclature for the Two Wells as the uppermost member of the Dakota, the Paguate is the next lower member, followed by the Cubero and lower Cubero.

Q. All right, you have subsequent illustrations that will show us Burlington's conclusion about how these four intervals relate one to another as we move throughout the pool?

A. Yes, I do.

Q. All right, we'll save that discussion for later then. Turn to the next display. We're looking at a Dakota structure map. Is structure a significant component for making a decision concerning well density?

A. No, it's not.

Q. And why not?

A. As you can see from this map, it is -- the Basin itself is a fairly monoclinal dip to the northeast. There are no major structural features within this mapped area, and therefore it would not require any type of subdivision based on structure.

Q. All right, let's turn to Tab 11. When we look behind Tab 11, what are we about to look at and why are we looking at it?

A. The next four slides that you'll be seeing are essentially the building blocks for the gas-in-place map that we saw on the very first slide.

Q. Okay, let's go through each one of those, and explain to us the points of significance to you as a geologist.

A. The next series of maps are going to be bulk volume hydrocarbon maps showing essentially -- contouring the feet of hydrocarbon present in the reservoir. If you want to think of it as a net pay map, that's probably a pretty good way to think about it.

The first map is the Two Wells map. It is contoured on quarter of a hydrocarbon feet, and what you see is the main trend of the Two Wells that runs from northwest to southeast. The 27-5 and 28-7 Units lie in the heart of this trend, and the Culpepper pilot area lies just on the southwest edge.

Q. All right, let's look to the Paguate bulk volume hydrocarbon map and see how that distribution is apportioned on the map.

A. The Paguate is the next unit down, and what you'll see here is, it's a fluvial deltaic system, generally prograding to the northeast. In the Culpepper pilot area the Paguate is the main producing unit there. It is absent in the 28-7 and 27-5 Unit.

Q. Okay, the next display?

A. The next unit down is the Cubero. This unit, similarly to the Paguate, is only present in the eastern half of the Basin in 28-7 and 27-5. It is absent in the Culpepper Pilot area.

Q. Okay, and the last display?

A. Okay, the last display is the lower Cubero. It is a fluvial system, generally with progradation to the northeast as well. It is an important producing member in the 27-5 and 28-7 Units, less so in the Culpepper pilot area.

Q. All right, and these displays in combination, then, were utilized by you to create the gas-in-place map?

A. That is correct, essentially summing these last four slides and correcting for bulk formation volume factor gives you the gas in place.

Q. Let's turn to Exhibit Tab 12, and let's do this in reverse order. If you'll take all the plastic overlays, turn past them and get to the last page of Exhibit Tab 12, you're going to have a paper copy of what is described as Dakota remaining gas in place.

A. That's right.

Q. Is this the same map we looked at a while ago?

A. Yes, it is.

Q. All right. What are you trying to illustrate with this section of the exhibit book?

A. One of the things we want to know is what is controlling both the Dakota remaining gas in place across the Basin, and also we'll look a little bit later at what is controlling the infill pressure that we see across the Basin.

Q. So Exhibit 12, as we're now looking at it, is going to give us a way to look first of all at -- and I'm doing these in reverse order, I'm starting with the Dakota remaining gas in place.

A. That's correct.

Q. We're going to work backwards and start putting these plastic overlays, and the point is to see how the gas in place is apportioned among the four productive intervals?

A. That's correct, I have taken essentially the outlines of the previous bulk volume hydrocarbon maps that we saw and just made them into transparencies so we can see where the hydrocarbon saturation is located and how it relates to the remaining gas in place.

Q. All right, do that for us.

A. So the first overlay you could take over would be the lower Cubero. That's our lowestmost member. What you can see is, it overlies that southeast portion of the Basin and a little bit up into the Culpepper pilot area.

Subsequently, if you take the Cubero member and overlay it, you can see it lies entirely on the eastern portion of the Basin, also in the same 27-5, 28-7 pilot areas.

What really is interesting is when you take the Paguate map and overlay it. You'll notice it is the lone formation that produces the most of the gas in the southwest portion of the study area.

And then the Two Wells is the final top member.

So what you can see is, in the areas where we have multiply stacked members of the Dakota we have higher remaining gas in place.

Q. As a geologist, do you think it's necessary and appropriate to try to subdivide the pool into different pools and develop different spacing for this pool?

A. No, I do not.

Q. What is the best way to access the additional opportunity to increase ultimate recovery in the pool?

A. The increased density up to the four wells per 160 would allow you to produce that remaining gas.

Q. And in those areas of the pool where you don't have substantial overlay, it's your preference to leave it to the operator to make the decision on whether he spends his money on the additional well or not?

A. Yes.

Q. Let's look at how pressure affects this. If you'll turn again backwards, look at the hard paper copy of what is marked "Dakota 160-Acre Infill Pressure". Again, we're looking at the same display we looked at a while ago?

A. That is correct.

Q. All right. Take us through the overlays on pressure and describe for us what you see.

A. Again, what you'll see is similar responses as you saw in the last series of slides where the lower Cubero, Cubero, overlie each other in the higher-pressured areas if the Basin, and it is the Paguate that is responsible for the large majority of the lower pressure that you see on the western side of the Basin.

The Two Wells almost defines that northwest-southeast trend that you see separating the blues from the yellows on the pressure map.

Q. There seems to be a substantial significant conclusion between the remaining gas and higher pressure. In other words, if I'm in an area of higher remaining gas, I'm also in an equivalent area of higher pressure?

A. Yes, that's correct.

Q. They're just linked together, aren't they?

A. And what does that tell you as a geologist concerning well density?

A. That in those areas the current spacing is insufficient to drain those reserves.

MR. KELLAHIN: Mr. Catanach -- I mean, Mr. Stogner --

EXAMINER STOGNER: Yes, Mr. Carr.

(Laughter)

MR. KELLAHIN: Just seeing if you're awake. Mr. Stogner, we move the introduction of Mr. Christiansen's Exhibits 10, 11 and 12, and that concludes my examination.

EXAMINER STOGNER: Exhibits 10, 11 and 12 will be admitted into evidence at this time.

Are you the person I should ask about this fairway question that I had earlier? Is this more of a fairway geology?

MR. KELLAHIN: I'm so sorry I said that.

EXAMINATION

BY EXAMINER STOGNER:

Q. Well, it looks like the Two Wells is a fairway *per se*.

A. Yeah, I think it's a relative term. I think the way that Mr. Kellahin used the term fairway, I would use as the area of the developed portion of the field -- of the pool. There is -- As you can see from the gas-in-place map, there are reasons why there are better wells in some places than others.

EXAMINER STOGNER: Mr. Chavez, a point of reference. Are these recognized formations with the Division in the Aztec Office, the Cubero, lower Cubero and Two Wells?

MR. CHAVEZ: Mr. Stogner, the geologic nomenclature is not always agreed on by geologists, but these are acceptable nomenclatures for those formations, the discussions we've been having with the operators in the area.

EXAMINER STOGNER: So you or your geologist in the Aztec Office have no problem with the terminology presented today?

MR. CHAVEZ: No, sir.

Q. (By Examiner Stogner) Okay. One of the things that stands out whenever I'm looking at Tab 10 -- this is the cross-section -- in the San Juan 28-7 Unit, which is the middle area for the infill, the Paguate is not shown to be productive. Is that accurate, or is sometimes the Paguate produced over in that area, or what's the phenomenon going on here? Because that looks pretty thick in that 28-7.

A. The unit is present there. I believe, though, that when you look at the density log, which is the black curve, you'll see no effective porosity there. So essentially it's not effective reservoir.

Q. Where's the breakout or breakoff? Where does it -- Well, it shows, I guess, on the overlays.

A. Right, and that's the key, is when you look at the bulk volume hydrocarbon, you can see where the pay is and where it is not.

Q. Now, that took me by surprise about the Paguate and the Cubero being that separated. Okay, again, I think you mentioned the lower Cubero was an alluvial system, and what's the Cubero again? Is that --

A. A fluvial -- The Cubero is actually more of a marine-dominated unit, shoreline-type fluvial deltaic also.

Q. When you say a shore --

A. Nearshore marine.

Q. Nearshore marine? How about the Paguate?

A. It's very similar.

Q. Just laid down at different times, obviously.
A. Exactly.
Q. And how about that Two Wells, what's its primary deposition?
A. It's a marine, also a marine unit. Some people have interpreted it as offshore-type bar system, other people have interpreted it as a shoreline system. Generally as you go up through the Dakota you become more and more influenced by marine processes.
Q. Okay, when I look at the cross-section again, you've got the Cubero and then it abruptly ends. Did it not deposit over time, or was it eroded out by the Paguate, or what happens between the two?
A. More than likely, the way I would interpret it is that there was an area of nondeposition that essentially had that pulse of sediment come out from the southeast portion and was not deposited in the northwest.
Q. Okay, now what separates the Paguate and the Two Wells?
A. It's a kind of a silty member that you would include within the Two Wells. It is not considered pay.
Q. And what is that, a deep-water marine --
A. It is a marine-type unit, yes --
Q. But it's --
A. -- offshore-type unit.

Q. Are these the only four recognizable pay zones, or is there any other pay zones within the Dakota Pool?

A. The lower Dakota is a more conventional-type unit, but is generally water-bearing.

Q. Pardon me?

A. Water bearing.

Q. Oh, water bearing.

A. Yeah, and you can see that in the 28-7 well there, that lowermost sand. It's a very discontinuous sand and generally is water-wet.

Q. Okay, my question is, I guess -- let me rephrase it. Is there any pay zones below the lower Cubero, or is that the base of the Dakota Pool?

A. Well, formally -- if I understand it, formally the base of the Dakota Pool is 400 feet below the Greenhorn or base of the Greenhorn.

Q. And where is the Greenhorn, if I was to mark it on this cross-section?

A. The cross-section is actually hung on the base of the Greenhorn. So that dark dashed line that you see is the base of the Greenhorn.

Q. Now, what is the base of the Dakota?

A. The base of the Dakota would geologically be defined by the top of the Morrison.

Q. Now, is that indicated here?

A. It likely is there at the base of the sand. The top of the Morrison would be just above 7400 on that 28-7 well, would be where I pick it.

Q. Okay. Now what's between that Morrison and the lower Cubero, what kind of a stone do we have?

A. In some instances you have high-porosity, high-permeability-type sandstone, but it's typically wet, and in other places that sandstone is absent and you're essentially -- the conventional Dakota is sitting on top of the Morrison.

EXAMINER STOGNER: Mr. Chavez?

MR. CHAVEZ: I'll step over to be sure we're not having the same problems, if that's okay.

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Christiansen, under Tab 10, your Dakota original gas in place, you said you revised that on the basis of the pressures you got in the pilot project; is that correct?

A. That is correct, matched the simulation gas in place.

Q. Would that be only to consider the areas between existing wells that already -- you had the pressure zone? Or how were you able to do that when you had original pressures in the Dakota already and nothing changed for you? Did those also change for you?

A. Those also changed --

Q. In what way did the --

A. -- if I understand your question correctly.

Q. Well, what I was trying to get at here was, I could understand how you might want to revise current gas in place, based on those pressures, but original gas in place, which might be based on original pressures from the original well on 320 or the infill 160 well, when those area available to you, how does 80-acre pressure change those original pressures, change the original gas in place?

A. The way I would explain it, I guess, is that you had -- we had our simulation runs that showed -- Let's see if I understand this right. Is what you're -- Let me see if I'm -- rephrase your question here. Since you're interested in knowing why the original gas in place is changed, if we knew what the 320 pressures were to begin with, is that --

Q. Yes.

A. -- is that right? Okay. I believe one of the reasons is that we didn't have an adequate pore volume in the original gas in place also in our first version, that our pore volume was increased due to the simulation.

EXAMINER STOGNER: Mr. Christiansen, you're beginning to fade away a little bit.

THE WITNESS: Oh, okay.

EXAMINER STOGNER: If you can speak up a little here.

THE WITNESS: The original gas-in-place model that we had was a function of both pressure and pore volume. The subsequent map that you see here has been revised with respect to pore volume that was needed to match the simulation and production runs that we were seeing from our pilot wells.

Q. (By Mr. Chavez) Okay, those pore volumes are different than what were derived from the original models on the 320 and the 160 infill then?

A. Yes.

Q. To what degree did those pore volumes contribute to this change in the original gas in place?

A. The pore volume was greater -- was -- the pore volume needed to be increased to match the simulation runs. Therefore the gas in place was increased.

Q. Okay. Were those -- You had to change an element of your model in the simulation run. Did you have any other data to support that change in the pore volumes, other than you needed to change it to adjust to fit your pressures?

A. Right. The amount of pore volume that was needed was not -- did not exceed any type of petrophysical measurements that we have in the Dakota. It was within the limits of what we say the porosities were, all within the range that we would expect for the Dakota.

MR. CHAVEZ: Thank you, that's all I have.

EXAMINER STOGNER: Any redirect?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Anybody else have any other questions of Mr. Christiansen? You may be excused at this time. Shall we take about a ten-minute recess?

MR. KELLAHIN: Yes, sir.

(Thereupon, a recess was taken at 3:15 p.m.)

(The following proceedings had at 3:40 p.m.)

EXAMINER STOGNER: Okay, Mr. Kellahin?

MR. KELLAHIN: Mr. Stogner our next witness is Mr. Jim Kolesar. He spells his last name K-o-l-e-s-a-r.

MR. KOLESAR: Correct.

MR. KELLAHIN: He's a petroleum engineer and did the reservoir simulation for Conoco on their 28-and-7 pilot project.

JIM KOLESAR,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. For the record, sir, would you please state your name and occupation?

A. Okay, my name is Jim Kolesar and I'm a reservoir engineer for Conoco.

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

A. I have not.

Q. Summarize for us your education.

A. Okay, I have a bachelor of science degree in biochemistry in 1978 from the University of Pittsburgh, a mining engineering degree from the University of Pittsburgh in 1980 and a master's in petroleum engineering from Penn State in 1985.

Q. What is your current responsibilities for Conoco concerning the Application that's before the Division this afternoon?

A. My responsibilities concerning the Application that's before the Division include calibrating our model with the data that we acquired from our pilot wells and then forecasting the model to predict how those wells would perform.

Q. Are the exhibits we're about to look at your work product, Mr. Kolesar?

A. Yes, they are.

Q. And are the opinions you're about to express as a petroleum engineer your own professional opinions?

A. Yes, they are.

MR. KELLAHIN: We tender Mr. Kolesar as an expert petroleum engineer.

EXAMINER STOGNER: Mr. Kolesar, that was a BS in biochem and a BS in mining --

THE WITNESS: Mining engineering.

EXAMINER STOGNER: I'm sorry?

THE WITNESS: Mining engineering.

EXAMINER STOGNER: And that was a BS or BMS?

THE WITNESS: BS.

EXAMINER STOGNER: BS. So qualified.

MR. KELLAHIN: His exhibits are going to be 13, 14 and 15, so if you'll turn with me to Exhibit Tab 13, turn past the tab, let's go directly to some of the critical points about your study.

Q. (By Mr. Kellahin) Did you have sufficient data?

A. Yes, we did. One of the conclusions that Conoco reached in their pilot program was that sufficient data was acquired to properly assess the need to infill the Dakota in the 28-7 Unit.

Q. Okay, describe for us the basis for that conclusion.

A. Conoco drilled a total of 15 pilot wells, and those wells were drilled in two groups. The initial group consisted of six wells that were drilled across the unit and the second group consisted of nine wells that were drilled in a very focused area of the unit. And in each of those wells we acquired data.

In the original six wells we acquired open-hole logs, zonal pressures, core data in Two Wells and ran some specialty logs to look for fracturing.

In the second group of nine wells we ran cased-hole logs and acquired bottomhole commingled pressures.

Q. Have you conducted your work on behalf of Conoco independent and separate from the work being done by Burlington in their pilot areas?

A. Yes, I have.

Q. Let's turn to the next display. What have you concluded about the appropriateness of increasing the well density?

A. Okay, all the data that we have from our pilot wells points toward the need to increase the density up to four wells per 320 GPU.

Q. What did you find, in a summary fashion, that supports that conclusion?

A. There are several facts that support that conclusion. One is, as Jack showed earlier, that pilot rates and pressures were higher than expected, and that required that we increased the amount of gas in place in our 28-7 model. And with more gas in place, there was more gas left in place for the 80 acres to target.

Another reason that I come to that conclusion is that the Dakota formation is a very tight formation, it's layered, and it's laterally heterogeneous, and that results in a very low recover factor in the 28-7 unit.

Q. Let's talk about your statement where you found increased rates and pressures required you for your own work to increase the original gas in place in your area.

A. Okay.

Q. Now, Mr. Chavez was asking the last witness about that activity. Did you increase the original gas in place and still honor the original pressure data you had for the parent well and for the infill well?

A. Yes, as I'll show in a few slides, the pressure that we used for the initial pressure in the model was based on data that we extracted from *Dwight's*, and it represents the average pressure at the time that the 320 wells were drilled, and that was a fixed, you know, given, that we did not change in the model. What we did change in the model was the pore volume, to increase the gas in place.

Q. Was the pore volume changed to such a magnitude that it exceeded reasonable engineering and geologic expectations in the reservoir?

A. No, not at all.

Q. All right, let's look at the next display. Can we apply, in your opinion, the results from the pilot project to a poolwide decision on well density?

A. Yes, we can.

Q. What supports that opinion?

A. As this slide shows, there are two facts that support that opinion. The first is that our model results are very consistent with Burlington's model results. Our calibrated 28-7 pilot model predicts an EUR for 80-acre density wells of 1.25 BCF, and that's very much in line with what Burlington predicts for their 27-5 unit.

And it's also important to note that our models were constructed totally independently, using different techniques and different assumptions by two different companies, yet we ended up with the same results.

And also, if you look at the gas-in-place model that -- the initial gas-in-place model that Glen presented, that was constructed independent of our 28-7 pilot results. And if you look on that map you'll notice that the gas in place in our pilot area, based on Glen's map, is 16 BCF per section. Calibrated, the gas in place for the calibrated model was 17.2 BCF per section. So again you have, using totally different techniques by different companies, arriving at the same conclusion.

Q. Let's turn to Exhibit Tab 14. What are we about to look at behind Exhibit Tab 14? What does this collection of exhibits represent?

A. Okay, the collection of Exhibits in Tab 14 represent the model, how it was constructed, how it was validated, and the forecast results.

Q. All right, lead us through that discussion.

A. Okay, this first exhibit shows the 28-7 unit, the outline of the 28-7 unit, and the 28-7 unit includes parts of 54 sections in 28-7 and 27-7. It contains a total of 201 active Dakota producers.

There's a typo in the next bullet: That should be 15. Of those 201 producers, 15 are pilot wells. All 320-acre Dakota locations are drilled. We currently have five open locations for 160s. Three of those are on our drill schedule and two of those are located in the southern part of the unit where the Dakota is not economic at this time.

And the blue box represents the pilot model; it includes 16 sections. And the green-hached area represents the interior of the model, and that's the place where I will extract the results from.

All right, why are you using Pilot Well 225E as the point in which you surround your model?

A. Okay, in the 225E well, we had hole core data, we had a full suite of open-hole logs, zonal pressures, and we ran an MRI to look for fracturing. Therefore we had a fairly extensive data set to base our model on.

Q. All right, let's look at the next page and have you describe this.

A. Okay, the next page shows an enlargement of the model area. Again, it's 16 sections. The red wells represent the Phase I wells, the original six wells. The blue wells represent the Phase II wells. And you'll notice, if you look at the interior four sections, that eight of the nine Phase II wells are contained in those four sections. And the yellow wells represent the existing 160- and 320-acre wells.

Q. All right, next display. Describe this for us.

A. Okay. As I mentioned, we centered the model on Well 225E to come up with our initial model description because of the data that we had on that well. The model itself is a 64-by-64 areal grid. It has three layers and one each for the Two Wells, the Cubero and the lower Cubero.

It has an initial pressure of 3184 at 7220 feet, which represents the initial reservoir pressure at the time that the 320s were drilled. And the calibrated model in those interior four sections had an initial gas in place of 17.2 BCF per section.

Q. All right, let's turn to the reservoir parameters.

A. Okay, this exhibit shows the reservoir parameters that were included in the model, and you can see the three layers represented by columns and the parameters represented by rows on this slide.

The first row, permeability, in the Two Wells is .014; Cubero .0105; and lower Cubero .0018. Permeability represents the ability of the gas to move, or a fluid to move, throughout a porous medium. And permeabilities in this range are very low, and so the gas has a difficult time migrating through the formation. In particular, if you look at the lower Cubero, .002 is extremely low.

The net thicknesses were derived from log data where we looked at cutoffs in the gamma-ray, resistivities and also in the porosity logs. And for a starting point we used an average porosity of .08 in each of those three horizons and a water saturation of 35 percent.

Q. All right, describe for us the slide that deals with the calibration of the models.

A. Okay, the method that we used to calibrate the model entailed forcing the model to honor the historical monthly volumes from the existing wells, from the time they were drilled, up through the end of 1999. And when we forced the wells to honor those existing volumes, that created a pressure distribution in the reservoir that we then compared with the Phase II pilot well data.

And it was necessary to make some adjustments in the model in order to match that pressure data. So we had to increase pore volume in places, modify permeability slightly, and also change some of the inter-block flow characteristics in order to make that pressure match.

The next step was to turn the model on to forecast mode and forecast the existing wells out to their economic limits. And we wanted to validate that the model was giving reasonable numbers when it was turned into forecast mode, so we compared the EURs predicted by the model with those predicted by decline curves. And after we were comfortable with the first three bullet points, then we turned on the pilot wells and forecast their performance.

Q. All right, sir, let's turn to the next display. Identify and describe this for us.

A. Okay, this display is a comparison of the model forecast for the existing 160- and 320-acre wells with the decline-curve forecasts through the year 2040. And up through the end of year 1999, the two curves overlay each other directly because we were forcing the model to honor historical data. We turned it into forecast mode in the year 2000, and you can see there's a very minor deviation, but it in essence is an excellent match between the decline curves and the model.

So we felt comfortable at this point that not only did the model do a good job of honoring pressure distribution within the reservoir, but it also did an excellent job of forecasting out the performance of the existing wells.

Q. All right, sir, the next display.

A. Okay, this next display compares the measured pressure, bottomhole pressures in our pilot wells, to the pressures in the model, in the cells containing the pilot wells. So you can see from this slide that our Phase II wells encountered a big pressure range. And from a low of -- on the far left of the graph, of around 1800 p.s.i. in Well 130E, to a high of close to 3000 p.s.i. in Well 190F. And you can just see there's an excellent match between the pressures predicted by the model and the measured bottomhole pressures in all of the pilot wells, and the standard deviation of the match was about .67 p.s.i.

Q. Okay, what happens next?

A. Okay, next was to turn on the pilot wells and to compare the performance, the predicted performance of the pilot wells with the actual pilot data. And the next three exhibits show a comparison of three wells.

The first well is 225E, and that is the well that we built the model around. It's the well that we had the longest flow period on and we also had most of the data on. And you can see that the model does an excellent job predicting the 225E rate.

On the next exhibit the 130E well was drilled in a low-pressure area, and it was one of our lowest-rate wells. And early on, because it was low pressure, you can see the 130E well had some trouble unloading the frac job. It peaked at a rate of about 450 per day and went on decline at that point, and then somewhere, 30 or 40 days on production, started loading up, and you can see the upward and downward cycles of the rate as the well loaded up and unloaded.

But the model also does a very good job of drawing the predicted forecast of going right through the middle of the data of the highs and lows for that particular well.

Q. All right, and the last production?

A. So the 130E represented a low-pressure, low-rate well. The next slide is -- represents the match the pilot had with the 225F well, which is one of the higher-pressure, higher-rate wells. And again, you see that the model does a very good job predicting the initial performance of 225F.

So in general, the model is able to predict the rates out of low-pressure, low-rate areas, and also does a very good job in high-pressure, higher-rate areas.

Q. At this point, what is your confidence level about the accuracy of the model?

A. I feel very comfortable with it.

Q. So now you're ready to allow it to forecast, what happens?

A. Yes.

Q. Let's do that --

A. Okay.

Q. -- show what happens.

A. Okay, the next three exhibits result from letting the same three pilot wells continue to produce out through January of 2040.

And in the 225E well, the model predicts a recovery of about 1.4 BCF.

And on the next exhibit, the recovery for the 130E, which was a lower-pressure, lower-initial-rate well, is just slightly under 1 BCF.

And in the next slide the recovery for the 225F, which was a higher-pressure, high-initial-rate well, is slightly under 2 BCF.

And the slide after that summarizes the data from the remaining pilot wells that I did not include charts for. And the range of recoveries, then, goes from slightly under 1 BCF in the 130E well to a maximum of slightly under

2 BCF in the 225F well. The arithmetic average of all the pilot wells is 1.25 BCF.

Q. Are the forecasts for the production of these wells predicated on them being the third and the fourth infill well, if you will?

A. No, they are not.

Q. So what are we modeling?

A. The pilot wells in the 28-7 unit were drilled over a two-month period, so they basically all came on at the same time.

Q. So are we forecasting what the pilot well will do, or what these wells will do, on a density pattern that's the equivalent of the 80-acre density? Is that what we're doing here?

A. Yes, it closely approximates 80-acre density in the top two sections of those interior four sections, yes.

Q. I don't care what the model does about the parent well and the first infill well, I want to know what the model will show me if I drill the third and the fourth well. Is that what I'm seeing here?

A. Yes.

Q. Okay. And under this scenario, then, at least for the modeled area, we know it is profitable to drill the third and the fourth well?

A. Yes.

Q. There is sufficient recoverable gas, incremental gas, that makes this profitable?

A. Yes.

Q. All right. Let's turn to Exhibit Tab 15. Now, have you made the same assumptions when we get into this section of your display about utilizing the opportunity to drill a Mesaverde Dakota downhole commingled wellbore? Mr. Kean in his presentation earlier this afternoon demonstrated his conclusion that Dakota development will take place as a tag or a tail to a Mesaverde well. Do you come to that same conclusion?

A. Yes, and I have a slide that addresses that.

Q. Okay, all right. Do you see a substantial opportunity to drill stand-alone Dakota wells?

A. As will show in a few slides, the economics of the stand-alone Dakota wells in the 28-7 Unit look good. They would look much better if they were commingled with the Mesaverde.

Q. Let's talk about Exhibit Tab 15. What are we about to see when we look at this portion of the exhibit book?

A. Okay, one of the important components of determining how economic an infill program is, is to quantify how much of a well's recovery is due to the incremental production and how much is due to accelerated production.

Q. There's certainly no incentive for Conoco to drill wells that do nothing more than substantially accelerate the rate of recovery that can be achieved with existing wells?

A. There is not.

Q. That's not good business sense, is it?

A. No.

Q. So what you're looking for is sufficient incremental gas --

A. That's correct.

Q. -- that you would not otherwise recover?

A. That's correct.

Q. And what have you concluded?

A. This graph shows the relationship of the acceleration component to the incremental component in our 28-7 pilot model. And on the left-hand Y axis we have gas recovery -- this is for the interior four sections of the model -- versus time.

And the acceleration component is shown as the area between the blue and the green curves.

The incremental component is shown as the area between the red and the blue curves.

And visually if you look at these two areas, you can see that the incremental component is overwhelmingly larger than the acceleration component.

Q. All right, let's turn to the next display.

A. So if you apply that -- Did you have a question first or --

Q. No, sir, go ahead.

A. Okay. So if you apply that ratio to a per-well basis you end up with, of that 1.2 BCF total recovery per 80-acre infill well, that 1.05 BCF is incremental reserves or 84 percent of that total, and .2 BCF are accelerated reserves or 16 percent of that total.

Q. All right, sir, next slide.

A. Okay, the next exhibit shows the benefits of drilling infill wells in 28-7 Unit. If you look at the chart on the left side of the page, it shows the initial gas in place in the model of 17.2 BCF per section. The model predicts that the existing wells will recover 6.1 BCF or 36 percent, which is shown on the right side.

By drilling four additional wells per section, you increase the recovery to 10.3 BCF, which increases the recovery factor to nearly 60 percent.

Q. All right, make sure I understand. The 6.1 BCF, is that included in the 10.3?

A. Yes.

Q. All right.

A. So the four pilot wells will recover a little over a BCF each, so six plus four gets you to the ten.

Q. I got it. What's the next portion of the slide show?

A. The right half of the slide shows that the recovery is increased from 36 percent with the existing density to nearly 60 percent by drilling four additional wells per section.

Q. Okay, let's look at the next slide.

A. Okay, this exhibit shows the benefit of those additional four wells per section on the abandonment pressure.

Initial pressure in our model is 3184. Based on a 6.1-BCF-recovery per section with existing wells, that lowers the pressure to 2047, so there's -- at the economic limit of the existing density there's still quite a bit of pressure left in the reservoir.

By drilling four additional wells, you lower that pressure, that abandonment pressure, to 1300.

Q. All right, let's look at the economics, if you'll turn to the next slide. Identify and describe this for us.

A. Okay, this slide shows the economics for the average 80-acre infill well in the 28-7 Unit. And the assumptions that went into the economic analysis included a single Dakota completion, so it's not commingled. The incremental reserves are 1.05 BCF per well. I did not account for acceleration in these economics. Well costs were $650,000, operating costs of $500 per month, I used a flat $2.75 gas price and a 9-percent discount rate.

And those assumptions resulted in a discounted after-tax PI of 1.8, 1 being break-even, an after-tax discounted NPV of $351,000 and a rate of return of 69 percent. So the economics were very robust.

Q. Let's talk about the next slide and have you discuss and describe how you think the Dakota development is going to take place in companionship with the Mesaverde.

A. Okay. To date, Conoco has identified 117 potential 80-acre completion locations. And if you apply the same single-well numbers to those completions, you end up with incremental reserves of about 123 BCF in the unit, accelerated reserves of 23 BCF and total reserves of 146 BCF.

And we estimate that approximately 75 percent of those 117 completions, or roughly 85 wells, will be commingled with the Mesaverde.

Q. Can you give us a generalization about how many of these wells we might see drilled in the reasonable, foreseeable future? We're doubling the opportunity for wells. Are we going to see an explosion of drilling activity, if you will, if the rules change?

A. Okay, this year Conoco will drill between 80 and

85 new wells in the Basin. And we anticipate that we will continue to drill the same number of wells over the next few years. And the reason for that is that we're limited by the number of rigs, available rigs, we're limited by the number of completion crews. And so we do not expect to see any increase in our number of new drills over the next few years as a result of these locations becoming available.

Q. Do you see any problems, as a petroleum engineer, if the Dakota rules are made substantially the same as the Mesaverde wells?

A. I do not.

Q. Do you see the remaining opportunity for both those pools to be accessed by wells that are drilled as commingled wellbores?

A. Yes.

Q. That's going to be the future of this activity, is it not?

A. Yes.

MR. KELLAHIN: That concludes my examination of Mr. Kolesar, Mr. Stogner.

We move the introduction of his Exhibits 13, 14 and 15.

EXAMINER STOGNER: Exhibits 13, 14 and 15 will be admitted into evidence.

Thank you, Mr. Kellahin.

EXAMINATION

BY EXAMINER STOGNER:

Q. Were you on this project initially, or did you get put on after it got started?

A. I was put on this project this summer, early summer --

Q. This summer, so you didn't --

A. -- so I was not on it initially, no.

Q. Okay, so you didn't have any input about where the wells were to be placed?

A. That's correct.

EXAMINER STOGNER: Mr. Chavez, do yo have any questions?

MR. CHAVEZ: Yes, sir.

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Kolesar, you said sufficient data was acquired. Did you -- By "sufficient", did you do some type of a statistical analysis to give a certain degree of certainty to this, or how did you -- how do you come up with the idea of "sufficient"?

A. I believe that sufficient data was acquired because of the high density of wells that we drilled in those interior four sections approximated 80-acre density. We acquired pressure and logs in those wells, and the pressure range was matched by the model, and the results are fairly consistent with Burlington's numbers.

Q. Okay, is your conclusion about increased density only for the 28-7 Unit, or how do you project your conclusion to go across the entire pool, Basin-Dakota Pool?

A. Okay, the model results that are presented are for the 28-7 Unit.

Q. So you're not trying to draw any conclusions from your testimony about the rest of the Basin-Dakota Pool?

A. In an early slide -- I believe slide 3 under Tab 13 -- I did relate how our model results are consistent with Burlington's and also how our gas-in-place numbers from the model are consistent with Burlington's which would tend to validate some of the broad-brush Basinwide techniques that Burlington is using to screen for infill opportunities.

Q. Okay.

A. Okay?

Q. When you had to adjust pore volumes as Mr. Christiansen said he had to in his model, you also had to adjust permeability; is that right?

A. Yes.

Q. Now, when -- Under Tab 14 where you used reservoir parameters, are the permeabilities you show there the adjusted permeabilities?

A. No, sir, they are not. What those permeabilities represent are the permeabilities that we had from our core data from the 225E well and the match of the zonal pressures in the 225E well. So those permeabilities are the starting point for the Phase II pilot match.

Q. Okay, then I don't understand. You used these actual measured permeabilities for a certain portion of your modeling, but then you made adjustments to them, to fit the results that you had?

A. Okay, the permeabilities shown in that slide represent the match of the zonal pressures in the 225 E well, and that was all the data we had at the time that the 225E model was calibrated.

Then when we expanded the model to include the Phase II wells, we acquired new data, and that is the pressure data from the additional nine wells that we drilled. Somebody had to adjust the pore volume and the permeability in certain layers to honor the pressure data that we measured in those additional nine wells.

Q. And what type of adjustments did you make to the permeabilities?

A. Okay, in some areas where the pressure was lower -- say for example near the 130E well -- it appeared that offset wells were draining that area. So I increased the permeability in that area slightly.

In other areas where the pressure was much higher than the model predicted, then I had to divert flow from existing wells away from that area. So I had to reduce permeability and also reduce intra-block flow.

Q. Overall, then, to come up with the conclusions that you did -- and you agree with the conclusions earlier that there is more gas in place than was originally determined before the pilot project in the 28-7 Unit?

A. I agree with that, yes.

Q. So if you adjust the pore volumes upward and, based on the gas, do you have to adjust, in general, the permeability downward from what you earlier presumed?

A. No, not in general. I had tried in the history match before trying to calibrate the model to the new data that we acquired from the Phase II wells, tried adjusting permeability independently of pore volume, I tried adjusting pore volume independent of permeability, and found that I could only get a good match if I adjusted those together.

Q. Under Tab 15, your last sheet there, you say there are 117 potential 80-acre completions identified. Now, how many -- Is that two more wells for each GPU within the 28-7 Unit, or are there some GPUs from the 28-7 Unit that will not -- that cannot be 80-acre development?

A. Okay, my understanding -- and this number was created by our geologist, and my understanding of that number is that it represents the majority of locations, based on a bunch of considerations like terrain, and also the quality of the Dakota formation. So as you move to the south of the unit, the quality of the Dakota formation deteriorates. So we have areas down there that we probably would not drill at this time. And there might be in certain areas -- the terrain might be too rough to drill four additional wells per section, so maybe we're only limited to three.

But it was his ability to identify as many locations as he could, given those constraints.

Q. Okay, so that doesn't mean that -- There were other constraints besides the reservoir itself that will determine whether or not there will be some infill wells drilled?

A. Yes, that is correct.

Q. All right. Is Burlington a participant in the 28-7 Unit?

A. Yes, they are.

Q. On your economics that you show -- I think it's your exhibit -- here we go, in Exhibit 15 you show a significant difference from the economics that Burlington presented in their Exhibit 8. Did you do any comparisons for those?

A. Could you please explain what you mean by "difference"?

Q. For example, you show a Dakota stand-alone at $650,000 well cost. Burlington's exhibit shows $590,000.

A. Okay, I can't speak to why there's a difference, but I can speak to what the $650,000 represents, and the $650,000 represents the average actual cost -- not AFE cost but actual cost, of four of the Phase II pilot wells. I don't know why it's higher than Burlington's number.

MR. CHAVEZ: Thank you.

EXAMINER STOGNER: Any redirect, Mr. Kellahin?

EXAMINATION

BY MR. KELLAHIN:

Q. Only to ask Mr. Kolesar, does Exhibit 20 contain additional information and data to support your part of the presentation?

A. Yes, sir.

MR. KELLAHIN: All right, sir. That's all the questions I had.

FURTHER EXAMINATION

BY EXAMINER STOGNER:

Q. As far as the abandonment pressures -- and this is Tab 15, third disc -- or page -- are there some actual abandoned wells within the 28-7 unit that reflected these abandonment pressures, or how many abandoned wells are in that unit area?

A. These pressures reflect the average pressure remaining in the interior four sections in the model when the 320s and the 160s are forecast out to their economic limits.

Q. So as far as comparison to any actual abandonments, there are none?

A. There are none.

EXAMINER STOGNER: Any other questions of this witness?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: You may be excused.

THE WITNESS: Thank you.

MR. KELLAHIN: Mr. Stogner, Mr. McCracken is Burlington's reservoir simulator, and he is going to present Exhibits 16 and 17.

<u>CRAIG McCRACKEN</u>,

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

A. Craig McCracken, reservoir engineer, Burlington Resources.

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

A. I have.

Q. And have you qualified before the Division as an expert in reservoir simulation?

A. I have.

Q. What has been your responsibility concerning this case?

A. I prepared the reservoir-modeling section of the presentation for the San Juan 27-and-5 Unit, and I consulted with Mr. Kean on the preparation of the reservoir simulation for the Culpepper area.

MR. KELLAHIN: We tender Mr. McCracken as an expert petroleum engineer.

EXAMINER STOGNER: So qualified.

Q. (By Mr. Kellahin) Let's turn to Exhibit Tab Number 16, Mr. McCracken, and let me have you summarize for us the Culpepper pilot project. Tab 17 is going to deal with the San Juan 27-and-5?

A. That's correct.

Q. Let's do Culpepper-Martin first.

A. Mr. Kellahin, Mr. Examiner, it is my contention that adequate data was obtained in the Culpepper project in the form of pressure and production-rate data to calibrate our Basinwide petrophysical model, thereby increasing the certainty of our simulation model projections.

Unfortunately, however, when we did the economic analysis on the Culpepper wells what we found was that the net present value of these wells was a break-even situation for Burlington.

Q. When we look at the range of opportunities in the pool, this represents the lower range of opportunity in the Dakota?

A. The Culpepper area represented an area that we thought would be prospective but would be at the lower range of what was currently prospective, based on prices that we're currently receiving.

Q. All right, let's go through the modeling then.

A. The Culpepper reservoir model was constructed as a three-layer dual porosity model. And if you think back to the cross-section that we looked at a little bit earlier, the active layers in that area were the Two Wells, the Paguate and the lower Cubero. The Cubero essentially was nonexistent in that area.

We constructed a 47-by-68-by-3-layer grid, which comprised 12 sections and included 42 existing 320- and 160-acre wells. The forecasting was done on the third and the fourth well per GPU over two sections in the center of that area. There were eight existing wells in those two sections, and on the projection side we included eight increased density wells.

The following exhibit shows a picture of what I'm referring to. The blue outline is the 12 sections, and then the green outline, the green-hached area in the middle, is the focus area from which I'll be taking a lot of my projections for increased density wells and recovery factors.

The data that went into our simulation was acquired through some multi-layer testing and some dip-in, which is essentially a shut-in bottomhole pressure data test.

The two multi-layer tests that we did, the two zonal tests that we did where we tried to acquire pressure in each of the three individual zones that comprise this reservoir, one of those tests was successful, one was not. Essentially what happened in the unsuccessful test was, we were not able to isolate the bottom two zones from each other. We felt like we were seeing pressure from both zones at the same time, although we were able to isolate one zone in that second test.

The two shut-in bottomhole pressure tests that we did were on those same two wells, and we felt like that was a validation of the lowest pressure zone. Those shut-in bottomhole pressure tests were done with all three zones open and post-frac.

The pressures that we matched in the simulation, then, came from those tests. And in the Two Wells the range of pressures that we felt like were reasonable for the Two Wells was 990 to 1100 pounds; in the Paguate, 830 to 890; and in the lower Cubero was quite a bit higher at 2300 pounds, indicating that this was quite a bit less permeable zone than the other two zones, and the major production to date in this area had come from the Two Wells and the Paguate.

In the model, one of the things that we attempted to do was to match the pressure. We constrained our model by the operating conditions and tried to match both the pressures and the production rates from the wells. And the bar chart that you see in this next exhibit demonstrates the match that we got.

As I said, we had two pressure points in the Two Wells Reservoir, and what the blue-hached bars represent is those two pressures. The left-hand pressure is from the Davis Number 8R and the right-hand pressure is from the Grenier 11F.

In the Paguate and in the lower Cubero, those two pressures, the left-hand bar in both of those, are from the Grenier 11F -- I'm sorry, from the Davis 8R, excuse me, which was the one well where we were successfully able to isolate zonal pressures.

What the red bar represents is the average of the pressures in the locations of the 80-acre increased density wells that we're drilling.

So what you can see there is that the results of the model were very close to the pressures that we measured. This is illustrative of the quality of the match which gives you a greater degree of confidence in the model that you constructed.

Now, what the next page shows is cumulative production versus time. The actual production from all of the wells in the 12-square-mile area is represented with the solid line. What the red diamonds represent is output from the model. And you can see that through the end of the solid line, that represents a history match. And the closeness of the line with that set of diamonds represents the quality of the model. The closer those diamonds are to that line, the more confidence that you can have that the parameters that you put in the model are the correct parameters.

From that point forward where you just see red diamonds, that represents the projection, that represents what happens with only the existing 320- and 160-acre wells continuing to produce.

So from that point forward, if you look at the point where the solid line ends, that's where the following graph begins in time. And the line between the solid red and the solid blue section represents that same projection, where you're simply allowing those -- and now we're focusing on the area, the two-square-mile focus area within the simulation -- we're simply allowing those wells to continue to produce.

Now, what the red section represents is what happens when you introduce another eight wells into that two-square-mile area. You see an increase of about 1.6 BCF.

However, if you look, then, at the production from those eight existing wells during that same period of time with the eight increased density wells introduced, you'll see a reduction in those wells, and that's due to the fact that production from those wells is being accelerated by the eight 80-acre wells.

So we take all that as a whole and roll it together, what you have is the solid blue section of the curve representing the acceleration portion of the reserves and the solid red part of the curve representing the incremental or new part of the reserves that would not be recovered by additional wells.

Q. And what is that amount?

A. The incremental amount is 1.6 BCF, and the accelerated amount is about .9 BCF. If you flip to the next slide, I show the percentages calculated based on the total production, and it's about 43 percent acceleration and 57 percent incremental. And those numbers are superimposed on a production profile for the 80-acre wells that came out of that two-square-mile focus area.

Projected cumulative production over 30 years from the simulator, which should be equivalent to an expected ultimate recovery, is about 350 MMCF.

Q. Is this an appropriate percentage of incremental recovery to justify increasing the spacing?

A. At current economic conditions, I would say no. There is economic value to acceleration. Acceleration is not valueless from an economic standpoint. However, under the current economic conditions, in an attempt to answer just that question, we prepared the slide that follows this one, that shows that if you have eight existing wells with no additional development, which is represented by the solid blue line on that graph, your net present value over the life of this project is about a million dollars.

If you introduce 80-acre wells under the cost and operating-expense assumptions that are shown under the last bullet, and do eight additional 80-acre tails -- and let me clarify the terminology "tails". It's apparently internal Burlington terminology that we use to refer to adding a Dakota completion onto a Mesaverde that we were already planning on doing. So "tail" implies a Mesaverde-Dakota commingling.

So this would be the Dakota side of a Mesaverde-Dakota commingle, and that's how -- the capital on this slide is considerably lower than what you've seen in the previous exhibit.

What that shows is that the net present value of doing that, of introducing those additional eight wells, is also a million dollars, which is essentially a break-even proposition. These are both net present value calculated at 10-percent discount.

And so currently we don't feel that Culpepper is prospective. That doesn't mean that it never will be. There's a $2.75 NYMEX pricing assumption built into that. At higher pricing it would become more economic. Currently, we feel that $2.75 is a good approximation of the current status of the market, and so at that status it's not something we would pursue.

However, were it to become more economic, were we to get considerably better prices, the potential for this area would be about 48 80-acre locations with incremental reserves of 10 BCF and accelerated reserves of about 7, for a total of about 17 BCF.

Q. Let's talk, Mr. McCracken, about how you regulate a pool that has this range of economic potential. Do you think it's appropriate for the regulators to attempt to carve out part of the Dakota because under current economics it wouldn't support the eight additional wells per section, or should that be an operator decision?

A. I think the danger of that is that it would be a constantly moving target, and I think what these economics demonstrate is that if you raise the price, then you would get a positive NPV. And if you tried to do it based on an economic condition you'd have to pick probably a current economic condition, and then that would cause you to have to revisit that decision constantly.

And it seems more reasonable to me to allow it to be an operator decision because operators make economic decisions on a day-to-day basis. They're not going to pursue something that doesn't make them money, and so it would seem logical to me to allow it to be a case-by-case decision.

Q. So you would support a pool-rule change that was on a poolwide basis, that would cover all these possibilities to let the operator decide what his ultimate density is, so long as it doesn't exceed four wells per GPU?

A. I would.

Q. And in fact, that's what's happened now under the current rules, hasn't it?

A. Indeed.

Q. We currently are allowed two wells per GPU and the operators, based on expectations of recovery and cost, have decided where to develop?

A. That's correct.

Q. And so when we look at the map we can see why the development has occurred?

A. That's right.

Q. Are you comfortable in applying the results on a poolwide basis?

A. Yes, I am.

Q. And why is that so?

A. When I look at some of the exhibits that were presented earlier, what's significant to me is the fact that we can construct relationships between things like infill-to-parent ratios and infill pressures and the amount of new recovery that we could expect to get in those areas. I feel that if those were not interrelated, then you would not be able to extrapolate a relationship to a poolwide situation.

I feel like the fact that they do represent a straight line, when you plot the points that we have, indicates that you would be able to extrapolate it to a pool. The fact that there is a relationship convinces me that you can apply it on a Basinwide basis.

Q. Let's talk about how the adjustments were made in the original gas-in-place mapping. When you forecasted, or when Burlington forecasted the pilot area results, drilled the pilot wells and discovered the reality that the rate and pressure were higher than anticipated, then Mr. Christiansen increased the gas in place in his pore-volume maps, right?

A. Yes.

Q. Did he do that in an appropriate way?

A. I believe so. Anytime a petrophysical model is created, you're dealing with an interpretation of a log in order to determine things like porosity, water saturation, thickness, all the other things that go into how you calculate gas in place. And I think that it's appropriate when you're first constructing that petrophysical model to look at a midpoint range of those values.

And so we constructed our petrophysical model initially that way.

Q. Now, you're honoring the actual pressure data?

A. Yes.

Q. You're changing other values than pressure?

A. Yes. In fact, if you did not go back and revisit your initial assumptions on thickness-porosity-water saturation, based on the fact that your initial models were giving you a pressure that was lower than what you actually saw, then you would, in fact, not be honoring the pressure data that you gathered in the pilot programs.

So the revisiting of the petrophysical model is a way of honoring that pressure data that you got when you did the pilot program.

Q. All right, let's go to the other area and talk about the San Juan 37-and-5, and if you'll start with the first display and continue to the conclusion --

A. Okay.

Q. -- describe for us what you did and what you saw.

A. Again, I feel that we obtained adequate layer pressure and production rate data to calibrate our petrophysical models and increase our certainty in our simulation models. Happily, in the 27-5 unit, we saw considerably different economic results.

The 27-5 reservoir model was a four-layer dual porosity model. Now, if you remember back to Glen's cross-section, we show a very thin Paguate interval, practically, for all practical purposes, nonexistent in this area, well beyond the cutoffs that Glen used in his overlays.

I opted to go ahead and try to build that layer into my simulation, to try to see if it made a difference to take the petrophysical parameters that we did generate for what little Paguate there is there and see if it made any difference in my model. And what I very quickly found out was, whether I had the Paguate on or off I got the same answers, which indicates to me that it's not only not a significant contributor, it's not a contributor at all. So I did build it into the model to test the petrophysics and to test the contribution of the Paguate in the area, but it's a noncontributor.

I built a 51-by-51-by-4-layer grid for this model, which covered 4800 acres and 31 existing wells, and my focus area again will be 1280 acres, although as you'll see on the next slide it's not two sections, it is two square miles, it's not two sections. And on the projection side of the analysis I introduced eight increased density wells into that two-square-mile area.

And so you can see what my area looked like, it's an oriented grid. We feel like we have, particularly in the lower Cubero, which is a major contributor in this area, some information as to the orientation of fractures that I wanted to try to model with directional permeability. So that's why the grid is oriented the way it is.

The data that we had to try to match on the pressure side for the 27-and-5 was four zonal tests, as a result of four zonal pressure tests, we refer to here as multi-layer pressure tests, two of which were successful, two of which were unsuccessful, for the same reasons that I outlined in the Culpepper area. It turned out to be more difficult than we thought it was going to be to isolate one zone from another with the use of bridge plugs in these tests.

We also obtained four shut-in bottomhole pressure tests, one of which coincides with one of our successful multi-layer tests, three of which are unique, three of which are in three other wells that were not zonally tested. There's detail on all this pressure testing data in Exhibit 20.

So the pressures that we wound up matching in the simulation rate, Two Wells pressure of 2623 to 2625 [*sic*]. So the two wells we had zonal pressure on were fairly close in the Two Wells in this area.

In the Cubero there's a little bit more variation, 2429 to 2629.

And in the lower Cubero we had quite a bit of variation, 1948 to 2328. So what I tried to match was the midpoint pressure on all three of those.

What you see on the following bar chart is a similar display to what I showed you in Culpepper where I have the San Juan 27-5 Unit Number 137F pressure in the light blue bar -- and on the screen, it's the left-hand cross-hached blue bar -- and to the right of the red bar in each cluster is the San Juan 27-5 Unit Number 138F.

Going from left to right along my X axis, I have the Two Wells reservoir, the Cubero reservoir and the lower Cubero reservoir.

And what this bar chart is intended to demonstrate is the quality of the pressure match that I was able to obtain.

The next chart shows the quality of the production match that I was able to obtain. Again, this is actual production in the solid red line. This is model production, cumulative versus time, in the red diamonds, and where the solid line ends is where the projection begins.

Again, the closeness of the solid line to the red diamonds demonstrates the quality of the model.

Where that projection begins, then, I did a similar display to what I showed you in Culpepper where I demonstrate that the incremental recovery -- and this is for eight wells on the -- yeah, excuse me, the incremental recovery is about 6.6 BCF over and above what would be recovered by existing wells, and the acceleration piece is roughly 3.3 BCF.

And again I show an individual well project on the next page, which matches up very well with the early time production data that we're seeing on our 80-acre pilot wells in 27-5. The projected 30-year cum is 1.23 BCF and the acceleration is 33 percent and the incremental is 67 percent. And that's on a 30-year look.

Now, the economics for the 27-5 unit, we approached the same way. Our base case net present value is the eight existing wells just continuing to generate revenue as they currently are. That's represented by the blue line. And the cumulative net present value from that case is $3.4 million.

However in this case, when we put eight 80-acre wells into that focus area, we generate an additional $3.4 million of net present value.

So this is something that we would continue to pursue under current economic conditions.

And again, on the third bullet point you can see essentially the same set of assumptions. We've assumed it's a tail, we've assumed $2.75 NYMEX and $400 a month op costs.

Q. Does Exhibit Tab 20 contain the additional supporting documentation that supports your presentation today?

A. It does.

Q. Does Burlington have an estimate of the potential impact in terms of the number of wells to be drilled if the rule is changed. Are we going to see -- what type of number?

A. Within the 27-5 Unit there are probably an additional 120 to 130 locations that could be done. Our current strategic plan calls for approximately 100 80-acre Dakota wells per year on the assumption that we will be able to obtain a change in the current rules.

MR. KELLAHIN: That concludes my examination of Mr. McCracken. We move the introduction of the exhibits behind Tab 16 and 17.

EXAMINER STOGNER: Exhibits 16 and 17 will be admitted into evidence at this time. Thank you, Mr. Kellahin.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. McCracken, were you involved in this project from the initial stage?

A. Yes, I was.

Q. So it was your choice to put the focus area where it was?

A. Yes.

Q. And why did you choose that little area?

A. There are a couple different reasons. That's a very high initial-gas-in-place area, and it's also a very high remaining-gas-in-place area, were two of the main reasons.

Also, the 27-5 Unit in general is an area that is operated by Burlington with high Burlington working and net revenue interests.

EXAMINER STOGNER: Mr. Chavez, do you have any questions?

EXAMINATION

BY MR. CHAVEZ:

Q. Yes, Mr. McCracken, how did you determine the grid size for your model for each of these two models?

A. Typically what I tried to do was, I tried to construct a grid that would have at least three to five cells between well locations. I tested as many as ten very early on, before we ever came before the NMOCD with the pilots, and I tested ten versus five to try to see if there would be a significant difference between those two. There was not. But once I got below five grid cells between wells, I started to see differences in the answers that I was getting.

So I wanted to maximize the number as far as accuracy but minimize it as far as run time on the software.

Q. Okay, and you have different grid size for each model, for the --

A. That's correct. That partially had to do -- and I assume that you're talking about 47 by 68 in Culpepper, 51 by 51 in 27 and 5. The acreages of those two areas are slightly different. The 27-5 is about eight square miles, and the Culpepper is about twelve. So that's part of it. The individual grid blocks are much closer in size than the overall area.

Q. In your economic model, the last one we looked at --

A. For 27-and-5?

Q. Yes, for 27-and-5, did you use the same assumption that had been made earlier by Burlington for a Dakota stand-alone well as far as the capital cost and --

A. When you say earlier, are you talking about the -- I believe it was Exhibit 5 or --

Q. Eight.

A. Eight? Those economics were done with stand-alone costs, and the economics on the 27-and-5 were done as a tail on a Mesaverde-Dakota commingle. And also they were done incrementally. In other words, we assumed that the Mesaverde well would be drilled in this case and that the costs that were used against the Dakota were the costs incremental to drilling a stand-alone Mesaverde well.

MR. CHAVEZ: Okay, thanks.

EXAMINER STOGNER: Any redirect?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Any questions of this witness?

MR. BROOKS: No.

EXAMINER STOGNER: You may be excused.

You have one more witness, right?

MR. KELLAHIN: Yes, sir, we're down to talking about the notice we provided and the discussion on what to do with the well-location requirements in the federal exploratory unit.

EXAMINER STOGNER: Okay, I'm going to call a five minute recess at this time --

MR. KELLAHIN: All right, sir.

EXAMINER STOGNER: -- five to ten.

(Thereupon, a recess was taken at 4:46 p.m.)

(The following proceedings had at 5:05 p.m.)

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: Mr. Stogner, thank you.

MATT GRAY,

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

A. Matt Gray, I'm a petroleum landman for Burlington Resources.

Q. And where do you reside, sir?

A. Farmington, New Mexico.

Q. On prior occasions have you testified before the Division as a petroleum landman?

A. No, I have not.

Q. Summarize for us your education and work experience.

A. I graduated from the University of Oklahoma in May of 2000 with a petroleum land management degree. Previous to that I worked three internships, one for Devon Energy, one for Conoco, and one for Nichols Land Services doing various land work for those three companies, and that was a total of approximately three years of experience. I've been with Burlington for about one and a half years now.

Q. As part of your responsibilities to Burlington as a petroleum landman, have you made yourself knowledgeable about the federal exploratory units in the San Juan Basin?

A. Yes, I have.

Q. And you understand that those are divided units that use a concept called participating areas in the expansion of those areas to include, in this instance, Dakota wells?

A. Yes, I do.

Q. Are you familiar with that concept? In addition, have you had discussions with the Aztec Office of the Oil Conservation Division concerning various possible requirements concerning notification to various interest owners within the federal units?

A. Yes, we have.

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

EXAMINER STOGNER: Mr. Gray is so qualified.

Q. (By Mr. Kellahin) Let's deal with the notice issue first, Mr. Gray. If you'll turn to the exhibit book and look behind Exhibit Tab 1, there's a copy of a letter I've signed as a notice letter, followed by an Application. Did Burlington mail that Application and notice letter to all operators in the Basin-Dakota Pool?

A. Yes, we did.

Q. And did you do that more than 20 days before the hearing today?

A. Yes, we did.

Q. How did you develop the list of operators for the Basin-Dakota Pool?

A. We got that from the Aztec NMOCD office.

Q. In addition, did you double-check your database to confirm that the OCD district office list was accurate and correct as best possible?

A. Yes, we did.

Q. And did you cause this notice and Application to be sent certified mail, return receipt?

A. Yes.

Q. When we look behind Exhibit Tab Number 1, do you have copies of the green cards that were returned?

A. Yes, we do.

Q. All right. To the best of your knowledge, Mr. Gray, have you complied with the Division requirements concerning notification for this hearing?

A. Yes.

Q. Let's turn to Exhibit Tab 18. What have you included in the exhibit book behind Exhibit Tab 18?

A. What we have behind Exhibit 18 is a timeline showing what has happened historically in the Basin-Dakota Pool and what has happened in the last several years regarding increased density.

Q. All right, and without reading the specific details, give us a general summary of what's occurred.

A. Okay. Prior to 1999, there were various Dakota spacing orders. The Basin-Dakota Pool was established in 1960, and that had 320-acre spacing. In 1979 the 160-acre increased density order was issued.

In February of 1999, as you know, we had an order issued to allow for 80-acre Mesaverde increased density. And between the time of 1999 and 2000, we received three separate orders for 80-acre pilot projects from the NMOCD, Conoco doing one of those and Burlington having two of those.

After Burlington and Conoco felt like we had sufficient information, we held numerous meetings with different entities. In July of 2001 we had a Dakota operators' meeting. In that meeting we had a very positive feedback, had no objections from any of the operators and actually had numerous letters of support from a number of the operators, which are found behind Exhibit 19.

One of the things that came out in the operators' meeting was that they wanted the Mesaverde and Dakota orders to match up one way or the other.

After that we had numerous meetings, one with the BLM to discuss our plans, a couple of meetings with the NMOCD's Aztec Office, and we also held a public meeting that was hosted by the Aztec Office of the NMOCD.

Q. Behind the time line is the various notices for the meetings attendance rosters, sign-up sheets for the meetings as described in those notices?

A. Yes.

Q. All right. And then in Exhibit 19 is the BLM Farmington letter that was referred to earlier this afternoon, followed by other letters of support from operators in the pool?

A. Yes.

Q. All right. Let's turn now to the subject of what to do concerning notification within the federal exploratory units. If you'll turn behind Exhibit Tab Number 3, just so we're clear on what we're doing, let's identify this first display. What are we seeing?

A. This is the footage setbacks for the Basin-Dakota and the Blanco-Mesaverde, Basin-Dakota on the left and Blanco-Mesaverde on the right.

Q. This deals with only the 660 portion of the rule and doesn't address the fact that these internal lines have a 10-foot setback?

A. Correct, that's -- Yes.

Q. All right. Let's forget the 10-foot line, it's not really an issue. Let's talk about the 660 line.

A. Okay, this is on drillblocks only, not on federal units. What we have currently in the Basin-Dakota Pool, we have a rule that states that a well cannot be placed any closer than 660 feet from the quarter-section line. In the Mesaverde Pool we have the rule that states the well cannot be placed any closer than 660 feet from the proration unit.

Q. Burlington and Conoco are proposing to make the Basin-Dakota 660 line outside of the federal units consistent with the Blanco-Mesaverde 660 line?

A. Yes.

Q. And that has the unanimous support of the operators in the Basin?

A. Yes, as far as I know.

Q. All right. Turn past that and let's talk about what to do in the federal unit. Let's take this as a hypothetical federal unit. Around the unit boundary you've got a black line, correct?

A. Correct.

Q. There is a hashed line just inside that outer boundary?

A. Uh-huh.

Q. What does that represent, Mr. Gray?

A. That represents a 660-foot setback around the entire unit boundary.

Q. Okay. You support, or Burlington and Conoco support maintaining that as a setback?

A. Yes, we do.

Q. Let's deal with, then, identifying and describing the options on four possible interior situations. If you'll look at the display, let's deal with that block that is the west half of Section 25. It's on the right-hand side of the display. It's a stand-up 320, and it's identified as a non-committed tract. What does that mean?

A. That means that the working interest owners in that tract, or the royalty owners, have not committed their lands to the exploratory unit.

Q. All right. So if a well is drilled by any of the working interest owners in that noncommitted -- in that drillblock with noncommitted tracts?

A. Yes, it would be treated like a drillblock interest rather than a unit interest.

Q. This is a situation where the 320 is 100-percent noncommitted?

A. Correct.

Q. What is the proposal that Burlington and Conoco are requesting in terms of well locations adjacent to one of those type of drill blocks?

A. We request that we put a 660-foot buffer zone around the noncommitted tract and treat the interior of the noncommitted tract like a drillblock spacing unit.

Q. All right, so the checkered line that is on the unit side, which is the outside of the noncommitted tract, has a standard 660 setback?

A. Yes.

Q. And if you want to be closer, then you're going to have to notify all the appropriate owners in the noncommitted tract?

A. Correct.

Q. What happens if the owners in the noncommitted tract want to be closer than 660 to the boundary of their spacing unit? What happens?

A. They have to likewise notify the participating area or the owners that are outside of their noncommitted tract.

Q. All right, we're going to treat that the same way as we treat the outer boundary, then, of the unit?

A. Yes.

Q. Is there any difference of opinion, as you understand it, between the Oil Conservation Division in Aztec and Burlington and Conoco about that requirement?

A. Not as I understand it, no.

Q. All right, let's deal with the next situation. If you move just to the left and look at the east half of 26, you now have what is identified in blue is a partially committed interest. What does that mean?

A. That means that the entire spacing unit was not left out of the unit, but some individual owners within that spacing unit did not want to ratify the unit agreement.

Q. When I look at the unit map we're looking at, there's a diagonal line that runs northeast to southwest, this diagonal grid?

A. Uh-huh.

Q. What does that represent?

A. Around the noncommitted tract or --

Q. Well, throughout the whole unit, what is that?

A. Oh, that represents the participating area.

Q. All right. So Section 26 is in the participating area, except the west half of 26 has a portion of it that is not committed to the unit?

A. Correct.

Q. What happens under that situation?

A. Under that situation the owners who are in that partially committed interest take their interest on a drillblock basis. That is, they get their interest on just that 320 acres where that well is drilled. Those PA owners who are in that drillblock take their interest on a participating-area basis.

Q. For the noncommitted tract and the partially committed tract, is there any contractual solution in the unit agreement or the unit operating agreement that protects correlative rights to the extent that notice should not be required for these type of situations?

A. For these type of situations, because there are parties who have not ratified the unit agreement, they're therefore not subject to the unit agreement, and therefore the contractual obligations of the operator do not apply to them. So the answer is no.

Q. They're not going to be protected?

A. Correct.

Q. So you would recommend that the partially committed tracts receive notice?

A. Yes.

Q. If the well to be drilled by the unit operator is closer to that tract than 660 feet?

A. I would actually put the buffer around the entire spacing unit.

Q. On both sides of the line. Do you see what I'm asking you? Let me do it again.

A. Okay.

Q. When you look at the blue rectangle --

A. Uh-huh.

Q. -- the 660 setback, is that on both sides of the line, or is it just internal setback for the partially committed spacing unit?

A. Okay, we would like to -- There's a 660-foot setback on the exterior of the partially committed drillblock. Now, on the interior, because there's participating area interest owners within that interior, we feel like it would be advantageous to be able to put a well 10 feet from that line and that the correlative rights would not be affected by that that well because that well would be participating with those participating area owners in that portion of the drillblock.

Q. All right. So should the shaded area that represents the 660 setback in the west half of 26, should that be on the outside of that 320 or on the inside?

A. That should be on the outside of that 320.

Q. All right, so we need to reverse that?

A. Well, it does appear that it's on the outside. It doesn't really look like it's kind of playing tricks with your mind.

Q. All right, it's an optical illusion for me, but the intent is that that 660 setback is on the outside --

A. Right --

Q. -- of the 320?

A. -- correct, yes.

Q. All right. Again, no contractual solution for that situation?

A. No.

Q. Let's deal with the other two possible situations. Let's go to the south half of Section 22 and look at what is labeled "Drill Block A". Describe for us what you're trying to represent by that example.

A. Okay, this is a drillblock in which there was a well drilled that was deemed noncommercial, and therefore that well and drillblock were not brought into the participating area.

Q. There is a procedure in the agreement for an expansion of the participating area, right?

A. Correct, if that well was deemed commercial, then that participating area would expand to include that drillblock.

Q. And who makes that decision ultimately?

A. The commerciality is figured by the BLM.

Q. All right, the operator submits the data and the BLM makes the final decision about whether the PA is expanded, based on this commerciality concept, right?

A. Yes, correct.

Q. The assumption here is that the well in the south half of 22 is drilled and it's deemed noncommercial --

A. Yes.

Q. -- right? Should there be any further notice requirements in the drillblock if I want to be outside the drillblock but closer than 660?

A. There should not be any notice requirements beyond the notice requirements that are called for in the actual unit agreement and in the unit operating agreement.

Q. All right. Let's talk about how their correlative rights are protected.

A. Okay.

Q. You're suggesting that the Division need not require notice for a well that's closer than 660 to that Drill Block A because there's additional provisions within the contractual scheme that provides them that opportunity?

A. Yes.

Q. Describe for us how that works.

A. Each year the operator of a unit is required to submit a plan of development to all the working interest owners, as well as the regulatory agencies. Those plans of development show the interest owners where we plan on drilling wells in the upcoming year. And as an interest owner, you can look at that plan of development and monitor the production -- or the development plan that the operator has laid out.

As far as notification purposes, we feel that that supplies efficient notice -- or sufficient notice, to the working interest owners, because if they see that there's a well proposed in a drillblock offsetting their nonparticipating drillblock they have the opportunity to contact the operator and discuss the setbacks with them and come to an adequate solution to that problem.

Q. All right, let me follow through with that point. Annually they will receive an indication of future development, they can look at that list, see if there is a well to be offsetting their Drill Block A and there is an opportunity and a time period when they can register an objection, right?

A. Yes, they can notify the operator and discuss it with them.

Q. What if they're not satisfied with the operator's solution? Do they have any relief before the BLM on the

BLM's approval of the plan of development?

A. They are required -- or they have the opportunity to address the operator, and that's where their avenue of --

Q. Recourse?

A. That's where their avenue of relief comes, their avenue of recourse is to contact the operator or contact all the other working interest owners within that unit.

Q. All right. My question, though, is, if they're not satisfied with that solution, what do they have? Do they have a contractual remedy where they can seek judicial relief or any other recourse in that situation?

A. There is the contractual remedy that they have the opportunity to object to it, and therefore it goes -- essentially would go to a vote within the unit as to where that setback should be.

There's another contractual remedy in that if a well is drilled abutting that Drill Block A and that working interest owner in Drill Block A feels like they're going to be drained, they have the opportunity to propose a well to offset that draining well and to therefore protect their gas in that manner.

Q. All right. So if they can't work out a solution with the operator, they lose on a majority vote, the well gets drilled that's closer than 660 to the Drill Block A, there is a contractual solution insofar as they can propose the offset protection well --

A. Yes.

Q. -- and require that that be drilled?

A. Yes.

Q. All right. Your recommendation, then, is not to provide additional notification through the Division rules if there is an encroaching well closer than 660 to drillblock A?

A. Correct. And I might add that if they do drill an offset protection well and that well is deemed commercial, then your problems go away because that drillblock is brought into the participating area.

Q. All right. So let's talk about whether we can fix the -- specifically the opportunity to object, or is this a dynamic situation that continues to move and reoccur as the PA is expanded?

A. If I heard your question correctly, if there is a 660-foot setback around this Drill Block A and --

Q. Well, let me pose it to you, let me give you a fact situation.

A. Okay.

Q. Let's assume we're now required to give notice through the Division process to the interest owners in Drill Block A because we're going to be closer than 660 --

A. Uh-huh.

Q. -- which is not the solution you want, but it's been discussed?

A. Correct.

Q. All right. I go to hearing and I can't get that location approved, yet it may be the best location to drill. I'm stuck with that location.

A. Uh-huh.

Q. If the owners in Drill Block A decide they want to drill 10 feet off the line and do so successfully and it's a commercial well, the PA gets expanded --

A. Correct.

Q. -- right?

A. Correct.

Q. If they're also required to stay 660 off the line, drill the well, the PA gets expanded?

A. Correct.

Q. So your point is?

A. My point is that you lose that opportunity to put the well in its optimal location.

Q. Because of the ability to expand the unit and protect correlative rights?

A. Correct.

Q. And that expansion is going to continue as wells are deemed commercial?

A. It's definitely a moving target. As you drill more wells, more acreage is brought into the participating area, and so it's definitely a constantly moving target.

Q. All right, you and the District Office, then, have a difference of opinion about the notice requirement in this situation; is that not true?

A. I believe we do, yes.

Q. All right, let's go to the last situation and talk about Drill Block B. What are you trying to illustrate here?

A. This is a proposed well in a drillblock that has never been drilled. Therefore it's not in the PA, because it's never had any production on it.

Q. All right, let's assume the Drill Block B owners -- it's a totally committed tract but it doesn't have a well and the PA has not been expanded, right?

A. Correct.

Q. What if that proposed well for Drill Block B is closer than 660? Is that a problem? Should they be notifying the same interest owners? I guess, right?

A. No, we feel that, first of all, if that well is deemed commercial -- and as you know, the majority of the wells we drill will be deemed commercial -- then that drillblock will come into the participating area. And therefore there would not be any correlative-rights issues in that instance.

We also have the off chance that that well is deemed noncommercial, and in that case we feel that if it's a noncommercial well and if it's abutting a participating area, that the production from that noncommercial well will be small enough and not sufficient enough to cause a great amount of drainage in the participating area, especially considering that the participating area is taking production from all these other spacing units and therefore has a much larger amount of gas.

Q. So you're suggesting that in Drill Block B, if Drill Block B owners want to be closer than 660 to the outer boundaries of the south half of Section 28, they shouldn't have to notify the other interest owners in the unit about that encroachment?

A. Correct, because you would get into the same situation and put the well in the less optimal spot if you had to.

Q. Tell me about the notice. Are the owners in the south half of 28 going to be the same people that are going to get notice? Are they going to send notice to themselves? Who are the owners in the PA?

A. The PA owners are people who have production on their land.

Q. So it's possible that there could be a difference in percentage or identity of parties between Drill Block B and the participating area?

A. Yes, and it's likely that that would be the case.

Q. All right. But you're suggesting there's an expansion process in the unit agreements that protects correlative rights in this situation?

A. Correct.

Q. What about the reverse? What about if there is a well in Section 27, 33 or 34 that encroaches on Drill Block B closer than 660? Should notice be sent to Drill Block B owners?

A. No, we don't believe so.

Q. Okay, and why not?

A. Because like in Drill Block A, the owners in Drill Block B have that opportunity to propose an offset well, in which case they would protect their correlative rights in that way, and when that offset well is drilled it would be brought into the PA and therefore the correlative-rights issue would be gone.

Q. So if they have a well offsetting them closer than 660 they can observe the results of the well. If it's noncommercial, they can decide if they want to compete against noncommercial wells, right?

A. Uh-huh.

Q. If it's commercial they can decide if they want a competing protection well, correct?

A. Correct.

Q. And if the competing protection well is economic, the PA gets expanded?

A. Correct.

Q. And they now participate on their PA percentage basis in that area?

A. Yes.

Q. Okay. You're suggesting, then, that no notification be required in that situation?

A. Yes.

Q. And you and Mr. Chavez, I think, have a difference of opinion, do you?

A. I believe so.

Q. All right. Have you provided a written summary of what you and I have just described behind this plat?

A. Yes, I have.

Q. You've reduced this to writing so that Mr. Chavez and Mr. Stogner can look at the concept?

A. Yes.

Q. Summarize for us, Mr. Gray, what you're recommending concerning the notifications in the exploratory units.

A. We recommend that we put a 660 buffer zone around the entire unit, a 660 buffer zone around any noncommitted tracts and any partially committed drill blocks. We recommend that we leave it up to the operator to decide where to place a well within -- in and around Drill Block A and Drill Block B and don't have that 660-foot buffer zone.

Q. Do you believe there's adequate protection within the agreements to protect correlative rights in the circumstances you've described?

A. Yes, I do.

MR. KELLAHIN: That concludes my examination of Mr. Gray, Mr. Stogner.

We would move the introduction of Exhibit 18, 19, 1, 2 and 3.

EXAMINER STOGNER: Exhibits 18 and 19, 1, 2 and 3 will be admitted into evidence at this time.

MR. KELLAHIN: And so I don't forget, I think 20 is the last one that I've not asked you to admit, and I would ask that you do so now.

EXAMINER STOGNER: We did reference that several times --

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: -- so Exhibit Number 20 or Tab 20 will be admitted into evidence. Does that cover all Tabs 1 through 20 that you know of?

MR. KELLAHIN: I believe it does, sir.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Mr. Chavez, I'll let you start out with the questioning on this one.

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Gray, considering the wording of the proposed footage location rule, should not there be a buffer also within the noncommitted and partially committed tracts?

A. What we have proposed in the noncommitted tracts, we expect those to be treated like a drillblock would be treated, therefore the buffer would be there. We've just expected that that would be treated as a regular drillblock that we're asking for. So therefore it's not displayed on here.

And as for the partially committed tracts, like I said earlier, the buffer is not on the interior because you have participating area owners within that partially committed area, and it would be unfair to not allow that well to be placed in an optimal location when that -- because those participating areas are in that partially committed acreage.

Q. So within the boundary of the federal unit, any partially committed tract would be allowed to have a well within 10 feet of the outer boundary of that tract, but a noncommitted tract would be limited to 660; is that what you're saying?

A. Yes, sir.

Q. Does the wording, the proposed, state as much?

A. The current wording in our Application, I believe also assumed that in the noncommitted tract it would be treated as a drillblock tract, drillblock spacing unit, and therefore would have the drillblock rules that we have proposed.

As far as the partially committed interest, yes, we have left out -- we have not placed a buffer around the interior of that partially committed interest in the wording of our Application.

Q. In Drill Block A in that particular example, there's a nonparticipating well. Is participation based on a well basis or on a GPU basis under the unit agreement?

A. Participation -- to be brought into the participating area, it's based on a producing well, a commercially producing well basis.

Q. So if a commercially producing well were drilled in the southeast corner of -- southeast quarter of Section 22, would that entire block come in, even though there was a previous well that wasn't participating? And then would both wells be participating, even though one was initially not --

A. No.

Q. Only the new well?

A. The new well would come in, as well as everything, other than a 40-acre tract around the nonparticipating well.

Q. So you would have the 40 acres around the nonparticipating well still nonparticipating, and consequently there would be -- interests within the tract would not be equal throughout the tract; is that correct?

A. That is correct. The fact that that 40 acres is nonparticipating really excludes the owners -- Well, how am I trying to say this?

The 40 acres around that nonparticipating area would be left out of the participating area. That's --

Q. Is that consonant with your understanding of the spacing regulations of the Oil Conservation Division for the dedicated acreage and participation under the rules and regulations of the State of New Mexico, that you can leave 40 acres with a different interest, other than the other acreage in the tract?

A. That's the way it has been done in all the federal unit agreements that I've read.

Q. A well that is drilled within 10 feet of the boundaries of the tract that it's on, would you say that it is taking a large percentage of its gas, maybe up to close to half the gas, from the adjoining tract?

A. I definitely could not give a percentage because that's not my expertise, but I'm sure that there is some drainage occurring, yes.

Q. Does part of your studies for being a landman include issues surrounding drainage and well locations?

A. No.

Q. You mentioned that the BLM determines the commerciality of a well. Is that for any well on a tract, whether it's state, fee or federal or Indian land that's involved?

A. Yes.

Q. The opportunity to drill an offset well to the well that is 10 foot from the tract line -- that opportunity might require the operator who feels that they're being drained to drill another well 10 foot from the line. Are you familiar with the issues and definitions of waste as they've been traditionally used in conservation?

A. Somewhat, yes.

Q. Do you understand that drilling an unnecessary well may be considered wasteful?

A. I don't know that drilling -- that if an offset well is being drilled to offset another well would be considered wasteful, in that we are asking for the operator of the unit to be able to use their discretion and the working interest owners to use their discretion as to where to place that well. And if that well is brought into the PA, then that is what will cure the problem, cure the correlative-rights problem.

And I don't think that the operator or the working interest owners would be interested in placing the well in an area that would cause waste.

Q. You stated that if a well was -- or a tract was not brought into participation because a well was a low-productivity well, that the small amount of gas produced from that well would not cause a violation of correlative rights. Did I understand that correctly?

A. Well, I stated that it would cause a correlative rights issue. There possibly and probably would be some drainage.

But what I stated is that if it is placed abutting the participating area, the amount of drainage that a noncommercial well would cause would be so insignificant that the opportunity to place a well in the optimal position far outweighs that small amount of drainage on the participating area.

Q. When you say small amount of gas, at what point did you draw the line that there is -- that the drainage would be significant?

A. I definitely can't draw a line in the sand. I would estimate -- I hesitate to estimate, even.

But if you look at this example, for instance, you have about 10 wells or 10 sections that are in the participating area with producing wells, compared to one well that's not in the participating area and that would possibly cause a minor amount of drainage because it's a noncommercial well. That percentage would be very small, so I can't draw an exact line in the sand.

Q. If an operator determines that the correlative rights may be violated, say if they're in a nonparticipating tract, if they feel the correlative rights might be violated by wells being drilled within 10 feet of the nonparticipating tract, is their only recourse -- are they limited by the unit agreement to use only the unit, or can they still come the Oil Conservation Division to try to protect their correlative rights?

A. As far as I know, their recourse is to contact the operator and deal with the operator under the unit agreement. And I'm not aware of anything that allows them to come to the Oil Conservation Division and protest that.

Q. Would you be opposed to an operator having that prerogative, to come to the Oil Conservation Division anytime that they feel their rights are being violated?

A. I hesitate to answer that question because I don't know, but it -- Let me think.

Are you talking about if the working interest owner contacts the operator and there is not agreement or no solution in sight and in that instance has the opportunity to come to the OCD and discuss it with the OCD and have the OCD be somewhat of a mediator between the two? Is that --

Q. No, my idea was -- the issue was, does your knowledge of the operating agreement limit the operator to only the recourses within that operating agreement if they feel they're being infringed upon by a well that's too close to the nonparticipating tract?

A. I don't think it limits it to that. But there's not any wording in there that provides for that. I don't think that it limits it, but there's nothing that provides for it.

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

MR. BROOKS: Could I ask some questions on this?

EXAMINER STOGNER: Why don't you go ahead and --

MR. BROOKS: I'll try to be fairly brief since it's so late in the afternoon.

EXAMINATION

BY MR. BROOKS:

Q. The proposal that you are suggesting, as I understand it, that the Applicants have asked for in this case, would allow a well to be drilled anywhere in a federal participating area, subject to this 10-foot provision which is -- I think everybody agrees it's not significant one way or the other -- the -- for a well to be drilled anywhere in a federal participating area except in the location which is within 660 feet of the outer perimeter boundary of the federal participating area, or within 660 feet of a spacing unit which either is uncommitted or includes an uncommitted tract; is that correct?

A. Not a participating area but a 660-foot buffer around the unit area.

Q. I'm sorry, I misspoke. Around the outer perimeter of the federal exploratory unit?

A. Yes.

Q. So that it would permit a well to be located within 10 feet of the line that divides a participating area from a nonparticipating tract, correct?

A. Yes, sir.

Q. Now, the owners of the nonparticipating tract would share in the production -- the owners of the nonparticipating tract, if they owned only in the nonparticipating tract, would not share in the production of that well that was 10 feet from their line at all, would they, unless a well were subsequently drilled on that line?

A. No, sir, they would not, but that's why we've had that 660-foot buffer around that, for a nonparticipating tract -- Oh, I'm sorry, I was looking at a noncommitted --

Q. The owners of --

A. -- tract. Okay.

Q. I'm sorry, a nonparticipating --

A. Right, I misunderstood.

Q. -- we're not talking about a noncommitted tract.

A. Uh-huh. No, they would not share in that production.

Q. Unless a well was subsequently drilled on their tract?

A. Correct.

Q. Okay, if I may get up here. If the quality of the formation -- and the technical people, I'll have to apologize because I'm using nontechnical language because I'm not a petroleum engineer.

But if the quality of the formation was deteriorating as you move this direction, toward Drill Block A over here which is nonparticipating, it might well be unlikely that Drill Block A would be fully developed, but there might be some play in here, and it might be small or it might be considerable in where the technically optimal location would be, whether it be over here on Drill Block A or whether it be here in the participating area; is that not a possibility?

A. Yes, sir.

Q. And let us suppose that Drill Block A was subject to an overriding royalty interest of 12.5 percent so it -- 75-percent net revenue interest to the working interest owner, correct?

A. Correct.

Q. And Drill Block -- and this adjacent drillblock here, which is not vacant but it's in the existing participating area, had a 5-percent overriding royalty interest on it. So it would be what, 82.5-percent net revenue interest and working interest? Make that assumption.

A. Yes.

Q. Okay. Now we're talking about optimal. Would not that make this location 10 feet from the property line look a whole lot better to -- and I understand Burlington wouldn't do this, we're talking about some hypothetical operator -- would not this location over here with the 82.5-percent net revenue interest look a whole lot more optimal to a lot of operators than the one over here which brought in this 75-percent net revenue interest and would allow that overriding royalty interest owner to come in and dilute the net revenue interest in the PA?

A. That is a situation -- I don't know that our engineers who picked those locations would make that decision --

Q. Well, I told you we weren't talking about Burlington.

A. Correct.

Q. But we're talking about a rule that's going to be established forever by us, correct? It's going to --

A. Correct.

Q. -- nationwide?

A. Yes.

Q. Okay. Now, we're talking about what people can do about something, and Mr. Kellahin has referred frequently to notification. Well it's not really just an issue of notification, is it, because if the OCD rules don't permit you to drill a well in a certain place, then -- under the normal rules, then, you have to come to the OCD if you want to drill in that location and get an order permitting you to drill at an unorthodox location, correct?

A. Yes.

Q. So it's not just a question of notification, it's a question of what you can and can't do, of whether you have to have permission of the OCD to do it or not?

A. Correct.

MR. BROOKS: Okay. I could ask a number of more questions on this, but I think I've asked sufficient questions for this late in the afternoon, so I'll let Mr. Stogner have a crack at you.

EXAMINATION

BY EXAMINER STOGNER:

Q. Okay, one -- I want to -- a couple of things pursuant to Block A and Block B.

In this particular instance I'm going to refer back to your exhibit.

The northern boundary line, now, am I to assume in both examples, in Sections 20 and 22, that you're assuming that all the interests are the same in those two particular sections?

Because when you want a buffer zone that would be on both sides of that particular half-section line you're going to have, assuming -- or considering the fact if there are different royalty interests, overrides and such as that?

A. Are you talking about in Drill Block A and B?

Q. Yes.

A. Well, those two situations can be illustrated by Drill Block A and B and the fact that they are within the unit, those -- they're -- the north half of Section 28, I believe, and the north half of Section 22 are within the unit and therefore have the same contractual remedies that Drill Block A and B would have, that we've discussed.

MR. CHAVEZ: I have another question.

EXAMINER STOGNER: Sure, Mr. Chavez?

FURTHER EXAMINATION

BY MR. CHAVEZ:

Q. Under your proposed spacing requirements, what would be the spacing between a well drilled in the boundary between the south half of Section 15 and the south half of Section 22, which are both --

A. Those are both illustrated by the Drill Block B scenario in which there has not yet been a well drilled. Are you talking about a setback between wells or a setback between --

Q. Setback between the boundary of the south half of Section 15 and the north half of Section 22, which both are nonparticipating?

A. Yeah, those are both undrilled drillblocks, and they would be considered the same as in drillblock B, and it would be the same remedies and the same ability --

Q. The 10-foot limitation --

A. Yes, yes.

MR. CHAVEZ: Okay.

FURTHER EXAMINATION

BY MR. BROOKS:

Q. In to my hypothetical about an overriding royalty interest owner, is it not also not unusual to encounter fee tracts in federal participating areas?

A. That does happen.

Q. And are they not often very small fee tracts?

A. Possibly could be, yes.

Q. And is it not fairly common in northern New Mexico to have provisions in oil and gas leases to the effect that the lessee can commit a fee tract to a federal exploratory unit?

A. Yes.

Q. Okay, so the remedies, contractual remedies you were talking about, would apply only to working interest owners in the unit; is that not correct?

A. That is correct, but I might just refer to the Division's stance on notification and notices for a hearing such as this, and that we notify the operators. The operators therefore look out for the best interests of the working interest owners, who therefore look out for the best interests of the override and royalty owners.

Q. Doesn't the Division have some responsibility to look out for those people too, though?

A. In an instance -- as for notification, such as in this purpose, I think that what's good for the working interest owner is good for the overriding royalty owners.

MR. BROOKS: Okay, what's good for General Electric is good for the USA. Thank you.

EXAMINER STOGNER: Anything else, Mr. Kellahin, any redirect?

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Just one small point, let me see if I remember this right.

Am I correct in remembering that in the unit agreements there is a provision for expanding a PA by geologic inference to include a prospective Dakota drillblock that's being encroached upon, without having to drill another Dakota well on that drillblock?

A. That is correct, and in all cases, in all of our federal units and all the ones that I know of, that is a provision provided for in everything below the base of the Mesaverde, so -- which would include the Dakota.

Q. All right, so if we look at Mr. Brooks' example where you're encroaching on one of these drillblocks ten feet off the line, their remedy is to petition on a geologic inference because they're making a contribution to that wellbore and therefore can have the PA expanded, share in the production of that well, and not have to drill their own well?

A. That's a very good point, yes.

Q. And in the alternative, if they choose in Drill Block B to be closer than 660, we're not suggesting that they should go through an additional notice and Division hearing process, because if that well is deemed commercial, the interest owners in the PA can protect themselves by having the PA expanded to include the well?

A. That is correct.

Q. So there are better contractual solutions than the Division can provide with their regulatory remedy?

A. Yes, I believe so.

MR. KELLAHIN: All right, sir, no further questions.

FURTHER EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Gray, you said something that I need to expound upon. Would you repeat what you said about notification to only the operators in an unorthodox location?

A. No, I was referring to a case such as this. I was not referring to an unorthodox location; I was referring to an instance where there is notification in a case such as this where we notify the operators of the pool.

I wasn't referring to an unorthodox-location notification.

Q. Oh, okay. You're -- Okay, so what you stated was not to be construed as only operator?

A. Correct, yes, I was not talking about an unorthodox location notification.

Q. Okay.

A. And that can be seen in a unit agreement. The working interest owners are typically notified in a case such as this, an increased density case, and therefore they have the obligation to look out for their royalty and override owners.

FURTHER EXAMINATION

BY MR. CHAVEZ:

Q. Can I ask you just to -- if this is an example of something you testified to earlier? Under Tab 17, would be the third sheet, title at the top, "Simulation Area, San Juan 27-5 Unit" --

A. Yes.

Q. -- and in Section 3 you're in the unit boundary, and the southeast of the southwest quarter is -- according to the legend below that, that's an example of a 40-acre area where a well, even though in a dedicated 320-acre tract, is not participating in the same proportion as -- in the production from that 320, as the other well or wells that may be in the same tract. Is that an example?

A. The proportion of the drillblock is eliminated around the 40-acre tract, you're correct, yes.

MR. KELLAHIN: May I follow up on that question, Mr. Stogner?

EXAMINER STOGNER: Please, Mr. Kellahin.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. If the 40-acre tract has got a noncommercial well, what are we protecting if they have nothing at risk?

A. A noncommercial well, I mean --

Q. Why should we provide notification, opportunity to object and a hearing for an interest owner who has condemned his own acreage with a noncommercial well? Can you see any reason?

A. No, not that I can think of.

MR. KELLAHIN: I can't either.

FURTHER EXAMINATION

BY EXAMINER STOGNER:

Q. If a commercial well is put in a participating area, does it remain there as long as its life of production?

A. It remains there for the life of production of all wells within the participating area.

Q. So once -- A participating area is not delineated, is what you're saying?

A. Does not contract, it expands.

Q. Well, let's talk about this scenario with the 40 acres. Why does that exist?

A. For some reason or other another well was drilled and deemed noncommercial and did not have good -- adequate production to be deemed commercial.

Q. Either poor reservoir quality or how about poor completion techniques by the operator?

A. It could be any one of the two.

Q. There again, Burlington wouldn't knowingly complete a well badly, but there again it applies throughout the pool, does it not?

A. And if the well is completed badly and there's a redrill, that still leaves that 40 acres out. It does not -- unless -- Well, I won't get into that, that's a -- It would be convoluted.

FURTHER EXAMINATION

BY MR. CHAVEZ:

Q. But outside out of the unit -- if that well were outside of this unit, it would be participating with every other well in the same 320 tract; isn't that correct? It's only because it's within a unit that it's contracted to 40; is that correct?

A. It's only with -- Yes, and it's only participating with that drill block, yes.

EXAMINER STOGNER: Any other questions?

FURTHER EXAMINATION

BY MR. BROOKS:

Q. Yeah, one more that I forgot to ask a minute ago. Back on your scenarios with the Drill Block B, if -- okay, if that Drill Block A and Drill Block B -- if there never were a well drilled in Drill Block A that was deemed to be commercial, then it would contract out of the unit, would it not, eventually?

A. No, that would stay within the unit, that nonparticipating well would stay within the unit.

Q. Right, if it didn't have a well -- if it did not have a well on it, it would contract, yeah, correct?

A. No, they assign the unit agreement, and all of this acreage is in the unit agreement and will not be taken out, developed or not developed.

Q. Well, isn't there commonly a provision in federal exploratory units that if they do not follow the production schedule, the exploration schedule, that the units contracts, or if -- at some point doesn't the unit contract anyway?

A. That's for a certain amount of wells. I'm not sure exactly the number. Once that certain amount of wells is met, then that unit is intact. Once that certain threshold is met, then the unit is intact as it is, and it's not an ongoing issue.

Q. This would depend on the provisions of the particular agreement and what -- how the unit had been developed, correct?

A. Yes.

MR. BROOKS: Okay, that's all I had to say, I just wanted to bring out the possibility that that could happen.

MR. KELLAHIN: It really is highly unlikely, because you'll have production in other formations that make it committed to the unit.

That concludes our presentation, Mr. Stogner.

EXAMINER STOGNER: If there's no other questions of this witness, he may be excused.

Mr. Carr, do you have any closing statements at this time?

MR. CARR: Mr. Stogner, if you look behind Tab 19 in the exhibit book you will not find a letter from Williams because I have it, and I would like to provide a copy of the letter of support from Williams Production Company, LLC. Williams supports the Application of Burlington and Conoco for increased well density and also to change the spacing requirements as they have recommended.

That's all I have.

EXAMINER STOGNER: Let's see, I believe -- and I have it in -- The Division has received several supporting letters that may or may not be behind Exhibit Tab Number 19, but those are made part of the record in this instance.

MR. BROOKS: Do you have Exhibit 20 for the record?

EXAMINER STOGNER: Yes.

MR. BROOKS: Okay.

EXAMINER STOGNER: Mr. Kellahin --

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: -- do you have any closing statement at this time?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: BLM, would you like to have a statement at this time?

MR. SPIELMAN: (Shakes head)

EXAMINER STOGNER: Okay, if there's nothing further in this matter, Case Number 12,745, I'm ready to take it under advisement. However, I would ask, Mr. Kellahin, if you would provide me a rough draft.

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: Then with that this matter will be taken under advisement, and this hearing is adjourned.

(Thereupon, these proceedings were concluded at 6:02 p.m.)

* * *

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18 October 2001

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 October 26th, 2001.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002