STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

APPLICATION OF BURLINGTON RESOURCES OIL AND GAS COMPANY FOR APPROVAL OF A PILOT PROJECT INCLUDING AN EXCEPTION FROM RULE 2(b) OF THE SPECIAL RULES AND REGULATIONS FOR THE BLANCO-MESAVERDE GAS POOL FOR PURPOSES OF ESTABLISHING A PROGRAM IN ITS SAN JUAN 29-7 UNIT TO DETERMINE PROPER WELL DENSITY AND WELL LOCATION REQUIREMENTS IN MESAVERDE WELLS, RIO ARRIBA COUNTY, NEW MEXICO

CASE NO. 11,625

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

October 17th, 1996
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner, on Thursday, October 17th, 1996, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

October 17th, 1996
Examiner Hearing
CASE NO. 11,625

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E X H I B I T S

(Continued...)

E X H I B I T S (Continued)

Applicant's	Identified	Admitted
Exhibit 10	44	55
Exhibit 11	54	55
Exhibit 12	65	89
Exhibit 13	70	89
Exhibit 14	77	89
Exhibit 15	25	55

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A P P E A R A N C E S

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By: W. THOMAS KELLAHIN

* * *

WHEREUPON, the following proceedings were had at 9:05 a.m.:

EXAMINER CATANACH: We will at this time call Case 11,625.

MR. CARROLL: Application of Burlington Resources Oil and Gas Company for approval of a pilot project including an exception from Rule 2(b) of the Special Rules and Regulations for the Blanco-Mesaverde Gas Pool for purposes of establishing a program in its San Juan 29-7 Unit to determine proper well density and well-location requirements in Mesaverde wells, Rio Arriba County, New Mexico.

EXAMINER CATANACH: Are there appearances in this case?

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

EXAMINER CATANACH: Are there additional appearances?

Will the three witnesses please stand and be sworn in?

(Thereupon, the witnesses were sworn.)

LINDA DONOHUE,

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

DIRECT EXAMINATION

BY MR KELLAHIN:

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

A. Linda Donohue, senior landman.

Q. Where do you reside and where are you employed?

A. Burlington Resources, in Farmington, New Mexico.

Q. The microphone is just for the court reporter. It doesn't amplify your voice --

A. Okay.

Q. -- so you'll have to speak up over the hum of the heater.

Have you testified before the Division as a qualified petroleum landman on prior occasions?

A. No, I have not.

Q. Summarize for us your education and employment experience in this particular area.

A. Okay, I've been employed in the land department for Burlington and its predecessors for 22 years. I have an associate degree from New Mexico State and am currently working on my bachelor's degree in business administration from the University of Phoenix and plan to graduate next

June.

Q. As part of your duties, are you regularly involved in reviewing and looking at the various unit and unit agreements in the San Juan Basin that your company operates?

A. Yes, I do, I mainly handle federal units.

Q. Is the San Juan 29 and 7 Unit one of the federal units that you are familiar with and knowledgeable about?

A. Yes, I am.

Q. In addition, have you been responsible for tabulating the interest owners that might be affected by this Application and causing those owners to be sent notification of this hearing?

A. Yes, those owners all have been contacted, and that ownership is fixed right now, due to the Mesaverde participating area being established since October 1st of 1959.

Q. Do you participate as the land-management representative on a technical team that deals with exploration and production issues in the San Juan 29 and 7 Unit?

A. Yes, I do.

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

EXAMINER CATANACH: She is so qualified.

Q. (By Mr. Kellahin) Let's go back to the specific topic of the 29 and 7 Unit itself.

The technical presentation we are about to present is the work product of geologists and engineers that have concluded they want an opportunity for a pilot project to test well density in the Mesaverde Pool; is that your understanding of what they wanted to do?

A. Yes.

Q. Have you in your capacity as the landman made a judgment or a determination that the San Juan 29 and 7 Unit is suitable for that purpose?

A. Yes, it works very well, there's no correlative-right problems, the ownership is fixed due to the fully expanded nature of the unit, which consists of all 36 sections.

Q. Let's talk about that more specifically. The target formation is the Mesaverde formation for the pilot project?

A. That is correct.

Q. How does this federal unit deal with production out of the Mesaverde formation?

A. It is all allocated based upon an acreage basis and lease ownership, and there is just no changes that will -- that are foreseeable.

Q. Did the Mesaverde formation at one point in time start out as a participating area within the unit?

A. No, it did not. Each lease was developed on its own, and as it was fully developed it ended up being fixed through time -- or ended up being fixed as of 10-1-59.

Q. All right. So regardless of where a Mesaverde well was drilled in the unit or will be drilled, all interest owners in the unit would share in that production?

A. That's correct, all infill wells have been drilled based upon that fixed ownership.

Q. Within the unit area, then, regardless of whether this well is at an unorthodox location crowding another Mesaverde spacing unit in the same unit, all interest owners in the crowded spacing unit, as well as the unit that has the well, are going to share in that production?

A. In the same ownership, that is correct. There will be no variance in ownership.

Q. Having satisfied yourself that the San Juan 29 and 7 Unit was suitable from a land perspective so that there would not be any contractual limitations on executing the technical plan from the technical team, did you cause the other interest owners in the unit to be notified of the proposed project?

A. Yes, we did. On August the 27th, we called together all the working interest owners, sent out notice to do a technical presentation to them at our offices there in Farmington.

Also, a certified mailing was sent to all the Blanco-Mesaverde operators. A list was provided to us from the Aztec, New Mexico, Oil Conservation Division Office, and we have also notified them of this Application at this time.

Q. To the best of your knowledge, Mrs. Donohue, has Burlington received any objections or opposition with regards to granting this Application?

A. No, we have not.

Q. Let's talk specifically about what the regulatory request constitutes concerning this Application, and it might be useful if we turn and find a locator map.

If you'll turn with me behind Exhibit Tab Number 2, let's pass the first two displays for a moment and look specifically at the third plat behind Exhibit Tab Number 2. Would you identify for me what we're looking at here?

A. Okay, this is a depiction of the San Juan 29 and 7 Unit, and the Mesaverde wells are spotted on there to date.

The buffer area that is around the edge of the unit is a half a section, and we are asking at this time to be able to develop, based upon increased density that we see in the unit, to have four more wells per section with a maximum of 8, all except for in the buffer-area zones on the outer rim of the unit, which would only allow to have six wells per section. It would only be the interior part of the unit that would have eight.

Q. This unit is within the Blanco-Mesaverde Pool, is it not?

A. Yes, it is.

Q. And under current pool rules for that pool, if a section is fully developed with an initial well and an infill well, then you're permitted to have a maximum of four wells in a section?

A. That is correct.

Q. And the technical team has requested the flexibility of having an additional four then?

A. An additional four.

Q. So we're dealing with potentially a maximum of eight wells in a 640?

A. All except for around in the buffer zone, where we'll only still have two. That's what I wanted to make sure everyone understood. We're not increasing the density in the outer boundary, just in the interior.

Q. So in the buffer area, then, the request is to have but one Mesaverde well in 160 acres?

A. That is correct.

Q. And what's the purpose of that?

A. It's just to prevent drainage.

Q. And it maintains, then, within the unit along the boundary, the existing pool rules insofar as the offsets are concerned?

A. That is correct.

Q. All right. Describe for us the color code for the wells shown on this display.

A. Okay, the wells in blue are the wells that have just been drilled in 1996, the infill wells. The ones that are sitting in green are the ones that are proposed for 1997, that are currently on our budget. The ones in red are the proposed -- the phase-one proposed project wells.

Q. After the blue and the green wells are drilled, will the unit be fully developed on one well per 160?

A. That is correct. That is our intention, to have all those completed.

Q. Let's talk about the pilot project, insofar as you're concerned. Is the pilot project intended to be the entire unit area, with the exception of the buffer area?

A. That is correct.

Q. So when you talk about phase one, that is simply the starting point?

A. The first eight wells.

Q. And then it would be expanded thereafter, depending upon the outcome of what the technical people determine to do?

A. That is correct, after we get results.

Q. One of the issues for you as a landman is to look at well locations under current rules and what they may be with regards to this pilot project. When we look at well locations now under the current Blanco-Mesaverde pool rules, what do they now require?

A. They require a setback of 790 feet from any subdivision line.

Q. And is there an interior setback also?

A. Yes, there is.

Q. The 130-foot?

A. 130-foot, 130-foot.

Q. All right. If the Division approves the pilot project for the unit, what are you requesting in terms of well locations for any of these infill pilot wells?

A. Okay, we want to be able to have a 10-afoot setback from any interior subdivision line, to optimize --

Q. And what's the basis for that request?

A. It's to be able to optimize drainage based upon the proximity of these wells. The original wells have all been drilled in optimal locations, based upon the current rules for locations, and so this will help optimize the project for drainage within the unit.

Q. Have you struggled with the first -- Was it eight phase-one wells?

A. The first eight wells have been difficult. We have a lot of archeological and topography problems, and we have ended up having to drill or set four of the wells as directionally drilled wells because of this reason.

Q. And this exhibit shows, then, with the dark red circle, the surface location?

A. And the dotted line.

Q. The dotted line, and the open circle indicates the bottomhole location for these directional wells?

A. That is correct.

Q. And how many are you going to have for this phase one?

A. There will be four of them, four out of eight.

Q. Let's highlight for the Examiner the difficulty that you face with regards to locating the wells. If you'll turn with me behind Exhibit Tab Number 4, identify what we're looking at when we examine that display.

A. Okay, this is a USGS topographical map. And as you can see, we do have a lot of terrain-type problem. When the stakers have been out there, we've been trying to work with them very closely in working out these locations. And right now this is the best that we have been able to come up with, based upon archeological problems in the canyons and stuff that are in existence in this area.

Q. All right, let's look at the map then. What is indicated with the black star?

A. The black stars are the locations for the eight wells, the bottomhole locations.

Q. And the number and letter, then, are the references to the --

A. -- the well numbers.

Q. -- the pilot wells?

A. That is correct.

Q. If you'll turn to the next page, there's a specific list of the footages of those wells; is that not true?

A. That is correct.

Q. In order to find the locations that the technical team wanted for the project, are any of these standard well locations under current rules?

A. No, they are not.

Q. Every one is a nonstandard?

A. Nonstandard. We are asking for approval for those.

Q. All right, let's go back, then, to the topo map and have you take one of those as an example. You may choose one; perhaps the 47B is a good example. But describe for us the kinds of things that you have to go through in this area to physically site a well.

A. Okay. Of course, the surveyor is always going to go out and do the physical location of the well, and he works with the BLM and the surface owner that's out in this area to spot the location. But for right now that is the best location that has been worked out with the geologist for the placement of that well, due to the canyons, as you can see, that run along this Romine Canyon.

Q. If the Division approves the request to have any of the project wells located within the unit area, at any location, provided it's no closer than ten feet to a quarter-quarter line --

A. Right, to the subdivision line.

Q. -- would that provide -- to the subdivision line, would that provide you flexibility in locating these wells to help achieve the objectives of the project?

A. Yes, we believe that it will.

Q. Do you see any opportunity for violation of correlative rights if that will be approved?

A. It should not be a problem since the ownership is fixed within the units itself anyway; it's just to optimize drainage.

Q. All right. Let's go back and have you identify, then, the displays that are shown. Exhibit 1 is the notice of hearing and includes the Application for hearing, does it not?

A. Yes, it does.

Q. There's a notice list attached on the end of that exhibit, at the last page. Do you see that?
A. Yes.
Q. Did you cause notification to be sent to all those parties?
A. Yes, all those partners have been notified.
Q. All right, let's turn now to Exhibit 2, and let's look at the locator map.
A. Okay. For your information, this is a depiction of the San Juan Basin and the units that are currently within that.
As you can see in yellow, the 29-7 unit is noted there. The line that is around that will be further explained by the geologist.
Q. 29 and 7 unit is outlined in yellow?
A. That is correct.
Q. And then you show the relationship of that unit as we locate Farmington, Bloomfield and Aztec?
A. And Navajo Lake.
Q. And you have -- You've also located other federal units?
A. Yes, we have.
Q. And how are those shown?
A. They're in green boundaries with the names being placed across there.

Q. And the black outline, then, conforms to the large display that the Examiner was talking about before the hearing? That shape shows him the location of the shape as he looks at the area map for the San Juan Basin?

A. That is correct.

Q. And in fact it is not Mexico, is it?

A. I don't think so.

Q. Okay.

A. I've always known it as New Mexico.

Q. If you'll look behind that display, what is the next document we're looking at?

A. The next document is a map showing all wells drilled to date within the unit itself.

Q. All right. So it would include other wells in addition to the Mesaverde wells?

A. Yes, the Fruitland, the Mesaverde and Pictured Cliffs and Dakotas that have been drilled to date.

Q. The map also shows a line of cross-section that's a locator map for a subsequent exhibit?

A. That is correct.

Q. All right. After that, then?

A. Again, this is the depiction of the eight pilot or phase-one wells that we want to drill and the buffer zone that we intend to set in place.

Q. Okay, let's turn, then, to the last display in

Exhibit 2 section, and look specifically at the initial phase of the project area.

A. Okay.

Q. How are these wells identified?

A. These wells are in red for the eight phase-one wells.

Q. And how are the other wells coded? What do the other colors mean?

A. The other colors, the blue would be a well that was just drilled this year to finish up the infill development program, and the black are existing wells that have been -- the parent wells that have been there for a while, so...

Q. All right. For illustration, let's look at Section 2 and look at the 47B well. Have you caused that well location to be moved to the south so it stays out of the buffer area?

A. Yes.

Q. And so we're trying to honor the integrity of the buffer area by maintaining these pilot wells out of the buffer?

A. That is correct.

Q. If you'll turn to Exhibit 3, what is shown on this tabulation?

A. This is a listing from our Fed 1 system that we have there in Farmington that has all the working interest owners, the committed acres that they have to the unit, their participation factor and the revenue factor that we show for them.

Q. That would be Exhibit Tab Number 3; it's the single sheet within that section?

A. Right.

Q. When you notified the working interest owners for a working-interest-owner meeting, these are the parties, then, you sent notice to?

A. Yes, they are.

Q. All right. And did you have attendance by the working interest owners that had a principal or a significant interest in the unit?

A. Yes, we did. All the major players did attend.

Q. All right. And then Section 4 we've covered. That is the topo map and the specific locations of these pilot wells?

A. Correct.

MR. KELLAHIN: Mr. Examiner, that concludes my examination of Mrs. Donohue.

We move the introduction of the exhibits that she's sponsored. They're Exhibits 1 through 4.

EXAMINER CATANACH: Exhibits 1 through 4 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Ms. Donohue, as I understand it, there's a Mesaverde well on every 160-acre tract within this unit at this point in time?

A. Not at this point in time. They plan on being done by the end of 1997.

Q. Okay, so all of this is, in effect, sort of one large participating area where everyone shares --

A. -- in production and cost.

Q. And that's as a result of their percentage of ownership?

A. That is correct, based upon their committed acres to the unit.

Q. Okay. As I understand it, the location requirements that you're proposing are 10 feet from any boundary, including the section lines?

A. Yes, sir. Any subdivision line.

Q. Are there also geologic or drainage necessities for this flexibility in locating your wells. Besides topographic, are there some geologic factors or drainage --

A. I'm sure the geologist will go into detail about what his assessment is of that.

Q. Okay. Is phase one, is that proposed to be done -- What's the timetable for phase one?

A. Right now, we look at, if we got approval of this Application, starting drilling of these wells next April, after wintering restrictions lift.

Q. Completion, do you have any idea of completion?

A. I would think completion would follow pretty close thereafter, probably within 30 to 60 days.

Q. And subsequent to that will there be some kind of an evaluation to determine the success of phase one before going on?

A. Yes.

Q. Ms. Donohue, will a subsequent witness address gas allowables in these proration units, do you know?

MR. KELLAHIN: Mr. Examiner, if I might respond, we propose to continue to manage production pursuant to the proration system. At such point in time as those allowables become a limitation on the project, we may have to come back to deal with that. But this Application does not ask any special relief with regards to the allowables.

Q. (By Examiner Catanach) Ms. Donohue, the eight proposed infill wells, you're not seeking to get the locations approved in this Application; is that correct?

A. Yes, we are asking for the unorthodox locations to be approved in this Application.

Q. The initial eight locations -- I'm sorry, let me back up here.

If we, in fact, change the rules to allow 10-foot setbacks, will any of those locations then be unorthodox? They'll still be...

A. Probably not.

Q. I'll have to figure that out.

A. Yeah, me too.

MR. KELLAHIN: They'll all be standard, Mr. Examiner.

EXAMINER CATANACH: Okay.

MR. KELLAHIN: The ones listed on Exhibit Tab 4, they become standard if you grant the flexibility.

Q. (By Examiner Catanach) Ms. Donohue, do you -- does Burlington have any plans at this point to -- in any of the proposed infill wells, to dually complete them or --

A. No.

Q. -- complete in other zones?

A. Strictly going to be single Mesaverde.

Q. These will not be later on recompleted --

A. Well, I can't --

Q. -- as far as you know?

A. -- guarantee what will happen in the future. But for right now we don't foresee that; we just are strictly going after the Mesaverde formation.

Q. And then I believe you testified that you notified all of the operators in the Mesaverde Pool?

A. The ones that were provided to us from the Aztec office, we did.

EXAMINER CATANACH: I believe that's all I have of the witness. You may be excused.

MR. KELLAHIN: Thank you.

Mr. Examiner, our next witness is Mr. Bill Babcock. Mr. Babcock is a petroleum geologist.

WILLIAM BABCOCK,

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

A. My name is William Babcock. I'm a senior geologist for Burlington Resources in Farmington, New Mexico.

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

A. No, I have not.

Q. Summarize your education.

A. I have a bachelor's degree in geology and a master of science degree in geology. I've been in the petroleum industry for approximately eight years, the last six of which have been for Burlington Resources, and the last three of which have been in Farmington.

Q. From what universities and in what years did you get your degrees?

A. My bachelor of arts degree was in 1983 from the University of Montana. My master's degree was from the University of Colorado in 1989.

Q. Questions will get easier after this.

A. Thank you.

Q. Have you and other technical people with Burlington been involved in examining the opportunity for increased density wells in the Blanco-Mesaverde Pool?

A. Yes, I have, for approximately the last two years.

Q. Have you made a detailed investigation of the geology in the Mesaverde -- Blanco-Mesaverde Pool, with specific focus on the San Juan 29 and 7 Unit?

A. Yes, that has been a part of a basinwide study, and we've looked very intensively at the San Juan 29-7 Unit.

Q. How long have you spent on this project, Mr. Babcock?

A. Approximately two years. That was -- Previous to that, we also spent -- that was part of -- The 29-7 Unit was part of my area of study for the previous year and a half.

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

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Give us some background, Mr. Babcock. Let's talk about what you and the team are investigating with regards to the well density in the Blanco-Mesaverde Pool.

A. When we began looking at the Mesaverde on a Basinwide look at it, we began to see that there were dramatic differences in the efficiency in which the reservoir was being drained across the Basin, and we began looking at those differences with a particular emphasis on those areas where we were not efficiently draining the reservoir.

Q. Mr. Babcock, the display before you is numbered out of sequence. We're going to number it 15, but it is the display I'm about to have you describe.

In order to begin to characterize the effectiveness of well density in the Blanco-Mesaverde pool, what kind of indicator did you choose to examine as one of the principal indicators to analyze that well-density efficiency?

A. One of our earliest and which turned out to be one of our best tools for looking at the efficiency of drainage was the initial shut-in wellhead pressure that is required to be gathered as each well is drilled in New Mexico, and using that data we were able to make assumptions and determinations about how efficiently the pool is being drained.

Q. What is the database, then, for that shut-in pressure data? It expands what period of time?

A. I'm sorry, yes, it began in the early 1950s, with the initial development of the pool on 320-acre spacing, and then also in the -- ever since then, this data has been gathered.

The most use to us was the initial data, compared to the data which was gathered in the drilling boom of the 1970s, so approximately 20 to 25 years' separation between the two sets of data.

Q. The Division has been making us take this pressure data for decades. Now we're finally going to do something with it, right?

A. That is correct.

Q. All right. Show us what you did with the map.

A. This map is a comparison of the initial shut-in wellhead pressure from the first 320-acre well in the section, compared to the shut-in wellhead pressure of the second well in that 320-acre block, so the 160-acre infill well, and you take the difference in pressure between those two wells and then divide that by the number of years between the drilling of those wells, and you get a p.s.i.-per-year drop in pressure. And you can map that so each data point on this well represents a parent well/infill well pair, in looking at how effectively that parent well is draining that 160-acre location.

Q. All right. Let's start first of all with the size and the shape of the area displayed on Exhibit 15. How did we get that size and shape?

A. The shape is -- and size, are a function of where there has been development at the 160-acre infill locations. So if we didn't have -- If we just had the initial development on 320-acre locations, we didn't have a data point to put on the map, so the boundaries were drawn with that in mind.

Q. Having defined the size and shape for the investigation of the Mesaverde infill program as it exists with four wells in a section, it gives us this shape. How many data points do we have as to those pressure points?

A. There's approximately 1200 data points that would be equal to the number of infill wells that fell within this area.

Q. All right.

A. Now, there's more wells in Colorado, but we didn't have the pressure data up there, so those were not included.

Q. When we look at the way the pressure map is plotted, this is color-coded, I assume, to show various increasing or decreasing rates of pressure change over time?

A. That is correct.

Q. How do we read the map, then?

A. The green areas with darker green -- the green areas represent areas of higher pressure drop per year, and the red and orange areas represent lower pressure drop per year.

In essence, this map is an indicator of the effective permeability which we see in the formation, and the range in values, in pressure drop per year, is greater than 30 p.s.i. in the darkest green areas to less than 5 p.s.i. per year out in the red areas.

Q. All right, let's take the green area. That's the area where you've examined to show the greatest drop in pressure over time. What does that tell you, then?

A. That indicates that the initial wells in the section -- that the existing wells in the section are effectively draining the reservoir, they are lowering the pressure at a significant rate.

Q. And those are pressure changes of about 30 pounds per -- p.s.i. per year?

A. 30 p.s.i. per year, 30 pounds per square inch per year, in the reservoir pressure.

Q. All right. And the lower range, when we get down into the -- What was it? The orange?

A. The orange to red.

Q. All right. The orange to red represents what rate of change?

A. Ten to less than 5 p.s.i. per year.

Q. What is the significance of choosing the San Juan 29 and 7 Unit, then, within the area of study?

A. The San Juan 29-7 Unit -- it's highlighted in black on the map -- is an area of very low pressure drop. It's from 10 to less than 5 p.s.i. in some locations. And so we had very low pressure drop. We also have economic wells in that area, so we feel that a combination of the two indicates that we can drill economic wells but that they are not being effectively drained right now.

Q. When we look at the areas that have been effectively drained compared to those that have not, is there a geologic explanation as to the difference?

A. Yes, there is a geologic explanation as to the difference.

Q. What type of things did you examine to see what you could attribute that difference to?

A. We took eight cores across the field in the high-pressure-drop areas and the low-pressure-drop areas to determine if the matrix porosity and permeability are what is causing this dramatic differences across the field. Those core locations are the red dots on the map. We took approximately 1600 feet.

I'll be summarizing some of that data later, but in essence we found that that -- the matrix properties are not what is controlling this change in effective permeability across the field and that in fact what is controlling it is the presence of natural fractures in the reservoir, and the density of natural fractures.

Q. When you're looking at the core, the matrix in the Mesaverde, then a core from a well drained area looks similar to a core from a poorly drained area when you examined only the matrix?

A. Yes, it does, very similar.

Q. What else did you examine to see if that would be an explanation as to why certain areas are better depleted than others?

A. We also used some log analysis techniques, and volumetric analysis indicated that the areas in red were not being as efficiently drained, log-calculated volumetrics versus production estimates, rate-time production estimates.

Q. Is there a structural component to the reservoir that would explain the differences in ability to effectively drain an area over another area?

A. If there is, it's certainly not very obvious. There are enhanced fractures in the areas with the green areas are. It does have enhanced fracturing, and that very likely may be tied to some structural components. But you do not see structural closures, anticlines, synclines, that type of effect. It's more -- much more subtle than that.

Q. Did you see reservoir thickness as the basis to explain the difference?

A. Absolutely not. In some cases we even saw an inverse relationship between productivity of an area and the reservoir thickness.

Q. Okay. What is the significance of the green dot on Exhibit 15?

A. The green dots are pressure-observation wells, two of which we've drilled in the last year and a half, and one of which has been in place since the 1950s, and recompleted it in an upper zone, and these wells were completed with downhole gauges in each of the three formations which make up the Mesaverde, the Cliff House, the Menefee and Point Lookout to get separate reservoir pressures.

Q. Describe for me, Mr. Babcock, why the 29 and 7 Unit is a good candidate in which to initiate this project to test the appropriate well density in the Mesaverde.

A. There's several reasons why we feel the 29-7 unit is an excellent candidate. First, as I mentioned, we have a very low pressure drop in the area. The density of natural fractures is relatively low. We also -- In the particular area we are looking at, it is fully developed, and very soon the whole unit will be fully developed on 160-acre locations. We also have a core in the unit, and we have a pressure-observation well in the unit.

Q. Let's go to the core data. If you'll start with me behind Exhibit Tab Number 5, let's look at your study of the core permeability.

A. This is a histogram, which is comprised of 1600 data points, a little more than 500 each in the Cliff House and Point Lookout and a little less than 500 in the Menefee.

And the median core permeabilities in the Cliff House are .06 millidarcies, in the Menefee .05 millidarcies, and then in the Point Lookout .02 millidarcies of permeability. And these are at bench conditions, unpressured conditions. So this is -- In the reservoirs themselves, these permeabilities will actually be lower than this.

Q. How would you characterize this magnitude of permeability?

A. Very low. Most geologic textbooks would term this as caprock.

Q. All right, sir, let's turn to Exhibit Tab Number 6 and look at the first display behind that exhibit tab.

A. This is an attempt to explain the difference between effective permeability and what we see in the core. This is a cartoon, really, showing the reservoir itself, with the wellbore cut out of the reservoir. The black areas are core plugs, indicating where the core measurements would be taken. And those would be in areas without fracturing, so that you're just measuring the permeability within the matrix of the rock itself, whereas the reservoir system includes that matrix permeability, but it also includes the presence of natural fractures, which in the case of the Mesaverde is what makes the field producible, the presence of these natural fractures. And it indicates why the permeability in the reservoir can be significantly different than the permeability in the matrix which we measure in cores, the effective permeability of the reservoir.

Q. Do you have examples of actual production tests in relation to wells that have core data so that you can compare actual core permeability to actual production?

A. Yes, we do.

Q. Let's turn to Exhibit 7 and have you show us those examples.

A. The next three plots all represent -- what they show on the left side is a cumulative production plot of the two parent wells in the section, and on the right side is the core which was taken in the past two years, showing a porosity and permeability crossplot of that core data.

Now, if you can look, in this first one it is in the 28 and 6 Unit, Section 32, we see that we have cumulative production of about 3.3 BCF to date. And these wells have about 40 years of life on them, these two wells.

And then if we look at the core data, all of the porosity is less than 15 percent, with the majority of it being down around 8 to 10 percent. Our permeability is -- the vast majority of it is less than .2 millidarcies in permeability.

If we go to the next one --

Q. Well, and the cum, then, is 2.2 BCF on this?

A. It's 3.3 -- Or, yes, I'm sorry --

Q. Yeah.

A. -- I'm looking at the EUR.

Q. 2.2 is the cum, you've got 1.1 left, and that's this two-well pair, using a porosity, a core-permeability component within this range?

A. That's correct.

Q. Now, let's compare that to another set.

A. If we look in the San Juan 29-7 Unit, in this --

these two parent wells in this section, Section 15, we have a cumulative production of just about 6 BCF, whereas our core data, once again our porosities are in the same range, our permeability is also -- the mass of the permeability is also within the same range. There are a couple of very high values there, which are most likely a function of clay laminations in the samples, which under unstressed bench conditions will give you anomalously high permeabilities, which are not representative of the matrix permeability in the reservoir.

Q. When you compare this permeability from these two wells to the last one we examined, are they in the same range of permeability?

A. Absolutely.

Q. Yet when we look at the productivity of the wells on this display, it's twice as good --

A. Yes.

Q. -- with an EUR of almost -- well, double what the first set was?

A. Almost three times, yes.

Q. So you can't explain that difference looking at core permeability?

A. No, you cannot.

Q. All right, let's look at the last display.

A. The last display is in Section 29 of 31 North, 8

West. In this area, these two parent wells have cum'd about 13.5 BCF. And once again, if we look at the permeability and porosity crossplot, we see, if anything, the permeabilities might even be a little bit lower.

I'd like to point out that on the left-hand side of this plot there are some anomalously high permeabilities, but notice the porosity that is associated with these permeabilities. It's a 4-percent porosity, which clearly indicates that these higher permeabilities are a function of clay laminations, which under unstressed conditions will give you anomalously high measured permeabilities at bench conditions. In the reservoir conditions under stress, that permeability will go away.

Q. How does this permeability compare to the other sets, then?

A. It's very equivalent.

Q. How does the productivity compare?

A. It's much better in this area than in both of the previous two areas.

Q. To what do we attribute these differences?

A. I attribute the difference to a greater density of natural fracturing in this area than in the previous two locations.

Q. All right, let's shift gears to another chapter. Let's look at the three reservoirs, if you will, that make up the principle producing intervals in the Mesaverde. We've got the Menefee, the Point Lookout and the Cliff House.

A. Correct.

Q. Let's look at how those three reservoirs in the pool correspond to each other in the way they're produced and how they look geologically. The top one is the Cliff House.

A. The top one is the Cliff House, the middle one is the Menefee, and then the bottom unit is the Point Lookout location.

Q. Okay. Let's turn to Exhibit Tab Number 8 and have you take us through this discussion.

A. These are pressure-versus-time plots from the three pressure-observation wells which we've drilled in the Basin.

The first one is the Mesaverde Strat Test Number 2. And what we see in this is that the Menefee pressure, which is in blue, is essentially at virgin reservoir pressure. Even though there have been wells surrounding this pressure-observation well for over 40 years, we find that the Menefee has not been drained at all.

The Point Lookout and the Cliff House, they have been -- the pressure has been lowered, but it's important to note that they are at different pressures today and that they are declining at different rates today, indicating that there is clearly separation within the reservoir.

The next one is the Atlantic C Number 4B. Once again, we see that the Mesaverde is at virgin reservoir pressure in this area.

And then the Cliff House and Point Lookout are at significantly different pressures and once again are declining at different rates.

And then the final one is in the San Juan 29-7 Unit. It is the Number 300 Pressure Observation Well. And in this one we see that the Menefee also has the highest pressure, but that it is declining at a significant rate. But it's important to note that if that was projected back up to virgin reservoir pressure, it appears that it was only -- began draining about two or three years ago, when we added pay in a well several sections away. It was completed all around this pressure-observation well when we completed it, but it appears that it is being drained from a well --

Q. All three of these are pressure-observation wells?

A. They are.

Q. Do you have a geologic opinion, Mr. Babcock, as to whether the existing well density that we have under the current rules of four wells to a section is adequately and effectively accessing and developing the Menefee reservoir in the pool?

A. I do not feel the existing locations are adequately developing the Menefee formation.

Q. Let's turn to the next set of displays and talk about what you as a geologist see as the distribution of these reservoirs in the Mesaverde, and let's go to the photographs.

Smaller copies of the photos, Mr. Examiner, are also contained behind Exhibit Tab Number 9, but we've enlarged those so they can be put on the display board.

Mr. Babcock, were you present when these photographs were taken?

A. Yes, I took the photographs.

Q. And where were you when you took them?

A. I was at the Lee Ranch Coal Mine, which is near Grants, New Mexico. This is a coal mine within the Menefee formation.

Q. Do the photographs accurately depict what you as a geologist could see when you were at the surface looking in this direction where the camera is taking its picture?

A. Yes, they do.

Q. Describe for us where we are, what the orientation is and what we're seeing.

A. May I stand?

Q. Yes, sir.

A. This is an open-pit coal mine, and we have a high wall which is approximately 120 feet high. The scale is somewhat misleading here in this photo. We can see the dragline down on this end.

And what I wanted to show was the highly discontinuous nature of the Menefee and how you may be misled in just looking at logs on a 160-acre location. Here I've outlined -- Because of the lack of contrast of the sands, silts and shales, I've outlined the sands in black marker.

But if we look, here's one of the larger sands that we saw. I've taken two trips to the coal mine, and this is about the largest sand that we saw. But you can see even this sand had pinched out on this upper end. And then we had another sand which started up not too far away from this one.

Now, if somebody had drilled a well over here and then drilled a well into this sand, clearly drawing a cross-section would have connected those up, but you would be in error in this instance.

Also, we have discontinuous sand lenses here, here and up here. Significant amount of discontinuity of the sand layers, lack of connectivity within the Menefee formation. Now, the Menefee was deposited in a fluvial deltaic environment with a delta which was composed of meandering river systems and swamps which generated the coals, and so that's the reason for this discontinuity in the sands.

If we look at this other picture, the lower picture, we see an even better example on a smaller scale. We have a very thick sand, which very abruptly pinches out and then starts up again right here with some smaller discontinuous sands above it. But a well here and a well here, which would only be about 400 feet apart, you would clearly draw those as being straight across, assume that you have pressure communication between those sands when in actuality you don't. These sands are not in pressure communication in this field.

Q. Let's turn to the cross-section that you have prepared. It's, I believe, Exhibit Tab 10 -- I'm sorry, that's too far; it's the last package before we get to 10. It's the pocket. If you'll take that cross-section out, Mr. Babcock, let's examine that one.

Ms. Donohue gave us a line of cross-section for the three-well cross-section. It was the second display behind Exhibit Tab Number 2. This is an area moving from northeast to southwest, just to the south of phase one of the infill pilot project. Why did you choose these three wells?

A. The reason I chose these three wells is because they're closely spaced, and also the center well is the core well, the San Juan 29-7 102A. We cored approximately 200 feet in this well.

Q. When we look at just the Menefee portion of the pool, describe for us what you see as a geologist when you look at the cross-section.

A. I see a very discontinuous, yet very sand-rich, interval in the Menefee. It's very difficult to know what is happening between the wells at this location, but this is clearly a fluvial deltaic system, with some of the sands quite possibly being continuous from well to well, a significant number of the sands clearly not being continuous from well to well.

Q. When you as a geologist are looking in your bag of tools to try to figure out geologically the size and the shape of these various containers and you would map this in a conventional way, what do you do?

A. You might do -- You would probably connect these sands up across or go from well to well and average certain intervals within there and say you have certain number of net sand, and then you would post those data points on a map and contour between those data points so that you would have very much of an averaged map. But by necessity, by averaging like that, you are assuming a connectivity of the reservoirs.

Q. Does the industry now have better tools to use to more accurately map and depict complicated reservoirs like the Menefee and the other members of the Mesaverde Pool?

A. Absolutely.

Q. Is there a label to put to this new tool?

A. Yes, geostatistics and stochastic modeling.

Q. One more time?

A. Geostatistics and stochastic modeling.

Q. All right, what does that mean?

A. What does that mean? That is a method by which you can capture the -- quantify the correlatability and directionality of the existing data, but then you can also distribute data between those data points in a non-averaging method. You can still use the geologist's knowledge of the area and impart that to the system, but you do not have to average across your units when you make your geologic model. And you build a geologic model in a three-dimensional sense, which is very important. And you get a more realistic distribution of reservoir properties, which can be input into the reservoir simulator. Rather than averaging everything, you are trying to get a realistic input.

Q. The Commission has seen numerous presentations by reservoir engineers where they will model a reservoir in its performance using computer assistance and they will computer-model -- history-match a particular parameter and then forecast reservoir performance.

Is that what we're talking about in the geologic sense, that you now have the ability to utilize highly sophisticated computers to help you generate very sophisticated geologic maps?

A. That is correct.

Q. That's what we're talking about, is it not?

A. Yes. Yes, it is.

Q. Let's turn to Exhibit Tab Number 10 and have you lead us through the process by how you as a geologist now utilize this new industry tool to prepare these geostatistic models.

A. Okay. The first one is just explaining why we feel that geostatistics is important, and the main reason is that for reservoir simulation, as I've stated, conventional geologic models often give unrealistically simple flow geometries for reservoir simulation.

In a conventional geologic model, you're assuming that the gas flows in a straight line, in a homogeneous system, and that's not the way it happens in the reservoir. So geostatistics attempts to capture that.

It also can measure the uncertainty in the geologic interpretation based on the well density.

Q. Okay, describe for us how it works.

A. What it does, it combines the hard data, which in this case, the geologic model was over a nine-section area, and in that nine sections we had 30 wells. That's our hard data. All of that data was honored on a foot-by-foot basis, rather than averaged.

We also used the variogram.

Q. Okay, time out. Let's get the picture up, and show us what a variogram is.

A. The variogram is a -- it's a spatial model of the correlatability and orientation of a geologic structure or a geologic system.

So in this case, this is obviously a very simplified diagram of an anticline dropping into a syncline and then leveling off out here, also getting more level in that direction, and I've posted idealized locations for wells on here so we have the perfect orientations.

Now, intuitively you can determine that in this direction (indicating horizontal row of dots) we see more correlatability than we do in this direction (indicating vertical row of dots). We would be able to predict what our elevation is going to be moving in this direction (horizontally) much better than in this direction (vertically). Things are changing more rapidly when we go downdip than along strike.

Q. You're going to have to help the court reporter by describing the direction you're pointing, as opposed to saying "here".

A. Okay. If we go horizontally across this picture, we see greater correlatability of the system, which is along strike of the structure, versus if we go vertically along the picture, which is down the dip of the structure, we see much less correlatability.

Now, the variogram quantifies this correlatability and directionality by making a plot, essentially, of distance on the X axis, and that is distance between points.

So if we think of going from this centermost -- center point, in the first one we'll go in the dip direction, which is vertically on this chart. We go one data point away, a small distance, we find that we have a certain variance; it changes by so much. Then we move two data points away, and that variance increases even more.

At some point we reach our maximum variance of the system, we're out here (indicating top vertical point), where this data point is no longer of any use in correlating what we see out here. This data point is no longer of assistance in predicting what our data element is going to show out here, up to the -- vertically, to the higher on the chart.

If we go in the horizontal direction, strike of the structure, where we can see that we have a greater correlatability, the variogram confirms that.

Moving in this distance, we can see that the early time plot -- the early time data of the plot, has a much lower slope than what we saw in the dip variogram, so that our correlatability is greater. We can go out a longer distance before we lose our correlatability.

Moving farther away from this point (second point from left in horizontal row) we can predict what we're going to find with some confidence a greater distance than what we can in this direction.

Now, what the variogram does in the software is that you build these models in 360 degrees. You're essentially building this model for every orientation. In practicality, you only have to build it for the maximum and minimum orientations, and then it interpolates between those.

Q. What's the objective obtained, then, by using the computer assisted variogram technology to generate this geostatistic model?

A. The objective attained is that we can create a very detailed geologic model which preserves the orientation and correlatability of the data; it best honors the existing data.

Q. And without the use of this tool, then, you as a geologist would use a conventional way of mapping and take two data points and simply draw the line between them?

A. That's correct, you'd have to average between those data points.

Q. And this will take the raw data and statistically determine how to distribute those property values between the data points?

A. Yes, it does. It distributes the data between those data points, it honors all the data points and uses those existing data points to distribute between them, maintaining the statistical integrity of the data.

Q. For this particular project -- We often talk about the reservoir engineer adjusting certain parameters in his modeling in order to get a history match of some known data.

What do you do, first for input parameters, and then how do you achieve what I would characterize to be a history match? What are you doing with the model then?

A. The reservoir engineer is probably more qualified to answer what is needed to get the history match.

Q. No, I'm talking about in a geologic sense when you construct the geostatistic model, you are the inputter of the data.

A. That's correct.

Q. What data do you put into your model?

A. Okay, the data I put into the model is essentially my -- all of my core data. And we have a porosity/permeability tied to that data. So we're putting in our core data on a foot-by-foot basis, mainly porosity. We're also putting in whether it is sand, silt and shale, also on a foot-by-foot basis. And then from that data, using the software, we can calculate what the distribution of these different facies are within the logs, the existing logs. And that distribution is preserved in the final three-dimensional model. Also, we build the variograms from that data, and the combination of the hard data, the variograms and the statistics of that hard data, we generate an output model.

Q. As part of the input data, do you as a geologist select any particular porosity cutoff for the values of the data going into the model?

A. No, I do not. Particularly in a fractured reservoir, I don't feel that porosity cutoffs are a proper tool to use.

Q. Okay. Let's go to the displays that show the end result of the analysis, then, using geostatistical modeling. If you'll turn to the --

A. Okay. This first map is a one-foot-thick slice within the Menefee formation. And as you can see, this is very different from the conventional geologic mapping. Essentially, permeability and porosity are distributed similar to what we see here. This is the facies, sandstone versus shale and siltstone.

I'd like to point out the north arrow, the orientation of the north arrow. It's not straight up, as is conventionally the case, and that was a limitation of this software, this particular software package we used. Our model was aligned with the main fracture direction, and that's why these displays are somewhat skewed.

But the connectivity of the sands appears to be greatest in the northeast direction, which is consistent with published and personal interpretations of the Menefee-formation channel orientation, the orientation of the sand channels themselves.

Q. When we look at the color code, then, it's obvious that we would like not to have penetrations in the purple?

A. That's correct.

Q. And you would hope that your wells were located such that you could access the Menefee sandstone, which would be the -- What is that, yellow or the orange-shaded --

A. The orange, yes.

Q. So what are the black dots, then?

A. The black dots represent the well locations where we had hard data points in this -- in the reservoir, or in this nine-section area.

Q. Does this analysis at this point give you any ability to reach conclusions about whether or not the current well density in the Mesaverde is sufficient?

A. It would be very difficult, but what you can see is that there are significant isolated sandstones within the reservoir. That you can see, but it's more quantitative to then take it into a reservoir simulator.

Q. Have you taken this information and built a larger display that would show us a bigger area? Is that not what the next one is?

A. The next one is actually a cross-section view --

Q. All right.

A. -- across the same area.

Q. I've misunderstood, then. We're looking at a cross-section view of the same area?

A. Yes.

Q. Describe for us what we're seeing in the cross-sectional view.

A. This is showing the whole Menefee formation. Now, the previous picture was a one-foot-thick slice within the Menefee, at approximately 100 feet from the top. This is a cross-section showing the whole Menefee formation in this area. It's approximately 300 feet thick. And once again, the orange represents sand, and then the purple and grayish-blue represent shale and siltstone.

But you can see that there is some continuity in this direction. And this is the northeast direction. I apologize, I didn't have the cross-section plotted on the map view. But you can see some sense of connectivity of the sands, of some of the sands in that direction, with the -- but also you see that there are a significant number of sands which are not connected.

Q. What's the end result of the entire process, then, as you begin to work with the engineer to develop some collective conclusions about the Mesaverde? What do you do with all this stuff?

A. What we do with this geostatistical model then is, we output this into the reservoir simulator to give a more realistic flow simulation of the reservoir.

Q. In other presentations before the Division, it's common strategy to attack the reservoir engineer's model, based upon looking for judgments made about the geologic values put into his model. And that really is common strategy, to look at his conventional geologic parameters.

Does this allow the reservoir engineer to have a more sophisticated geologic model to begin his work with?

A. Not only more sophisticated, but also a much more realistic geologic model.

Q. From a geologic perspective, what do you hope to achieve if the Division approves the pilot project for this unit? What are you looking for?

A. I would ultimately like to see more efficient drainage of the reservoir.

Q. And how do you think approval of this project will provide you an opportunity to gather that data, to make that determination?

A. In a gas reservoir, the key to efficient drainage is looking at, are you lowering the pressure in the reservoir? So --

Q. I guess my point is, can we take your geologic work at this point and simply make a judgment about increasing well density in the Mesaverde, or do we need a pilot project?

A. Oh. Yes. I feel that we definitely do need a pilot project in this area to -- the only way to really know is to put wellbores in the ground. We can do our best technical work and look at it in the best ways possible, using the most modern technology, but we have to get some wellbores to confirm this.

MR. KELLAHIN: That concludes my examination of Mr. Babcock, Mr. Examiner.

We move the introduction of the exhibits he sponsored; they're Exhibits 5 -- Oh, I'm sorry, I've skipped a section on you.

Q. (By Mr. Kellahin) Let's finish that up, then, Mr. Babcock. Let's go to Exhibit 11, Mr. Examiner, and look at the rest of the geologic displays, if you'll start with the first display.

A. This is a localized look at the p.s.i.-per-year map, which we previously had on the enlarged view, just showing the local variations within those values. The next map with -- Excuse me, the yellow in this case being the higher pressure drops.

Q. I'm not with you yet. The first display shows the pressure-rate change, map Exhibit 15, enlarged and using only the 29 and 7 Unit?

A. That is correct, that is correct.

Q. All right. The next display?

A. The next display is a structure map on the Menefee formation, and what it shows is that within the unit essentially we have a homoclinal dip across the section, with a small feature moving up diagonally through the unit. But this small feature which extends from southeast to -- or southwest to northeast, is not significant enough to have an impact if you look at the contour-interval spacing.

Q. And then the last display?

A. The last display is an original gas in place, and this gas in place is determined from a naturally fractured log analysis, and this is assuming 1300 pounds original pressure in the reservoir. And we see changes across the unit, but not significant changes.

Q. You also assisted the reservoir engineer in providing the data so that he could calculate volumetrically the gas in place and to go ahead with his study?

A. Yes, I did.

MR. KELLAHIN: All right. That concludes my examination, then, of Mr. Babcock.

We move the introduction of his Exhibits 5 through 11, plus Exhibit 15.

EXAMINER CATANACH: Exhibits 5 through 11 and 13?

MR. KELLAHIN: 15.

EXAMINER CATANACH: 15. -- and Exhibit 15 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Babcock, you seem to have concentrated your efforts on the Menefee. Is that the predominant producing zone in this formation?

A. No, it is not. We've looked at the Point Lookout and the Cliff House in as much detail as the Menefee. The

Menefee has the most dramatic heterogeneities of all the formations, and that's why I've concentrated on that. We feel there's a very clearly significant amount of waste in the Menefee. There's also a significant amount of heterogeneity in the Cliff House formation, and there quite likely is some waste occurring there, but we have not focused on that for this particular presentation.

Q. Can you quantify which interval, or can you estimate at what ratio these intervals give up -- or produce at?

A. Our reservoir engineer would probably be more qualified to answer that question. We have done some production testing using spinner surveys in the area, and I should probably defer that to Robin. I'm not sure of the exact values.

Q. Okay.

A. All three zones were contributing significant amounts of gas, so...

Q. Tell me again how you constructed your pressure-drop map. You took the initial pressure from the parent well at the time you drilled it?

A. Uh-huh.

Q. And then you took the same pressure at the time you drilled the infill well?

A. It was the pressure on the infill well.

Q. Okay.

A. So the pressure points were at 160 acres separation.

Q. Uh-huh.

A. So -- And then divided that by the number of years between the drilling of the wells.

Q. So the pressures that you're recording are for the entire Mesaverde formation and not for any one interval?

A. That is correct, average pressure.

Q. So you don't know exactly what pressure drop has occurred in any one interval?

A. No, we do not, and that's why we felt it was necessary to go out and drill some pressure-observation wells, to see the differences.

Q. What evidence do you guys have of the natural fractures in the Mesaverde formation?

A. There are several lines of evidence. All of our cores encountered natural fractures. We saw mineralized -- partially mineralized fracture surfaces on all eight cores we took. The one core in the highly productive area, the example I showed, from the 31 and 8, I believe it was, the Hall D2R, portions of that core came up as rubble, it was so highly fractured. The other areas were not that highly fractured.

Also, using naturally fractured log techniques which have been published by Roberto Aguilara in several different locations we can quantify the amount of fracturing from log analysis, and that also seemed to indicate that we had significantly more fracturing, which corresponded with the pressure-drop map.

And we ran several types of advanced logs, only in a few wells, because most of our wells are drilled with air, so we had to fill the holes with fluid to run imaging logs and dipole sonic logs, which can identify fractures. And then those tools also indicated that we had fracturing in the reservoir.

Also, we found significantly higher permeabilities from single well tests than what we saw in core data, type-curve matching.

And Robin, the next witness, could probably go into more detail on that. But the fact that we found higher permeabilities from well tests than we found from cores also indicates that there's something else impacting the reservoir, which is natural fracturing.

Q. So did you find natural fracturing in all three of the intervals?

A. Yes, we did.

Q. Was the Menefee the most predominant or --

A. Actually, the Menefee was the least naturally fractured of the units. It's slightly more shaley than some of the -- than the Cliff House and the Point Lookout, and the presence of shale will somewhat reduce the amount of natural fracturing.

Q. Is there a predominant fracture orientation in these wells that you saw?

A. Most of the data in the Basin, imaging data, indicates that the natural fractures are from north to north 40 east in orientation. That would be the strike direction of the fractures. Some interference testing also confirms that that is within reason, that that is the range -- orientation that we saw. So several different data sources.

We weren't able to orient our cores, because since the holes were drilled with air, the orientation tools that you conventionally put in the wellbore are destroyed because of the -- Drilling with air is a very abrasive -- abusive environment to sensitive tools.

So we weren't able to orient our cores to get the actual orientation of the fractures.

Q. So your -- I guess your belief is that natural fracturing or the absence of natural fracturing controls whether or not a 320-acre proration unit is going to get drained or a 160 is going to get drained, and is it also your belief that the presence -- or discontinuous nature of the sands is also contributing to whether or not that's going to be drained --

A. Yes.

Q. -- both those factors?

A. Yes, I do. The fractures themselves are the permeability system, but the storage is within the matrix.

Q. Did you find any evidence of a discontinuous sand nature in the Point Lookout and Cliff House intervals?

A. In the Cliff House we did. In the Point Lookout, some of the very thin bedded sands in the lower portion of the Point Lookout appeared to have a discontinuous nature. But in general, the Point Lookout is the most continuous of the units.

The Cliff House -- The Cliff House is primarily a distributory channel environment, very near the coast, so there is some discontinuous nature to it. But it's such a sand-rich environment that the channels are cutting into other channels, so that there is probably a reduced permeability between those channels, but there may be some communication.

Q. In some of the areas that you had a small pressure drop, did you look at maybe a cross-section between the parent well and the infill well, to see if there were some discontinuous sands in that area?

A. In all areas, after -- especially after visiting the mine, I'm convinced that based on logs, you just cannot determine -- and also from our experience from the pressure-observation well, it's impossible to determine if the sands are continuous from one well to the next.

In those pressure-observation wells, where we completed those wells, we're very specific in completing -- particularly in the Menefee, in zones that, based on cross-sections from wells in all directions with completed Menefee intervals, that those sands were definitely going to be completed, and we would see the effective reservoir pressure, and we found virgin reservoir pressure. So cross-sections were wrong in those cases.

So I would say that conventional cross-sections cannot tell you whether or not the Menefee is connected across the zone.

The Cliff House formation, the Cliff House -- We do see changes in the Cliff House across the zone, and that occurs across the whole Basin.

So I guess the answer to your question is that I don't feel, based on cross-sections I've done, that that can explain the differences in pressure drop.

Q. So all the data that you generated with your variogram and all of that, it's just a tool to utilize in the reservoir simulator?

A. It's a tool to prepare a more accurate geologic model, yes.

Q. Can that data help you choose well locations?

A. We did choose the well locations in the reservoir simulator, so yes, yes.

Q. So you -- The phase-one area, you picked that area because of the low pressure drop in the area?

A. The low pressure drop, and also we had our pressure-observation well and the core data nearby.

Q. When you drill these infill wells, how do you know whether they're going to be -- whether they're a success or not, as a geologist?

A. I guess once again, I probably should defer the question to Robin, but I'll try and give you some kind of an answer, and then hopefully you'll ask Robin for a more detailed answer.

I feel that when we go back in after the drilling of these wells and do another reservoir simulation and either confirm or disprove our original assumptions, we're going to have eight more wells -- or -- eight more wells in a relatively small area. We'll have a lot better geologic control, and we'll have a lot more engineering data to constrain the reservoir simulation.

So that would be my opinion. The simulator will have to tell us if we get an accurate match again.

Q. After phase one, how would you target your --

where you're going to drill the next wells within the unit?

A. I think we would go to another area within the unit with a similar pressure drop but with different geologic characteristics, somewhat different. Although the unit is fairly consistent, there are some small variations. And we would try and evaluate it in another area similar -- using those criteria.

And then a comparison of those two areas, hopefully by analogy we can determine whether the whole unit is -- to go ahead and develop the full unit or to maintain it on a limited basis.

EXAMINER CATANACH: I have nothing further of the witness.

MR. KELLAHIN: Next witness will probably take 40 minutes. Do you want to take a break?

EXAMINER CATANACH: Yeah, let's. Let's take ten minutes here.

(Thereupon, a recess was taken at 10:33 a.m.)

(The following proceedings had at 10:50 a.m.)

EXAMINER CATANACH: Call the hearing back to order, and turn it over to Mr. Kellahin.

MR. KELLAHIN: Mr. Examiner, I'd like to call the reservoir engineer for Burlington who's worked on this project.

His name is Robin Hesketh, H-e-s-k-e-t-h.

ROBIN HESKETH,

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

A. My name is Robin Hesketh. I'm an engineering advisor with Burlington Resources in the San Juan division in Farmington, New Mexico.

Q. On prior occasions, Mr. Hesketh, have you testified as a petroleum engineer before the Division?

A. No, I have not.

Q. Summarize for us your education.

A. I have a bachelor's of science degree in petroleum engineering from the Colorado School of Mines in 1981, and I've been working in the industry since, both domestically and internationally. The last three years I've been working in Farmington, New Mexico, for Burlington.

Q. How long have you worked on the project for considering increased density in the Mesaverde Pool in the San Juan Basin?

A. I've been part of the Mesaverde infill team for two years now.

Q. As a result of your work, do you now have recommendations and opinions with regards to a pilot project in the San Juan 29 and 7 unit to test the well density that's appropriate for the Mesaverde Pool?

A. Yes, I do.

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

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let me have you turn to the first illustration I'd like you to discuss, Mr. Hesketh. It's found behind Exhibit Tab 12. Mr. Babcock described Exhibit 15, which is the map that shows the rate of pressure change over time in the San Juan Basin.

I would ask you to summarize for us what part of this study you participated in and then let me ask you some conclusions followed by a discussion of your displays. So describe for us your study, and then we'll talk about your conclusions.

A. As Bill had mentioned, the first part of the study was -- one of our -- part of the scoping exercise was to create this map. And then the next part of the study was to try to explain why the pressure difference existed.

Q. When we try to explain -- Well, first of all, we're trying to quantify how effective the existing wells are in producing Mesaverde gas.

Have you made a comparison to show what kind of recoveries have been achieved in terms of gas in place in various parts of the Basin?

A. Yes, we have.

Q. Let's look at some of that now, then. You've got some pie charts, I think, that help us illustrate some of that.

A. Yes, in the first graph here you see four pie charts, and what we've done is, we've taken the volumetric gas in place that Bill has calculated from using naturally fractured log analysis techniques, and we've compared that to estimated ultimate recovery as determined by decline curve analysis on every Mesaverde well in the Basin. And we found some interesting trends.

What you see on this first chart as the blue color to the chart is the estimated ultimate recovery, and the red part is the part that we are currently saying will not be recovered.

Let me back up one minute. What we took was 80 percent of the original gas in place to construct this map, to -- because they -- No, I take that back. These were constructed with 100 percent of the gas in place, and we've divided the estimated ultimate recovery in here to determine our recovery factor.

And what you'll see on this first map is areas that Bill and I have been able to designate as fractured areas, areas with increased natural fracturing. And you can see very high estimated recoveries, 80 percent, 70 percent, 60, 76 percent. So very good recoveries in these areas with natural fractures.

You can see these areas on the map. They correspond very well to the high-pressure-drop area. For instance, the fractured 30 and 6 unit would correspond with this green section here on the map over the 30 and 6, 30 and 7 Unit. That high-pressure-drop area, you can see, we had estimated a recovery from the current well spacing -- from the current wells in the unit, of about 81 percent.

And some of the other fracture trends are very similar. We have a fracture trend up in here around the 30 and 10, 30-11 Unit, which on this chart is listed as the -- Oh, sorry, 32-10 up in here. This is listed as your 32-10 area right in there, the lower one.

So we see a relationship between recovery factor as predicted, the comparison between decline curve analysis and gas in place and the p.s.i.-per-year-pressure-drop map.

Q. When we look at the first set pie charts on this page, then, we're looking at areas where the four-well-per-section concept that's currently in place in the rules is providing an opportunity to recover 60 to 80 percent of the original gas in place in those areas?

A. Yes, very effective drainage.

Q. So that's working reasonably well on that density?

A. Yes.

Q. Have you contrasted that to other areas of the Mesaverde to show what's happening in other portions that are not as effectively being drained?

A. Yes, on the next page what you'll see is, we'll look at the recovery in areas where -- which has less natural fracturing. These would be the areas with the lower pressure drop, probably below about 15 p.s.i. per year. And what you see is, EURs 25 percent, 47 percent, 21 percent. So there's significant waste going on in these areas with the current wells that are in the ground.

Q. And again, the pie charts refer to a Township 29 and 9, and then the upper left-hand one shows the 29 and 7?

A. Right, these are the trends. They kind of go outside the unit, the trends marked by, again, this transition zone here. the one that's listed 30 and 6, 29 and 7, goes throughout the 29-7 Unit. But you've also got a section that comes up here into 30 North, 7 West, up in here.

So it goes across those boundaries. It's to try to locate you on the map.

Q. Your decline curve analysis for wells in those trends has been forecast to show us what you expect to be the ultimate gas recovery using the existing four-well-per-section density?

A. Yes.

Q. And then for the 29 and 7, that efficiency is only about 25 percent of the original gas in place?

A. That's for that whole pod, and that goes out of 29 and 7. If you look at the next chart, I can show you specifically for the 29-7 Unit itself.

Q. Let's do that.

A. Now, this is just inside the unit boundaries on this map, and as you can see, we're recovering -- We have an EUR on the existing wells, the green slice is the wells we're going to be drilling to finish out the 160-acre spacing, and that will bring the recovery factor up to about 51 percent in that unit.

Q. By conventional analysis, volumetrically gas in place or decline curve analysis, we're seeing within this unit we're going to leave about 50 percent of the recoverable gas still in the ground, using current well density?

A. Yes, we are.

Q. So the obvious challenge for you now as a reservoir engineer is trying to quantify how many more wells you want to attempt to drill within the unit in order to more efficiently and effectively capture these reserves?

A. Yes, that was our goal.

Q. So how do you go about it?

A. Well, we started -- To answer that question, the only real way we could come up with was to try a reservoir simulation on the area.

Q. Tell us how you put together the simulation.

A. Well, as you just got a detailed on how we created the geologic model, the first thing we did was to try to understand what affected the model. And we did a small two-well simulation that tried to determine the nature of the beast, so to speak, to see what factors were important.

And it came out that describing the Menefee in adequate detail was the most important factor in simulating this. And that's when we started on the geostatistical model in order to describe the Menefee better, and Bill's walked you through that.

Q. Let's turn to the next display, behind Exhibit Tab 13. Look at the unit area map and then identify for us the area that was simulated.

A. Yes, the area that we simulated is outlined in black on this display. It covers Sections 1, 2, 11 and 12 of the unit.

Q. All right. You have to now construct a size and the shape for which you want to simulate performance. How did you go about designing a shape for the model?

A. To design the overall size, it was a tradeoff between wanting to do a large enough area and wanting to get a simulation run done in a reasonable amount of time. So it came down to how small you wanted your grid cells, and we ended up with grid cells that were about -- between five to ten acres in size, and that would give us a reasonable run time, so we could get it -- rather than having a simulation that ran -- you could only make one run a day, we could simulate this in a reasonable time. That's how we came up with the four-section area.

Q. Why did you select these particular four sections up in the northeast corner of the unit?

A. Okay, one of the reasons, as we mentioned before, it has a low pressure drop, so we thought it was a -- Before we even started, we though it had a good -- it was a good candidate location for increased density.

It had all the wells drilled in it currently on production, excepting for one. I had a POW well in it so I could have some reservoir pressure for a history match. And I have a core well nearby, so that helped us define some of the reservoir properties like porosity and permeability.

Q. Let's turn to the next display after Exhibit --

this first exhibit behind Exhibit 13, and have you show us how you have constructed the model to establish the size of the container and what you've done to establish what I would characterize to be a no-flow boundary within the study area.

A. Yes, what we have taken -- What you see here is a map view of the grid. This is on top. This is a -- the four-section model. There were 18 layers to this model.

What we have done to create the no-flow boundary is use the edge -- boundary wells and edge wells concept. In other words, you can see along the active cells, all along the edges and in the corners you see existing wells.

Now, a well in the corner, we assume that one quarter of the production was coming from inside the simulation area and three quarters was from outside.

And again on the edge wells, we used -- assumed that one half of the production from those wells was coming from inside the simulation area and one half coming from outside.

So this in effect set up the no-flow boundary for these wells and created our volume that we were going to use for our simulation.

Q. Okay. What then did you do?

A. After -- As I mentioned, there was 18 layers to this model on top of these grids, and what we then did was proceeded to try to history-match. And our first match is shown on the next page.

Q. What value are you trying to match?

A. What we're trying to match here is the initial shut-in pressure that is recorded on these wells. And I'd like to point to the time scale on the bottom. That's a 43-year time scale on the bottom. What you see is, as the wells came on production in the unit, as they were drilled and the initial shut-in pressure was recorded, we're able to match that to the average model pressure. And again, that match you see there is 43 years in duration, so quite a long match.

Q. In order to match pressure, what do you as a reservoir engineer do to adjust other parameters, to make the performance of each individual well in the model match its pressure history?

A. Okay, in the model, we are giving the model the well's production rate, and it's predicting a pressure response from that given rate.

In this particular case, we used the monthly production history from these wells, so there was a time step every month. There was also an included time step for the seven-day shut-in, so we can model the seven-day shut-ins that we record every two years on these wells, as required by the State.

What you see on this first chart is, you see the model average pressure compared to the initial shut-in pressure. And in gas reservoir engineering we -- the wells -- All these wells throughout time, you're voiding, you're taking the gas out of your tank, and after you match pressure response with time, you basically have assured yourself that you have the tank the right size.

So what this first graph does is tell me, yes, I've got the right amount of gas in my tank. So it doesn't tell me if I have it distributed in the tank correctly, but it tells me overall I've got the right amount of gas.

So I was very happy to get this match on this first page.

Q. When you've matched the volume, how do you then allocate that gas to individual wells in the model?

A. Okay, if you go to the next display, what you'll see is a pressure match on individual wells, and we did it from every well in the model.

What you're seeing here is, again, every two years we do the deliverability test where there's a seven-day shut-in, and what you see in the upper crosses in black, that's your seven-day shut-in pressure measurement recorded by the State. The bottom is the flowing wellhead pressure that is also recorded at the same time. What you're trying to do is get the pressure response of the well to match the shape of that.

And also there's the initial pressure match in the top, the first point.

Q. In order to get the individual wells to match their pressure profile, what values or parameters do you adjust?

A. Okay, the two things I adjusted in my model were -- You adjust the effective permeability in the X and Y direction, and you also adjust the skin at the wellbore. Those were the only two things we adjusted.

Q. Were you able to make those adjustments within the range of reasonable calculations with regards to those values?

A. Yes, we have shown from using type-curve matching techniques, the Fetkovitch type curve, we have been able to estimate effective permeability on individual wells, and we saw an average permeability of about .04 millidarcies in here.

In my model when you take the average permeability from the KX and KY direction, I ended up with about .05, very similar.

Again, when you do the Fetkovitch type-curve analysis, you're able to calculate a skin factor. And my skin factor is in the model and -- being very similar to the skin factors that I found from the Fetkovitch type-curve analysis. So I have good correlation between the two different techniques.

Q. Okay. Were you able to match the observed pressure in some of your pressure-observation wells and to divide this, then, among the three reservoirs in the pool?

A. Yes. If you look on the next slide, what you see is -- at the very end in black you'll see the POW data.

Now, again, the time scale along the bottom is four years, and I should have -- 43 years, and I should have shown you that on the previous slide. Again, these are very long history matches.

What you're seeing here is the model pressures predicted by formation for the Cliff House, Point Lookout and Menefee. What this shows us is that in the Cliff House and the Point Lookout I've got a very good pressure match. After 43 years, I'm able to match the pressure in the pressure observation well.

You will notice, however, that I did not match the pressure in the Menefee, and that's in part due to the discontinuous nature of it.

But if you recall the first pressure map I showed you where I've got a pressure map for my overall volume, which showed my overall tank was the right size, and now I've got a pressure map on two parts of my tank. By default, the third part has the right amount of gas in it.

I just don't quite have it connected to -- to the wells correctly.

Q. Is that difference of significance to you in forecasting conclusions for this case?

A. No. No, it's not.

Q. Having achieved the match, then, you run the computer and have it forecast what will happen?

A. Yes, after you get a satisfactory history match, we then run a production forecast.

Q. Did you run those production forecasts with various assumptions as to well density?

A. Yes, I did, I used -- The assumptions I used was, I added one well per section -- over -- This is above the current wells in there. One well per section, two wells per section, three wells and four wells per section.

Q. Let's turn to the displays following Exhibit 14 and have you lead us through the various forecasts and what you have concluded from those forecasts.

A. Okay, the first bullet on this is, again, I ran the four infill cases, as I just mentioned. I ran a case with just the base wells, and I forecasted just what the base -- the current wells would do. Then I started adding in increased-density wells, again one well per section, two wells per section, three wells per section and four wells per section. And in every case I assumed some compression would happen on the lines out there, and it would occur in about ten-year increments.

Q. So all those assumptions on pressure compression are going to be consistent with all the model runs?

A. Yes, because in every case, what I'm doing is, I'm comparing one of the infill cases to the base case, and they were all run with the same pressure profile.

Q. Let's take the base case and run it with the first assumption of a fifth well in the section. How did you decide where to put the fifth well in the model?

A. What I did is, I physically -- for the first one, I looked at the -- where the current wells were located, and I placed the well the furthest distance from them. That was in the center of the unit. So -- in this -- or in the center of the section, I should say, I'm sorry.

So in this first case for just one per section, the wells are physically in the center of the section.

Q. Okay, so we've got a four-section model area?

A. Uh-huh.

Q. And so the first run after the base case is to add one more well per section, so you've added four wells to the model. Each additional well is located at its optimum position within the section, being the farthest point from any existing well?

A. That's correct.

Q. Historically, tell us how generally the Mesaverde wells have been located in their spacing units in a section?

A. Where there are no topographical problems, they're generally located about the minimum distance from the section lines, the minimum offset. So you get them basically around -- kind of around the corners of the unit.

Q. And so when you examine the opportunity for the first increased density well, that opportunity lies more centrally located within the section?

A. Yes.

Q. And so that's where you chose to put the first well?

A. In this particular run, yes.

Q. All right. What do you do in the next run where you've added two wells on top of the base case of four?

A. Okay, the first thing I did was, I placed them, again, in an optimum distance from the existing wells. I then ran the model, and I looked at what they call an arrow plot in the model. And what the arrow plot does is, at any given point in time it will tell you which direction a gas molecule is moving. It's kind of funny, but what you can eventually see is where the no-flow boundaries are in the model.

In other words, one -- the gas molecule is -- one gas molecule is moving this way and the other gas molecule is moving the other way. So you put a well right there, because that's basically the no-flow boundary between the wells.

Q. And you chose to use that methodology as you continued to add wells to the model, up to a maximum of four additional wells per section -- I'm sorry, a total of four -- yeah, four additional wells per section?

A. What I did on the four-additional-wells-per-section case was, I followed the -- what is considered the norm for an 80-acre infill well. I took what would be the norm for that and physically put the wells there.

Q. Show us what the model forecasted under those various cases.

A. Okay. In the next display what you're seeing is the gas production forecast. The black line on the bottom are the current wells. You will see -- You see bumps in production, three bumps in production, as you go down the plot. Again, that's from the effect of compression coming on, the three different compression cases.

The green line is where we've got a one-well-per-section and you see a nice increase in production from that.

The -- I guess that's a light-blue line, is two wells per section. Again, you see a nice increase in production.

And then for the three and four wells per section you see some increased production, but not a lot.

Q. Have you compared the forecast to anything other than gas production?

A. Yes, on the next plot you'll see cumulative -- gas cumulative forecast, and this is a forecast out about 50 years from the current time, and remembering that some of these wells in this model are over 43 years old, you're getting quite a long life on some of these wells.

What we see here is, again, we see your base case in black, and your one well per section you're seeing a nice increase in cumulative production, two wells per section you're seeing a good jump in cumulative production. And then again when you get to the three and four, you don't see much additional production from those third and fourth wells in this model.

Q. Have you also run the forecast to predict what will happen with pressure?

A. Yes, in the next display you'll see the effect on reservoir pressure with the added wells. And as you could see, again you've got the one-well-per-section, two-well-per-section, giving you a nice slice -- or giving you a nice decrease in reservoir pressure, indicating again that you produce more gas.

And I don't have the three-wells-per-section line on here because it kind of just gets blurred in between the two and the four. But you can see when you go from two to four on this particular plot that you don't -- you get some drop in reservoir pressure, but not a lot.

Q. Can you estimate for the Examiner that portion of the additional gas recovery that is simply rate acceleration and compare that to what is an increase in ultimate gas production from the section?

A. Yes. Yes, what I did I had the model -- from these plots -- I skipped a little step. I looked at -- if you look at the next slide or the next display --

Q. Oh, you put a value into it, all right. We know we can get some more gas out; now can we afford to get it?

A. Yes, and that's where I did some economics. This is looking at the present value ratio of the wells. And as you can see, as you would expect from looking at your cumulative reduction plots where that third and fourth well gets you a little bit extra but not a lot for additional costs, that the maximum number -- the most economic number, is about two per section in this particular case.

Q. In terms of the Application for the Examiner, then, we would like the flexibility in the unit to have the opportunity for you as the operator to choose a well density up to four more?

A. That's correct. This is very specific for this area. And as you go into other areas of the unit the answer may be different, it may be four wells per section.

Q. But for this particular unit you don't expect, based upon current data, that you would want to increase density more than four over the current four?

A. Not in this particular unit, no.

Q. All right. And it may be it's less than that?

A. That's right.

Q. Let's talk, then, about whether we've -- what portion of this is rate acceleration versus increased ultimate recovery.

A. Okay. If you look at the last slide, what you see here is based on two wells per section now. You see the first column there is what would happen if we had no infill drilling, in other words, we just continued on 160-acre spacing. And you see -- I think it's roughly about 63 BCF worth of recovery from those wells.

In the next column what you see is what effect infill has on it. And you can see in blue that's just the current 160 wells. Now, the cumulative production from those wells has gone down, even though overall production from all the wells has gone up. And that -- the amount that the blue has gone down is the acceleration piece that the infill wells would produce.

In this particular case, the infill wells would have -- or the increased density wells would have about 60 percent of their production would be reserve additions, and about 40 percent would be reserve acceleration, is the way this breaks out.

Q. The example sets up in the model, then, what level of density you're forecasting. Is this four more wells per section, or --

A. That's for two wells per section.

Q. Two wells per section above the current density?

A. Above the current density, yes.

Q. All right. And by adding the two wells, then, you're going to get about 60-percent new reserves?

A. That's correct.

Q. Sounds like a good idea, doesn't it?

A. I think it's a great idea.

Q. All right. Let's test the theory, then, and show us how you're going to do it in the field. If you'll turn to Exhibit Tab Number 4 -- I'm sorry, I've got the wrong tab. I'm looking for the -- Exhibit Tab Number 2, it's the last display in Exhibit 2. It's the one that shows us the first phase of the pilot area.

Are these proposed increased-density pilot wells' location derived based upon what the computer forecast to be the optimum location within this portion of the unit?

A. For the most part, yes. There has been some minor adjustments on the 64C. It was actually above the section line from the model, but we had to move it below due to topographic and archeological reasons. It was only moved about three hundred feet, I believe, or three or four hundred feet. It wasn't moved very far.

And the 37C, I believe I had it 10 feet on the other side, into the buffer zone. So we've moved it 10 feet the other side, so it's about 20 feet away.

But for the most part, they're -- they haven't been moved significantly.

Q. This will give you an opportunity, then, to drill these wells, complete and produce them, and see how well the model actually forecasted what these wells in fact will do?

A. Yes, I'll be able to verify my model with these wells and their production.

Q. Describe for us your general strategy for the entire pilot project that we're requesting takes care of the entire unit.

A. The strategy would be to drill these eight wells, as Linda had mentioned, in -- probably as soon as we had lifted -- wintering in April, we'll go out there and drill these wells, complete them and start getting production by mid-year of next year.

We will then monitor their production out of these wells. We will also monitor the production out of the offsetting wells and see if there is interference occurring.

After monitoring these wells and studying them for a period of time, we would then ascertain whether they fit our model or they do not. And if they do not, we'll try to figure out why.

And if they do, we will then at that time expand the pilot project into some of the other lower-pressure-drop areas in the unit.

Q. You're still staying within this same unit, though?

A. Still staying within the 29-7 unit.

Q. Do you see any necessity for coming back to the Division for approval of each different, separate phase of the project, or whether or not this can be approved now for the entire unit?

A. I feel it could be approved for the entire unit. Additional phases, we can -- we can, you know, correspond with you and tell you why we were going to do this, report back on the success of this.

Q. Can the entire unit area be approved for the pilot project, based upon the integrity of the buffer area?

A. I certainly think so. As tight as this rock is, we -- you do not see a lot of drainage, and thieving that would go on across -- you would not have a correlative-rights problem with the units outside your buffer zone --

Q. Do you think the --

A. -- from these increased densities.

Q. Do you think the proposed buffer area, which is a half-section wide, if you will, around the inside of the unit boundary, is an adequate buffer to protect the interests of offsetting property owners?

A. Yes, I do.

Q. In this particular unit, you don't see drainage areas that would compromise this buffer area?

A. No, we have not seen drainage areas exceeding, oh, about a hundred and -- right around a hundred acres, was the average.

So on the whole, we do not see drainage areas that would exceed -- go into the other units.

Q. If you were to take this concept and apply it to one of the other federal units you operate, you might have to specifically tune the rules and regulations for that pilot project, using different-size buffers and well locations?

A. That's correct. What we're seeing is that it's a very heterogeneous system, and every area is going to be different.

Q. Give us a forecast. There are a number of federal units in the San Juan Basin. Ms. Donohue showed us a number of them on her exhibit following Exhibit 2.

If you're successful in the 27 and 7, have we now created a system or a procedure that we can lift this process and apply it to another part of the Mesaverde and increase ultimate recovery from that pool?

A. Yes, I feel our techniques are sound, and we will be studying other units this coming year with the hope of trying to establish a few more pilot projects to collect the data necessary to really understand, to prove up our models across the Basin.

Because, as I said, it's very heterogeneous from one area to the other, and while my simulation on this shows that two wells per section was adequate, as you go down south it may in fact be you need quite a bit more wells as the reservoir quality diminishes down to the south of the Basin.

Q. One of the items we've requested is flexibility in the unit to locate wells within 10 feet of a tract boundary line. Is that a useful flexibility for you as you begin to look for specific places to put these increased-density wells?

A. Yes, that means I can -- I'll be able to place the wells within about 20 feet of what the simulator would show would be an optimum condition. So yes, very much so.

Q. Summarize for us the project and what you're trying to do with this project.

A. Well, in summary, the reason that the company allocated myself and Bill to study this so in depth is that we want to determine whether we're adequately draining our reserves. The Mesaverde formation in the San Juan Formation is a large part of our company's asset, and we want to ensure that we get adequate drainage in all of the areas.

And what the summary has shown is that in some areas we are adequately draining, and other areas we do have waste.

Q. Would approval of the pilot project for this unit provide you an opportunity to recover gas that might not otherwise be produced?

A. Yes.

Q. And may we do so in a manner, in a fashion that doesn't violate correlative rights?

A. Yes.

MR. KELLAHIN: That concludes my examination of Mr. Hesketh.

We move the introduction of his Exhibits 12, 13 and 14.

EXAMINER CATANACH: Exhibits 12, 13 and 14 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Hesketh, can you tell me, does the simulator actually pick the optimum well location, or do you input that data?

A. No, I have to input. I have to look at -- As I mentioned, the first pass through is just to get farthest away from the existing wells.

And then like I mentioned, you go into the simulator and physically look at where it's predicting. One gas molecule will go this way and the other one will go the other way, in other words, where a no-flow boundary has been established. And then you would put a well there.

Q. So these well locations that you've staked were based on -- Those were all in areas where the no-flow boundary is?

A. Yes. Which corresponds pretty well to -- if you just took a ruler and measured distance between the wells, it correlates reasonably well to that.

Q. Well, say in Section 1, certainly there was a no-flow boundary that's located somewhere other than the southwest quarter. How did you determine to locate both those wells in the southwest quarter?

A. Keeping in mind that we wanted the buffer-zone concept, we had that to start with, that we didn't want -- that we wanted to have a buffer zone to -- so we wouldn't get into any issues about correlative rights. And that limited me in Section 1 to the southwest quarter, in that section.

Q. Are you able to calculate and map drainage areas for the existing wells?

A. Using the gas-in-place calculations and using the estimated recovery factor, or the estimated ultimate reserves, you can get to a drainage area.

What we did is, we -- This is where I got confused earlier. What we did is, we took 80 percent of the original gas in place, assuming that you'd never recover 20 percent, that you'll never get reservoir pressure down to zero.

We then took that gas in place per acre, 80 percent of the original gas in place per acre, divided that into estimated recovery, and you get acres.

Now, what you get is a number of acres. What you do not get is directionality to that -- whether it's an ellipse or a circle.

Q. In picking your well locations, you've also got some geology that was input into the simulator; is that correct?

A. That's correct. We used -- Bill just showed you the results of the Menefee geostatistical model. But that was also done on the Point Lookout and Cliff House, so it was all -- The geologic model was built through the use of geostatistics on all layers.

Q. So these well locations may represent areas where the sandbodies are not continuous to the other wells; is that fair to say?

A. Yes. And again, the Menefee being very discontinuous, you probably will not penetrate all the sandbodies even with these wells but will get a significant portion of them.

Q. So utilizing your simulation, you come to the conclusion that these proposed well locations are the best locations in these four sections to optimize your recovery; is that fair?

A. Yes, to economically optimize my recovery.

Q. Is it -- Do you see that you may in fact drill more than two wells per section?

A. The data may show that. With time the data may show that. And that would -- you know, I'd -- If you drill these wells and with time you do not see an interference with the existing wells, that may point us to the fact that we could have some additional wells on there.

Again, we'd have to look at recovery from these existing wells -- or from the new wells. We'd have to estimate recovery and see how much we've improved our recovery factor in the area.

Q. Have you determined where phase two within the unit might be?

A. Phase two, my initial guess, would be down in the southwestern part of the unit. Well, there would probably be a few components to it.

Again, you see a low -- We're dealing with phase one in this area of the unit, very low pressure drop. You see a low pressure drop over here and also down here. So these would be right now my choices for a phase two.

Additional phases, you'd start testing the concept going closer to this higher drainage area, knowing that these wells would be more risky as far as whether you'd recover any reserves or not.

Q. And it's your understanding that at this point in time you're not asking for any increased allowable for this project?

A. That's my understanding, yes.

Q. But you may be back in?

A. Yes.

Q. I believe you said that your average drainage area was about 100 acres?

A. Yes, based on the way we talked about it, and -- It changes, but in the area it was about 100, is what we saw.

Q. Is that in the simulation area?

A. That was in the simulation area and, for the most part, through the unit, although it goes up and down. That's a pretty rough average.

Q. On the last page of your exhibit book you've got the two infill wells per section, EUR. Now, as I understand it, with the existing wells you're going to recover about 63 BCF?

A. Yes.

Q. Now, this is the simulation area, right?

A. Yes --

Q. Talking about --

A. -- this is just for the simulation area.

Q. Okay. With drilling two infill wells per section, you're going to recover approximately -- what? 74 --

A. Yes.

Q. -- BCF?

A. Yes, about 11 BCF additional.

Q. Okay. How are you going to tell initially, when these wells are drilled, whether or not you may have a successful project?

A. It's going to be a little difficult to tell right off the bat. We will need to get production data from them. So it will take some time before we can tell if we're successful.

Interference -- In a tight reservoir like this, interference does not occur overnight. We're talking not on the order of months; we're talking probably on the order of a year, a year plus, a year to two years, before we can tell whether or not we've been truly successful.

Q. So you're going to do some interference testing?

A. Currently we're planning on looking at just production. When I mean interference, I mean you see the interference on the production.

For instance, my simulator, when I look at the effect on interference on the -- on an offsetting well from an infill well, it may be that 10 MCF a day in the first year -- which is very difficult to spot on a production plot. I mean, the wells swing more than that due to line pressure. So you have to wait a few years before that -- That will increase with time, and it plateaus out.

According to the simulator, it plateau'd out after about four years, the interference, how much basically gas you're taking to the new well, and it plateau'd out. But it increased for the first four years, and then it plateau'd out.

Q. So about how long before you start getting some good indications?

A. Like I mentioned, it will be a year-plus.

Q. Now, you're not going to wait that amount of time between phase one and phase two, necessarily, are you?

A. Unless the information dictates otherwise, yes.

Q. You probably will?

A. Yes. Now, the information -- You know, it may surprise us all. It may be the initial shut-in pressure on the wells we drilled is going to be a lot higher than we predicted in that area, in which case, you know, you may get an initial indication that, you know, we've tapped into some virgin reservoir, some virgin Menefee channels.

Q. So I assume it would probably be a while before you came in for other units, do you think?

A. Other units -- One of our goals is to sometime next year come back with some other units that we've studied. So we will be back next year to try to get to hearing. By that time, we'll at least have the wells drilled and going.

But I think in some of the other units we're going to probably go down to some of the areas where the wells aren't so prolific.

This in a -- The 29 and 7 Unit is a reasonable area for the Mesaverde. The wells are pretty good wells; they're 3- to 4-BCF wells. They're not the great 10- to 20-BCF wells.

But down south, as you go down south, you get wells that are closer to 1 BCF, but there's still plenty of gas in place. And that's where I showed you in my pie chart you're down around 20-percent recovery factor. So those areas, we know we can drill a lot more 1-BCF wells down in that area. The question is whether that's an economic well.

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

Is there anything further?

MR. KELLAHIN: That completes our presentation in this case.

EXAMINER CATANACH: All right, there being nothing further in this case, Case 11,625 will be taken under advisement.

(Thereupon, these proceedings were concluded at 11:40 a.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11625, heard by me on October 17 1996.
David R. Catanach, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL October 20th, 1996.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998