

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 ) CASE NO. 12,508  
AND GAS COMPANY FOR APPROVAL OF A PILOT )  
PROJECT INCLUDING UNORTHODOX WELL )  
LOCATIONS AND AN EXCEPTION FROM THE )  
SPECIAL RULES AND REGULATIONS FOR THE )  
BASIN-DAKOTA GAS POOL FOR PURPOSES OF )  
ESTABLISHING A PILOT INFILL DRILLING )  
PROGRAM WITHIN ITS SAN JUAN 27-5 UNIT, )  
CONSISTING OF TOWNSHIP 27 NORTH, RANGE )  
5 WEST, WHEREBY UP TO FOUR WELLS MAY BE )  
DRILLED ON A STANDARD GAS PRORATION UNIT )  
TO DETERMINE PROPER WELL DENSITY FOR )  
DAKOTA WELLS, RIO ARriba COUNTY, )  
NEW MEXICO )

APPLICATION OF BURLINGTON RESOURCES OIL ) CASE NO. 12,509  
AND GAS COMPANY FOR APPROVAL OF A PILOT )  
PROJECT INCLUDING UNORTHODOX WELL )  
LOCATIONS AND AN EXCEPTION FROM THE )  
SPECIAL RULES AND REGULATIONS FOR THE )  
BASIN-DAKOTA GAS POOL FOR PURPOSES OF )  
ESTABLISHING A PILOT INFILL DRILLING )  
PROGRAM WITHIN ITS CULPEPPER MARTIN )  
PROJECT AREA, CONSISTING OF SECTIONS )  
1-3, 10-15 AND 22-24 TOWNSHIP 31 NORTH, )  
RANGE 12 WEST, WHEREBY UP TO FOUR WELLS )  
MAY BE DRILLED ON A STANDARD GAS )  
PRORATION UNIT TO DETERMINE PROPER WELL )  
DENSITY FOR DAKOTA WELLS, )  
SAN JUAN COUNTY, NEW MEXICO )

(Consolidated)

REPORTER'S TRANSCRIPT OF PROCEEDINGS  
EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

October 19th, 2000  
Santa Fe, New Mexico

\* \* \*

STEVEN T. BRENNER, CCR  
(505) 989-9317

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner on Thursday, October 19th, 2000, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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# I N D E X

October 19th, 2000  
Examiner Hearing  
CASE NOS. 12,508 and 12,509 (Consolidated)

	PAGE
EXHIBITS	4
APPEARANCES	5
OPENING STATEMENT BY MR. KELLAHIN	9
APPLICANT'S WITNESSES:	
<u>LINDA DEAN</u> (Landman)	
Direct Examination by Mr. Kellahin	12
Examination by Examiner Catanach	27
Examination by Mr. Chavez	36

(Continued...)

## APPLICANT'S WITNESSES (Continued):

WILLIAM BABCOCK (Geologist)

Direct Examination by Mr. Kellahin	38
Examination by Mr. Chavez	63
Examination by Examiner Catanach	72
Further Examination by Mr. Chavez	78

JACK KEAN (Engineer)

Direct Examination by Mr. Kellahin	83
Examination by Mr. Chavez	96
Examination by Examiner Catanach	100
Further Examination by Mr. Kellahin	100
Further Examination by Examiner Catanach	101

CRAIG McCracken (Engineer)

Direct Examination by Mr. Kellahin	102
Examination by Mr. Chavez	115
Examination by Examiner Catanach	119
Further Examination by Mr. Chavez	120

STATEMENT BY WAYNE TOWNSEND, BLM	125
----------------------------------	-----

STATEMENT BY RUBEN SANCHEZ, BLM	127
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STATEMENT BY BILL HAWKINS, BP AMOCO	129
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REPORTER'S CERTIFICATE	132
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## E X H I B I T S

Applicant's (Case 12,508)	Identified	Admitted
Exhibit 1	14	27
Exhibit 2	14	27
Exhibit 3	-	27
Exhibit 4	40, 86	63
Exhibit 5	54	63
Exhibit 6	54	63
Exhibit 7	84	96
Exhibit 8	88	96
Exhibit 9	104	115

Applicant's (Case 12,509)	Identified	Admitted
Exhibit 1	18	27
Exhibit 2	19	27
Exhibit 3	22	27
Exhibit 4	40	63
Exhibit 5	62	63
Exhibit 6	63	63
Exhibit 7	90	96
Exhibit 8	90	96
Exhibit 9	112	115

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## A P P E A R A N C E S

## FOR THE APPLICANT:

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By: WILLIAM F. CARR

## FOR WILLIAMS PRODUCTION COMPANY:

SUE GRIFFIN  
Counsel, Williams Production Co.  
Tulsa, Oklahoma

## ALSO PRESENT:

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

WAYNE TOWNSEND  
and  
RUBEN SANCHEZ  
Bureau of Land Management  
Farmington Field Office

MARC SHANNON  
Engineer  
Conoco, Inc.  
Houston, Texas

\* \* \*

1           WHEREUPON, the following proceedings were had at  
2   8:44 a.m.:

3           EXAMINER CATANACH: All right, at this time we'll  
4   call Case 12,508, which is the Application of Burlington  
5   Resources Oil and Gas Company for approval of a pilot  
6   project including unorthodox well locations and an  
7   exception from the special rules and regulations for the  
8   Basin-Dakota Gas Pool for purposes of establishing a pilot  
9   infill drilling program within its San Juan 27-5 Unit,  
10   consisting of Township 27 North, Range 5 West, whereby up  
11   to four wells may be drilled on a standard gas proration  
12   unit to determine proper well density for Dakota wells, Rio  
13   Arriba County, New Mexico.

14           Call for appearances in this case.

15           MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of  
16   the Santa Fe law firm of Kellahin and Kellahin, appearing  
17   on behalf of the Applicant.

18           EXAMINER CATANACH: Call for additional  
19   appearances.

20           MR. CARR: May it please the Examiner, my name is  
21   William F. Carr with the Santa Fe law firm Campbell, Carr,  
22   Berge and Sheridan. We represent BP Amoco. We are not in  
23   opposition to the Application. We do have a statement that  
24   we would like to present at the appropriate time.

25           EXAMINER CATANACH: Additional appearances?

1 MR. TOWNSEND: I'm Wayne Townsend with the Bureau  
2 of Land Management from the Farmington Field Office. We  
3 have some statements to make at the conclusion of both Case  
4 12,508 and 12,509. We have statements concerning the  
5 technical, and Mr. Ruben Sanchez will make statements  
6 concerning surface concerns.

7 EXAMINER CATANACH: Thank you, Mr. Townsend.  
8 Additional appearances?

9 MS. GRIFFIN: Sue Griffin, counsel for Williams  
10 Production Company, in support of Burlington's Application.

11 EXAMINER CATANACH: I'm sorry, Miss Griffin, on  
12 behalf of who?

13 MS. GRIFFIN: Williams Production Company.

14 EXAMINER CATANACH: Okay. Yes, sir?

15 MR. SHANNON: Yes, I'm Marc Shannon with Conoco,  
16 Houston, Texas. We're also here to support Burlington's  
17 Application.

18 EXAMINER CATANACH: Your last name, sir, is -- ?

19 MR. SHANNON: Shannon.

20 EXAMINER CATANACH: Shannon.

21 MR. SHANNON: Yes, sir.

22 EXAMINER CATANACH: Any additional appearances.

23 Okay, will the witnesses --

24 MR. KELLAHIN: May I ask you a procedural item,  
25 Mr. Examiner?

1 EXAMINER CATANACH: Yes, sir.

2 MR. KELLAHIN: We're going to try to expedite our  
3 presentation if possible, and with your permission we would  
4 like to incorporate for purposes of presentation the  
5 subsequent case, which deals with the same technical  
6 concepts. It is for a pilot area in what Burlington calls  
7 the Culpepper Martin. We believe it is possible to make a  
8 consolidated presentation. If you prefer to have them  
9 separate, we can also do that.

10 EXAMINER CATANACH: If it expedites this process,  
11 I would prefer it be consolidated, Mr. Kellahin.

12 MR. KELLAHIN: Let's consolidate it, Mr.  
13 Examiner.

14 EXAMINER CATANACH: At this time I'll call Case  
15 12,509, the Application of Burlington Resources Oil and Gas  
16 Company for approval of a pilot project including  
17 unorthodox well locations and an exception from the special  
18 rules and regulations for the Basin-Dakota Gas Pool for  
19 purposes of establishing a pilot infill drilling program  
20 within its Culpepper Martin Project Area, consisting of  
21 Sections 1-3, 10-15 and 22-24, Township 31 North, Range 12  
22 West, whereby up to four wells may be drilled on a standard  
23 gas proration unit to determine proper well density for  
24 Dakota wells, San Juan County, New Mexico.

25 Any additional appearances in either of these



1 cases?

2 MR. KELLAHIN: Without objection, then, Mr.  
3 Examiner, we recognize that the appearances made in the  
4 first case also apply to the second case.

5 We're ready to have our four witnesses sworn, Mr.  
6 Examiner.

7 EXAMINER CATANACH: Will the witnesses please  
8 stand to be sworn in?

9 (Thereupon, the witnesses were sworn.)

10 MR. KELLAHIN: Mr. Alexander, would you  
11 distribute the exhibit books, please?

12 May it please the Examiner, Mr. Examiner, we have  
13 presented to you two exhibit books. Each stands alone as  
14 to separate cases. The white binder represents the federal  
15 unit, the San Juan 27-and-5 Unit. The black binder is the  
16 Culpepper Martin area.

17 In addition, because those project area maps are  
18 8 1/2 by 11 in the exhibit book, we have provided you  
19 enlarged copies of each of those locator maps so that you  
20 would have an opportunity to more easily see how this  
21 project is organized.

22 Procedurally, for the San Juan 27-and-5 Unit,  
23 we're seeking approval to conduct a pilot project to study  
24 well density in the Basin-Dakota Gas Pool. For the  
25 27-and-5 Unit, that initial phase of study includes eight

1 wells, five of which are at unorthodox well locations.

2 In the Culpepper Martin area, that does not have  
3 the advantage of being in a federal unit. It is in what we  
4 would call a drillblock area, where all the spacing units  
5 are operated by Burlington. The Culpepper Martin area is  
6 described on the display. It deals with six wells.

7 Originally all six were at unorthodox locations. One of  
8 those has now been relocated, and so five of the six are at  
9 unorthodox locations.

10 In addition to the initial approvals, we're  
11 asking you to consider the adoption of an administrative  
12 process so that if, or when, Burlington determines they  
13 have sufficient justification for an expansion of the  
14 pilot, then we might be afforded the opportunity to submit  
15 that to the Division administratively in the absence of a  
16 hearing for consideration.

17 If you should approve the concept of the pilot,  
18 then we recognize that if future pilot wells would be at  
19 unorthodox well locations, then we would still meet the  
20 administrative filing requirements for those locations.

21 However, in this presentation we're asking you to  
22 consider the opportunity to relax some of the footage  
23 setback requirements for Dakota wells that are currently  
24 applicable in the event you see merit to relaxing those  
25 locations.

1           Generalized, the strategy is, we're taking an  
2   area that has been developed on current well density, which  
3   is one well per 160, and we're looking for opportunities to  
4   locate pilot wells. They will, out of necessity, almost  
5   always be at unorthodox well locations, because that is  
6   where the undrained portions of the reservoir lie. In  
7   order to test that well density, the wells need to be  
8   drilled to provide additional data and to further refine  
9   the reservoir simulation studies that are being conducted.

10           We have four witnesses. The first is a land  
11   expert to talk to you about the notifications, the  
12   correlative-rights issues, how we propose to address those  
13   correlative-rights issues, not only externally along the  
14   boundary, but internally concerning the location  
15   exceptions.

16           The next witness is a geologic expert who will  
17   give you several chapters on the geology. One is a general  
18   overview of the Dakota so that you can see that kind of  
19   reservoir and how it fits for purposes of this study. We  
20   will look, then, at the geology of the specific projects  
21   and take a quick glance at that. And then he'll explain  
22   his project, the concept, and justify the locations.

23           We will support that with conventional  
24   engineering information so you can see from an engineering  
25   perspective what the project is outlined to accomplish.

1           And then finally we'll follow that up with  
2   reservoir simulation presentation, to give you a  
3   demonstration of what causes us to believe that this  
4   project is appropriate at this time.

5           And with your permission, we'll call our first  
6   witness.

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

10                               DIRECT EXAMINATION

11   BY MR. KELLAHIN:

12           Q.   Would you please state your name and occupation?

13           A.   Linda Dean, land advisor with Burlington  
14   Resources Oil and Gas Company.

15           Q.   Mrs. Dean, on prior occasions have you testified  
16   before the Division?

17           A.   Yes, I have.

18           Q.   As part of your employment as a petroleum landman  
19   for Burlington, are you familiar with the issues concerning  
20   the San Juan 27-and-5 Unit?

21           A.   Yes, I have contractual and agreement knowledge  
22   relating to the federal units in the San Juan Basin.

23           Q.   In addition, is it within your control for that  
24   unit to be able to determine who are the interest owners  
25   within the unit that share in this production?

1 A. Yes, it is.

2 Q. And as part of your responsibilities, have you  
3 been engaged to provide notification to all appropriate  
4 parties?

5 A. Yes, I have notified everyone that is required.

6 Q. Let's turn to the Culpepper Martin area. Are you  
7 also familiar with that project area?

8 A. Yes, I am, with the leasehold acreage and  
9 contractual obligations.

10 Q. And to the same extent you have determined the  
11 appropriate parties to whom notice was sent, and you sent  
12 those notices?

13 A. Yes, notices have been sent.

14 Q. Let's start with the white binder that has the  
15 San Juan 27-and-5 Unit. Are you familiar with all the land  
16 exhibits in this book?

17 A. Yes, I am.

18 Q. In addition, are you familiar with the land  
19 exhibits in the Culpepper Martin area?

20 A. Yes, I am.

21 MR. KELLAHIN: Mr. Examiner, I tender Mrs. Dean  
22 as an expert petroleum landman.

23 EXAMINER CATANACH: Ms. Dean is so qualified.

24 Q. (By Mr. Kellahin) Let's identify for the record  
25 some of the first exhibit tabs, and then we'll move quickly

1 into the locator maps. If you'll look at Exhibit Tab  
2 Number 1, what is the information contained behind Exhibit  
3 Tab Number 1?

4 A. First of all, it's the application that was dated  
5 September the 22nd regarding this case, and then behind  
6 that are the owners that were notified of this Application,  
7 and then the certified receipts that have been returned.  
8 For those that did not return the receipts, we have called  
9 them and faxed them to those owners to make sure that they  
10 are aware of this Application.

11 Q. Behind Exhibit Tab Number 2, what is contained  
12 behind that tab?

13 A. The first map is just a locator map of the San  
14 Juan Basin showing the Pictured Cliffs outcrop. The  
15 Culpepper Martin area is up in this northwest quarter of  
16 the San Juan Basin, in Township 31 North, Range 12 West.  
17 And then the other pilot project area that we want to  
18 pursue is in San Juan 27-5 Unit, down about the middle of  
19 the Basin.

20 Q. If you turn past this, what is the next display?

21 A. The next display is the San Juan 27-5 Unit. It  
22 shows the boundary in green, and then all wells that have  
23 been developed to date within this unit area, with a one-  
24 section area shown around the unit.

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

1 and have you identify that.

2 A. Okay. The next one is also the same map, but it  
3 shows the outline of the current Dakota participating area,  
4 which is at the 24th expansion, effective November the 1st,  
5 1973. The Dakota pilot wells underneath this project are  
6 identified in red.

7 There is one 40-acre tract that is not in the  
8 Dakota PA, that's in Section 3. But that's the only  
9 acreage that's not included in the Dakota participating  
10 area at this time.

11 Q. The Examiner has before him a large copy of the  
12 map that you're looking at right now; is that not true?  
13 He's got --

14 A. Yes, he does.

15 Q. Let me hand one of these to you too --

16 A. Okay.

17 Q. -- so that you can see it on a better scale.

18 On this display, Mrs. Dean, explain to me what is  
19 the significance of the area just inside the outer  
20 boundary, that's got the hachmark.

21 A. That is a one-half-mile buffer zone that we have  
22 placed to protect the offset ownership outside of the San  
23 Juan 27-5 Unit.

24 Q. And what do you mean by "protect"?

25 A. Well, we want to protect correlative rights for

1 other operators for development of our pilot projects.

2 Q. It would avoid competition, then, with regards to  
3 increasing the current well density?

4 A. It shouldn't have any bearing at all, because the  
5 ownership is exactly the same, all within the unit  
6 boundary.

7 Q. And within the buffer area, then, that well  
8 density remains the same for current rules?

9 A. Yes, it does.

10 Q. And the well-location exceptions remain the same  
11 for the buffer area?

12 A. Yes, they do.

13 Q. All right, let's let me have you address yourself  
14 to the red squares that are shown on this display. What do  
15 those identify?

16 A. Those are the eight Dakota pilot infill wells  
17 that have been staked. Five of them are currently at  
18 unorthodox locations, and that's mainly due -- because of  
19 topography or fee owner request or geological reasons,  
20 which can be further explained at a later time through  
21 additional testimony.

22 Q. All right. Assume for a combination of all those  
23 reasons Burlington is advancing a request to have these  
24 locations approved. All but one of these -- I'm sorry,  
25 there's five of the eight are at unorthodox locations --



1 A. That's correct.

2 Q. -- in the federal unit?

3 A. That's correct, based upon current Dakota rules.

4 Q. All right. Are you satisfied that correlative  
5 rights will be protected concerning each of these  
6 unorthodox locations as they're applicable to the federal  
7 unit?

8 A. Yes, I do. We have actually had owner meetings  
9 with the San Juan 27-5 Unit working interest owners back on  
10 August the 29th, and we have not received any concern  
11 regarding this project at all.

12 Q. When we look at the unit documentation and how  
13 this fits together, is this a unit in which you have  
14 participating areas?

15 A. Yes, it is.

16 Q. For a participating area for the Dakota, is that  
17 area consistent with the boundaries of the federal unit,  
18 with the exception of this open 40-acre window?

19 A. Yes, it includes everything but the 40 acres, and  
20 that was due to that well being noncommercial back in 1962,  
21 which eliminated its admission into the participating area.

22 Q. Okay, and none of these locations are anywhere  
23 near that --

24 A. No.

25 Q. -- tract?

1           A.    Absolutely not.

2           Q.    Describe for the record -- I know the Examiner  
3 knows this, but describe for the record why, in your  
4 opinion, you feel correlative rights are protected within  
5 the context of the participating area in a federal unit  
6 where locations of wells are placed closer to the boundary  
7 than under current rules.

8           A.    Okay, based upon the way that the unit  
9 participating areas work in the units, all the acreage is  
10 allocated based upon leasehold ownership, divided by the  
11 total number of acres within the unit. So they're going to  
12 have a share of every well within the unit, just based upon  
13 the structure, how participating areas work throughout the  
14 unit agreement.

15          Q.    And there's no doubt in your mind that that's a  
16 definitive protection of correlative rights?

17          A.    It definitely is in this situation.

18          Q.    Let's turn to the Culpepper Martin area, and  
19 let's do that in the same fashion. If you'll take the  
20 exhibit book and start with that binder and start with  
21 Exhibit Tab Number 1, identify what is contained behind  
22 Exhibit Tab Number 1.

23          A.    Okay. First of all, it's the Application dated  
24 September the 22nd, for the Culpepper Martin area. And it  
25 has a listing of the owners that have been contacted in

1 regard to this Application, with the certified receipts  
2 behind it.

3 Again, we have contacted those owners that we  
4 didn't get evidence back that they had received and have  
5 confirmation that they do now have it. So we're confident  
6 everyone has the Application.

7 Q. Behind Exhibit Tab Number 2, identify the first  
8 display.

9 A. Again, it is the San Juan Basin locator map,  
10 which shows for this particular area the Culpepper Martin  
11 up in the northwest quarter of the Basin for Township 31  
12 North, Range 12 West, being our pilot project area that  
13 we're pursuing.

14 Q. Let's focus on that area. Do you have a display  
15 -- Well, let me ask you this.

16 Do you have the luxury of having a federal unit  
17 in the northwestern portion of the pool that could be  
18 utilized as a pilot Dakota study area?

19 A. Actually, the team did several areas of interest,  
20 trying to identify an area. We do not have any federal  
21 units up in this particular part of the Basin. So we tried  
22 to find where we had control of a majority section or area  
23 of interest to go ahead and pursue this pilot project.

24 Q. Let's look at the next display.

25 A. Okay.

1 Q. The area outlined in blue represents what?

2 A. The area outlined in blue is the location that  
3 the team has identified that we want to go ahead and pursue  
4 this density project in, mainly because we are the operator  
5 of all the gas proration units within the blue outline.

6 Q. All right. The technical team made a technical  
7 evaluation of this area --

8 A. Yes, they have.

9 Q. -- it satisfies their criteria?

10 A. It did, to qualify that it works.

11 Q. From a land perspective, this is attractive for  
12 your purposes because of what?

13 A. Because we control the operating rights of all  
14 the wells that are pilot-project wells, and we know that we  
15 have the responsibility as that operator to protect the  
16 ownership. It's there within. We have control of this  
17 area as one operator and one team monitoring all of the  
18 results from the pilot project.

19 Q. Let's turn to the next display and look at that.  
20 This next display has also been enlarged so the Examiner  
21 could follow this in a more easily readable fashion. Let  
22 me give you a copy of this one.

23 A. Okay.

24 Q. For the Culpepper Martin project area, identify  
25 for us what is the significance of the area along the

1 boundary that is within the hachmark.

2 A. We have placed a one-half mile buffer zone around  
3 our project area to protect any offset operators from our  
4 project.

5 Q. Let's look at the six red squares. Those  
6 represent what?

7 A. Those are the pilot wells that have been  
8 identified by the team that we want to do the pilot project  
9 in. And they're all interior to the half-mile buffer zone.  
10 They're all -- That's the reason this works so well, is  
11 because we actually have it interior, where we're still the  
12 operator all the way around the border of where these wells  
13 are; they're interior to it.

14 Q. As a result of those locations, then, there is no  
15 opportunity for correlative-rights impairments outside the  
16 project area, correct?

17 A. Outside the project area, that is correct.

18 Q. Among the population of initial pilot wells, in  
19 Section 14 there's one of these wells that was originally  
20 filed to be unorthodox, that now is standard. Can you  
21 describe for us which one that is?

22 A. That is correct, just as of Monday the East 7 F,  
23 which is in the west half of Section 14, has been moved to  
24 an orthodox location, so it's according to current Dakota  
25 spacing rules.

1           Q.    The technical witnesses will talk about the  
2   appropriateness of these well locations when they testify?

3           A.    That is correct.

4           Q.    But from a land perspective, is there a portion  
5   of this exhibit book that contains the topographic maps  
6   that the Examiner can reference to see why these wells fit  
7   into certain topographic solutions?

8           A.    Yes, there is. Underneath Tab 3 will be a  
9   listing or a topographical map of each location showing  
10   where they're at in relation to the drilling window.

11          Q.    Are there federal leases contained within gas  
12   proration units adjoining wells that will be proposed at  
13   unorthodox locations?

14          A.    Yes.

15          Q.    Have you met with the Bureau of Land Management  
16   concerning not only this project but with the proposal to  
17   place certain of these wells at unorthodox locations?

18          A.    Yes, we have. On October the 12th, we met with  
19   the BLM regarding potential drainage situations and have  
20   received a letter which we're willing to abide and satisfy  
21   the requirements under.

22          Q.    It has to do with the BLM standard requirements  
23   with regards to dealing with the issues of potential  
24   uncompensated drainage from wells that are at unorthodox  
25   locations?

1           A.    Yes, because there is a mixture of different  
2 types of mineral ownership within this project area.

3           Q.    In addition, there are overriding royalty owners  
4 that would have differences of position concerning those  
5 wells, are there not?

6           A.    Yes, there is.

7           Q.    And for those overriding royalty owners,  
8 Burlington is the lessee?

9           A.    Yes.

10          Q.    Or at least the current lessee --

11          A.    Yes.

12          Q.    -- that's responsible for operations?

13          A.    We control the operating rights and capabilities  
14 of responsibility relating to those overriding royalty  
15 owners.

16          Q.    From a land perspective are you satisfied that  
17 correlative rights will be adequately protected if the  
18 Division Examiner approves the unorthodox locations being  
19 requested?

20          A.    Yes, I am.

21          Q.    And why do you hold that belief?

22          A.    We see it as our responsibility as the operator  
23 of this area to protect the correlative rights, and our  
24 leasehold obligations require it, so we will monitor and  
25 make sure that if any offsetting wells are required, that

1 we will take care of that.

2 Q. All right. For example, as the common operator,  
3 then, you drill the unorthodox location, and you're  
4 crowding an offsetting spacing unit that you also operate.  
5 Because you're the common operator, will that afford  
6 Burlington the opportunity to study and determine whether  
7 you need to take action concerning the encroaching well?

8 A. Oh, definitely.

9 Q. And Culpepper Martin provides you that  
10 opportunity because you are the operator and control those  
11 leases?

12 A. Correct.

13 Q. With regards to the Division notice requirements,  
14 have you satisfied the notice requirements for obtaining  
15 approval for wells at unorthodox well locations? You have,  
16 have you not?

17 A. Yes, we have.

18 Q. Those rules do not require you to notify royalty  
19 or overriding royalty owners, do they?

20 A. Underneath Rule 1207 it does not.

21 Q. In addition to meeting with the Bureau of Land  
22 Management, have you met with any of the other regulators  
23 or government entities concerning this project?

24 A. Yes, we have. We had a meeting with the New  
25 Mexico Oil Conservation Division Aztec Office back on



1     October the 4th regarding the technical merits of this  
2     project.

3             Q.     What is your understanding of the BLM position  
4     concerning the appropriateness of the pilot project itself?

5             A.     It's my understanding they are in support of it.

6             Q.     When we look at the Culpepper -- Well, let's stay  
7     with the Culpepper Martin book, the black book.  If you  
8     turn behind Exhibit Tab Number 3 there is a drilling window  
9     display, and behind that is the specific topographic  
10    exception justification?

11            A.     Correct, correct.

12            Q.     All right.  Let's look at the drilling window map  
13    for a moment, to see if I understand what the rules are.  
14    The current rules on this display show a drilling window?

15            A.     Yes, they do.  They show a drilling window  
16    currently that is 660 feet from the quarter section line.

17            Q.     Prior to making that rule change, the prior  
18    Dakota rules afforded an opportunity to encroach on the  
19    interior 40-acre common line in the spacing unit, and that  
20    allowed you to be 130 feet, I believe, from the quarter-  
21    quarter line, was it?

22            A.     That is correct.

23            Q.     The rule was changed last year, and that area of  
24    standard location has been shrunk in that dimension, has it  
25    not?

1           A.    Yes, it has.

2           Q.    You now have to maintain a 660 setback from that  
3 interior line?

4           A.    From any quarter line.

5           Q.    Okay.  Is that what's illustrated on this  
6 display?

7           A.    Yes, it is.  It's just showing what is missing  
8 from what we previously had available to us other than, you  
9 know, moving from 790 to 660.

10          Q.    Okay, and so from a land perspective, as the  
11 technical people explore the pilot project and the location  
12 of these wells, out of necessity a large group, if not all,  
13 are going to be at locations that are not within the  
14 standard window?

15          A.    That is correct.

16          Q.    As a result of your mailings of notification to  
17 all the appropriate parties to be notified, have you  
18 received any objection?

19          A.    No, we have not.

20          Q.    As a result of your meetings with the various  
21 governmental regulators, are you aware of any objections to  
22 the pilot project?

23          A.    No, other than concerns regarding, you know,  
24 protective drainage situations, which we've addressed.

25          Q.    And that's a standard issue with regards to well

1 locations anyway, that you deal with on a regular basis?

2 A. That is correct.

3 MR. KELLAHIN: Okay. That concludes, Mr.  
4 Examiner, my questions for Mrs. Dean.

5 We would move at this time the introduction in  
6 each exhibit book of exhibit packages from 1 through.

7 EXAMINER CATANACH: 1 through 3 from each exhibit  
8 packet will be admitted as evidence.

9 Are there any questions of this witness?

10 EXAMINATION

11 BY EXAMINER CATANACH:

12 Q. Ms. Dean --

13 A. Yes, sir.

14 Q. -- the current Dakota location requirements, are  
15 those the same in the 27-5 Unit and in the Culpepper Martin  
16 area?

17 A. Based upon the recent rule changes, yes, for  
18 Dakota.

19 Q. Okay. And that is 660 feet from the outer  
20 boundary of the GPU and 10 feet from any internal quarter-  
21 quarter section line?

22 A. From the quarter-section line is where it is, not  
23 from the GPU. At one time it was the gas proration unit,  
24 and now it is at the quarter line that --

25 Q. 660 feet from the quarter-section line?

1 A. Correct.

2 Q. And 10 feet from any internal boundary?

3 A. Correct.

4 Q. And what are you proposing today? What is going  
5 to be changed by that?

6 A. In the San Juan 27-5 Unit, we're actually asking  
7 for it to match up to what the Mesaverde provides where we  
8 will protect the outer boundary of the San Juan 27-5 Unit  
9 with a 660-acre [sic] setback. It can just be 10 feet from  
10 any internal boundary. That is the way that the rules  
11 currently read in the San Juan 27-5 Unit, the Mesaverde, so  
12 that's in our Application.

13 It's different in Culpepper Martin.

14 Q. And in Culpepper Martin you're proposing what,  
15 now?

16 A. Culpepper Martin is just to extend that drilling  
17 window where it's from the gas proration unit, the 660 feet  
18 instead of the quarter line, just so we can get the middle  
19 parts available to us as being a standard location. And  
20 that would also adhere and match up and be consistent with  
21 the Mesaverde rules that are in that area.

22 Q. Okay. Within the 27-5 Unit, that 40-acre tract  
23 is not currently sharing in any Dakota production from the  
24 unit?

25 A. It's actually handled on a leasehold basis, based

1 upon what the ownership is underneath Tract 4. It was  
2 eliminated back in 1962 because it just was not as -- a  
3 prolific well as what everything else that was in the unit.

4 The acreage actually came in -- Let me think  
5 here. The west half of the southwest quarter came in  
6 underneath the initial expansion, due to geological  
7 inference. That happened back in 1953.

8 And then the northwest quarter came in underneath  
9 the first expansion due to another geological inference  
10 situation, and it wasn't until the 12th expansion that the  
11 northeast of the southwest came in.

12 So it was spaced out and it was all done based  
13 upon geological inference on how the Dakota participating  
14 area was being formed. And of course it just eliminated  
15 the 84 well when it just was not commercial enough to share  
16 in the production with the rest of the wells in the unit.

17 Q. So that 40-acre tract is not currently in a  
18 Dakota GPU?

19 A. Its in a Dakota GPU, and according to state  
20 spacing, you know, it carries its standard 320, but for  
21 production purposes it does not share in the unit  
22 participating area revenue.

23 Q. That's just paid on that --

24 A. It's paid based upon --

25 Q. -- GPU basis?

1           A.    -- that ownership in that tract for that unit.

2   And it's not that we couldn't maybe look into doing  
3   something about it. I know we've drilled the offset Dakota  
4   well, the 84 E, and possibly get it included. But, you  
5   know, it's been that way since 1962.

6           Q.    The remainder of the unit, however, is in the  
7   Dakota participating area?

8           A.    Yes, it is.

9           Q.    Which essentially means that any Dakota well  
10   drilled, production from that well is shared by all the  
11   unit interest owners?

12          A.    In like interest.

13          Q.    So drilling extra wells on these GPUs is not  
14   going to affect anybody within this unit?

15          A.    It will not.

16          Q.    How about the Culpepper Martin? I wanted to talk  
17   to you a little bit about that.

18          A.    Okay.

19          Q.    Now, as I understand it, Burlington is the  
20   operator of all of that acreage in that unit -- or in that  
21   area?

22          A.    We're the Dakota operator of everything within  
23   the project area.

24          Q.    Now, the interest is not the same, though; is  
25   that correct?

1           A.    There are some instances where the leases are  
2 consistent, that we have a mixture. We have 76 percent of  
3 this acreage being BLM minerals, 4 percent being state, and  
4 20 percent being fee. And it just depends on where you're  
5 out in the unit that it changes. The lease lines are noted  
6 on the map, it shows where it changes, you know, the lease  
7 ownership. You know, sometimes they're federal to federal,  
8 but...

9           Q.    So from proration unit to proration unit within  
10 this unit, the interests may not be common; is that  
11 correct?

12          A.    It is not, as far as the burden owners are  
13 concerned.

14          Q.    Now, if Burlington is drilling a well, say, in  
15 Section 10, which you, in fact, are, and say there's an  
16 offset GPU that's not the same interest ownership, how is  
17 that interest owner being protected in that acreage?

18          A.    Well, we're looking at doing compensating wells  
19 for that proration unit. There is one that's offsetting  
20 and stuff, and we will just have to monitor. We don't  
21 expect drainage to occur for several years, and we'll get  
22 more into that in the technical presentation. But for now  
23 it would be a concern. And we recognize that concern and  
24 are willing to protect that, you know, whatever is  
25 necessary.

1 Q. Well, simply from the fact that you're allowed to  
2 drill three wells in that half section, and I'm in the  
3 adjacent half section and I'm only allowed two wells -- I  
4 mean, how am I protected? You may eventually drill another  
5 well.

6 A. Right, right. And that's just it. We'll have to  
7 monitor it for drainage to make sure we are protecting the  
8 adjacent leasehold. And out in Section 10 that all happens  
9 to be the same lease, and so it wouldn't be a problem. But  
10 you get down in Section 14, and that's where the BLM has  
11 written their letter, because there is a mixture of federal  
12 and fee ownership within those spacing units.

13 But we don't see that right now. It's a concern  
14 that we will take the responsibility as the operator to  
15 protect those correlative rights.

16 Q. Well, I guess I'm still a little confused. If  
17 you're not ultimately allowed to drill any more wells,  
18 other than the pilot wells, I mean, I don't know how you  
19 protect --

20 A. Well, and that's what -- the reasons we were for  
21 the project area, just so we would be able to stay within  
22 there and drill, if necessary, an offsetting well. If  
23 these wells come in, you know, at high pressures and they  
24 are seen as being draining, we can go in and offset them,  
25 because we are the operator and we do control the leasehold



1 ownership that offsets them.

2 Q. So your Application is actually seeking the  
3 authority -- to have the authority to drill these  
4 additional wells?

5 A. Additional wells within this project area, if  
6 it's deemed necessary.

7 Q. Where you deem it necessary to protect  
8 correlative rights?

9 A. Correct.

10 Q. And you're going to make that determination?

11 A. I am not.

12 Q. Well, Burlington is?

13 A. A reservoir -- Burlington is.

14 MR. KELLAHIN: Well, that could be part of the  
15 administrative process that we're seeking, Mr. Examiner, so  
16 that there is Division control and review of that action.  
17 We are the common working interest owner; there is no other  
18 working interest owner. It's the royalty and overrides  
19 that are at issue.

20 THE WITNESS: Well, we do have working interest  
21 owners in Section 2 and Section 23 that have been  
22 contacted. They're not within our project wells, but they  
23 own interest, you know, in Section 2 and 23; we do have  
24 some joint owners in those two sections. And we have  
25 contacted all of them, and none of them have shown

1 objection to us going ahead with this project.

2 Q. (By Examiner Catanach) Okay. Now, who have you  
3 notified in both these cases?

4 A. We have notified all of the offset operators  
5 around the area. And if we were the operator, we notified  
6 the working interest owners that we have. And then we have  
7 notified the working interest owners that we have in  
8 Section 2 and 23, and that's it. There was 11 owners total  
9 that were contacted.

10 Q. Okay, so you've notified in this Culpepper Martin  
11 area simply the working interest owners in Sections 2 and  
12 23?

13 A. Yes.

14 Q. And the offset operators around the unit, around  
15 the proposed area?

16 A. The offset operators around the project area.

17 Q. Have you notified any royalty or overriding  
18 royalty interest owners?

19 A. No, we have not. According to Rule 1207, we  
20 currently are not required to do so.

21 Q. I see. Do you think that as a royalty interest  
22 owner, someone may be affected by this Application?

23 A. There's a possibility of it. We recognize that  
24 and are willing to protect it to the best of our ability.

25 Q. Ms. Dean, is that true also in the San Juan 27-5

1 Unit case?

2 A. We only contacted working interest owners and  
3 offset operators, that is true.

4 Q. Working interest owners.

5 A. And working interest owners where we're the  
6 operator, I should quantify that a little bit more, in the  
7 27-5 Unit.

8 Q. I'm sorry, working interest owners?

9 A. Well, if we were the operator in an offsetting  
10 proration unit --

11 Q. Uh-huh.

12 A. -- we contacted the working interest owners. A  
13 lot of it is surrounded around other federal units that we  
14 operate, and so we went ahead and contacted those that were  
15 not common to the San Juan 27-5 Unit.

16 Q. Okay. Again, no royalty interest owners or  
17 overriding royalty interest owners notified in this case?

18 A. No, sir.

19 Q. The unorthodox locations, there is going to be  
20 testimony later on about the necessity for those; is that  
21 correct?

22 A. Yes, sir.

23 Q. And the locations that you've got listed in your  
24 advertisements for these cases, those are all correct, as  
25 far as you know, right?

1           A.    Except for the East 7 after the Culpepper Martin  
2 project area, which has been just moved to a standard  
3 location and will not require an unorthodox approval.

4           Q.    Do you know what the well location is for that  
5 well?

6           A.    The current footage for it is 1510 feet from the  
7 north line, 2100 feet from the west line, Section 14,  
8 Township 31 North, Range 12 West.

9           Q.    That's the east --

10          A.    Yes, sir.

11          Q.    Have you talked to anyone that has expressed any  
12 concern about your projects?

13          A.    Other than the letter we received from the BLM  
14 regarding potential drainage, no.

15               EXAMINER CATANACH:   Okay, that's all the  
16 questions I have.

17               Mr. Chavez?

18               MR. CHAVEZ:   Mr. Examiner, Frank Chavez, Oil  
19 Conservation Division, Aztec.

20                               EXAMINATION

21 BY MR. CHAVEZ:

22          Q.    Mrs. Dean, back to the 27-5 Unit, the 40-acre  
23 nonparticipating in Section 3, is that 40 acres a single  
24 lease, a 40-acre lease?

25          A.    We actually remit royalties and pay costs on a

1 leasehold-type basis, so it really does kind of stand  
2 alone. I mean, it has a 320-acre proration unit, but the  
3 acreage does not contribute to the participating area.

4 Q. But is that 40 acres an individual lease?

5 A. Yes, it is the same, same lease.

6 Q. What is the -- Is the rest of the 320 acres of  
7 that 280 acres a separate lease?

8 A. No, it's the same lease. The whole Tract 4 is  
9 within Section 3, and it's all the same lease.

10 Q. Okay, the formula, then, for nonparticipation is  
11 only for the 40 acres that the well is located on?

12 A. Actually, in our system we show that it has a  
13 320-acre spacing unit. For state purposes it is 320 acres,  
14 but for disbursement of revenue and cost, we handle it on  
15 the leasehold basis.

16 And there's other units that this applies. You  
17 know, we've run across it as we've developed the infills  
18 and stuff where you have part of the dedicated acreage; it  
19 just has not been included because of it having a  
20 noncommercial well, just not coming in because the geology  
21 did not prove it up to come in.

22 Q. So the leasehold and working interest in that 40  
23 and in the rest of the 320 are all the same?

24 A. Yes.

25 Q. Okay.

1           A.    Yes.

2           MR. CHAVEZ:  That's all.

3           EXAMINER CATANACH:  Any further questions?

4           This witness may be excused.

5                     WILLIAM BABCOCK,

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

8                     DIRECT EXAMINATION

9   BY MR. KELLAHIN:

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

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

15          Q.   On prior occasions have you testified and  
16   qualified as an expert petroleum geologist before the  
17   Division?

18          A.   Yes, I have.

19          Q.   Has it been your responsibilities to participate  
20   on the Burlington team for this project as a petroleum  
21   geologist?

22          A.   Yes.

23          Q.   And have you studied the geology for both of the  
24   project areas?

25          A.   Yes, I have.

1 Q. In doing so, do you have a comprehensive  
2 understanding of the Basin-Dakota Gas Pool?

3 A. Yes, I do.

4 Q. As part of your presentation, do you have a  
5 portion of the exhibit book to demonstrate to the Examiner  
6 the current thinking about the Dakota Pool? And then we  
7 can be specific as to why you've chosen these two project  
8 areas. Are you able to do those kind of things?

9 A. Yes, I am.

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

12 EXAMINER CATANACH: He is so qualified.

13 Q. (By Mr. Kellahin) Let's start with the 27-5  
14 exhibit book, just so that we're looking at the same book.  
15 For all intents and purposes -- it's the white binder --  
16 are the geologic displays in each book the same, with the  
17 exception that when you got to a specific project area you  
18 duplicated in an enlarged fashion the geology for the  
19 project?

20 A. Yes, all the displays under Tab Number 4 are the  
21 same for both project areas.

22 Q. And when we get, then, to the subsequent tabs,  
23 you have made them unique as to the project?

24 A. That is correct.

25 Q. Let's start with Exhibit Tab Number 4. The

1 threshold question, I think, Mr. Babcock, is, why as a  
2 geologist are you recommending the Division approve the  
3 Culpepper Martin area and the San Juan 27-and-5 area? Is  
4 there geologic reasons that support that?

5 A. Yes, there are.

6 Q. If we look at one of these maps, what is the  
7 first, best map to look at that helps you illustrate for  
8 the Examiner those reasons? First of all for the Culpepper  
9 Martin area, why is that useful as a project area?

10 A. Several reasons why we want to test the Culpepper  
11 Martin area, which as you can see in the first map, under  
12 Exhibit Number 4, is up in the northwesternmost portion of  
13 the map area, and this is in contrast to our San Juan 27-5  
14 pilot, which is in the southeasternmost portion of the  
15 pilot area.

16 Q. When I take this map, I'm looking at what you've  
17 described as a Dakota formation EUR map?

18 A. That's correct.

19 Q. Tell me how you prepared this and what it means.

20 A. This map is where we've posted all of the  
21 individual wells within the Dakota Pool, the EUR values for  
22 those wells, which is the estimated ultimate recovery from  
23 the wells, based on decline curve analysis. We've  
24 contoured that data and created this map, and that is  
25 contoured, on an average, over about one-section grid



1 increments.

2 Q. That would be the estimated ultimate gas recovery  
3 for all wells, including the parent and the parent and the  
4 first infill?

5 A. That is correct.

6 Q. And you've displayed it on this map?

7 A. Yes, I have.

8 Q. How do I read and understand the color coding?

9 A. Okay, what this map is showing is, the contour  
10 interval lines are 1-billion-cubic-foot intervals. The  
11 contrast -- The specific values are difficult to read here,  
12 but the contrast between the blue and the green is the  
13 1-BCF contour line. So in the blue areas, the wells in  
14 that area recovered or are expected to recover somewhat  
15 less than 1 BCF. As you get into the darker greens up to  
16 the yellow, the EURs for those areas increase.

17 Q. Can you use this map in this conclusion to give  
18 us an explanation of some of your reasons why you've chosen  
19 Culpepper in the 27 and 5?

20 A. This map is an excellent place to start along  
21 that reasoning. Would you like me to pursue this?

22 Q. Yes, sir.

23 A. The basic concept of this map is, it's pretty  
24 clear that there are two large producing areas in the San  
25 Juan Basin-Dakota Pool.

1           In the southwestern portion of the pool there's a  
2   large trend with some elongated streaks coming out of that  
3   blob, and those streaks extend to the southwest.

4           In the southeasternmost portion of the map  
5   there's another large producing trend, and that trend is  
6   where two of the existing pilot areas are in, both Conoco's  
7   pilot area, which has already been approved in the San Juan  
8   28-and-7 Unit, and then the 27-and-5 Unit pilot which we  
9   are here seeking approval for.

10           The reasons for these two distinct trends in  
11   production are very obvious when you start to look at the  
12   regional geology of the Dakota.

13           Q.   Let's do that, Mr. Babcock.  If you'll take us  
14   through a summary of the regional Dakota formation geology.

15           A.   Okay.  First of all, I'd like to point out the  
16   map is the same area as the previous map.  You can see our  
17   Culpepper area pilot is outlined in the northwestern  
18   portion, and the San Juan 27-5 outline is in the  
19   southeastern portion, with the San Juan 28-and-7 Unit  
20   posted for illustration purposes.

21           Q.   This display is labeled as "2 Wells BVHH"?

22           A.   That is correct.

23           Q.   What does that mean?

24           A.   BVHH is bulk volume hydrocarbon feet.  And what  
25   that means is, you take the porosity -- take an individual

1 well within the two-wells portion -- I should back up one  
2 step.

3 The Dakota formation is composed of four  
4 formations, the Twowells, the Paguate, and then the lower  
5 and upper Cubero formations. In some cases the Cubero is  
6 combined into one unit.

7 Q. You have separate displays for each of the four  
8 intervals?

9 A. Yes, I do.

10 Q. Why have you chosen to contour on this BVHH  
11 value?

12 A. This is the primary step in getting to original  
13 gas in place in a zone. So when you break it down by the  
14 individual units within the Dakota, you can get coherent  
15 maps that make sense and also illustrate the depositional  
16 environments within that particular unit.

17 Q. Can you take each of these four maps as we go  
18 through them, identify which map you're describing, and  
19 show us a comparison between the Culpepper area and the  
20 27-and-5, so that we can visualize or illustrate the  
21 difference?

22 A. Yes, I will. Starting at the top, the Twowells  
23 is the uppermost unit within the Dakota, and it is an  
24 elongated northwest-southeast-trending shoreline sandstone.  
25 The Culpepper area is along the western edge, the

1    northwestern edge of that shoreline sandstone. The -- what  
2    we would call the net pay in that interval actually pinches  
3    out in the southwesternmost corner of our pilot area. So  
4    it is along the boundary of this Twowells unit.

5            The San Juan 27-5 pilot area in the southeastern  
6    portion of the map is in the heart of the Twowells trend.  
7    But when you get to the southeast portion, the Twowells  
8    actually has two sandstones comprising it, two different  
9    shoreline sandstones within the same unit, and our 27-5  
10   Unit is in the easternmost of those shoreline sandstones.

11           For reference again, the 28-7 Conoco pilot is in  
12   the westernmost of those two shoreline sandstones.

13           If we look at the next map, which is labeled the  
14   "Pagate BVHH", you can see that this one is dominantly in  
15   the western portion of the map area, with the greatest  
16   thickness in the southwestern portion of the map. This is  
17   a deltaic system. It does have some shoreline sandstones  
18   enclosed within it, but it appears to be a fluvial-  
19   dominated deltaic system. That's why it has some fingers,  
20   I'll call them, stretching out to the north and to the  
21   northeast, and also to the southwest. Those fingers would  
22   represent fluvial systems which are supplying sand to the  
23   shorelines.

24           This trend is -- if you can look at the main  
25   thickness trend of this Pagate system, is where that

1 southwesternmost productive trend was in the Dakota  
2 formation. This is a very thick, sand-rich interval. And  
3 this is the only -- As we go through the following maps  
4 you'll see that in the southwestern portion the Paguate is  
5 the only sand present down in that southwesternmost portion  
6 of the Basin.

7           The next map is the upper portion of the Cubero  
8 sandstone, rather limited in extent, but it's important to  
9 us in our 27-5 area because it is developed in that area.  
10 It is just marginally developed in the 28-7 area, and it is  
11 not developed at all in the Culpepper area.

12           The lowermost unit is called the "Lower Cubero  
13 BVHH" map, and this one is also a fluvial deltaic system,  
14 but it is translated to the east from where the Paguate  
15 system is, so that there is significant overlap of this  
16 system and the Twowells and the Upper Cubero system.

17           So to summarize those four maps, we have the  
18 southwesternmost portion of the area, which just has the  
19 Paguate sands present, and they are very thick in some  
20 places, which accounts for the excellent EURs. But when we  
21 move up further to the east, we see that we have overlapped  
22 Twowells, upper and lower Cubero in some places where we  
23 have all three sands present. And even in the Culpepper  
24 area we do have Paguate sands extending up into that area.

25           These maps are summarized in the following map,

1 which is original gas in place. And this is calculated by  
2 simply adding together the four previous maps and then  
3 multiplying by a  $B_g$  to convert from downhole gas in place  
4 to surface gas in place.

5 And you can see that there is some resemblance of  
6 this map to the original EUR map, which is the first one we  
7 looked at behind this tab, but that there's a significant  
8 amount of gas in place in the southeastern portion and  
9 extending up to the northwest, as well as the fluvial  
10 deltaic system to the southwest.

11 Q. Mr. Babcock, take a moment and explain for the  
12 record the color scale at the bottom left of this display.

13 A. Okay.

14 Q. How do we read this scale?

15 A. Okay, this scale is labeled at the bottom in  
16 small letters, which are difficult to see, and I've put two  
17 points on the top, which are a little easier to see. But  
18 the contact from blue to green is where we have at least 1  
19 BCF per 160-acre location present.

20 As we continue in .5-BCF contours to the right,  
21 we get up to a maximum of a little bit over 5 BCF per 160  
22 acres, which is located in 28-6, 28-7 area.

23 Q. All right, you've gone through an analysis and  
24 now have a Dakota formation original-gas-in-place map.  
25 What's the next part of your process in analyzing the pool

1 with an ultimate objective of picking project areas for the  
2 pilot? What did you do next?

3 A. Okay, since we were evaluating what is the proper  
4 well spacing in the Dakota, the most important piece of  
5 that is, where are we draining the most gas? Where are the  
6 original wells, the existing wells, adequately draining the  
7 reservoir?

8 And one way to do that is to compare EURs with  
9 gas in place. We have done that, but that will be  
10 pursued -- an engineer will be showing some more detail on  
11 that.

12 Another way to do that is simply to look at the  
13 reservoir pressures. And in the Dakota the reservoir  
14 pressures, taken at the time the well is originally  
15 drilled, are problematic because of liquid loading. So  
16 there's a limited data set that can be used for that.

17 But we feel that after the original downspacing  
18 -- No, excuse me.

19 Q. Infill drilling?

20 A. -- the original infill drilling from 320 to 160  
21 acres in the early 1980s, after that program was begun,  
22 there was a data set collected that we felt fairly  
23 confident in, which gave us this next map, which is labeled  
24 "Infill Well ISIP".

25 Now, I'd like to point out on this map that I

1 have an error on my color bar at the base of the map.

2 Q. How do we make that correction?

3 A. Just cross off the numbers at the top, the two  
4 larger numbers, 1000 p.s.i. and 2000 p.s.i. Those numbers  
5 are incorrect, they've slipped across the scale in  
6 preparing this display. The bottom numbers on this color  
7 bar are correct, so that the contact from blue to green on  
8 the left side of that color bar is 1000 p.s.i., and then  
9 the contact on the right-hand side, you can see the 1750  
10 and the 2250. It's at about 2000 pounds.

11 Q. That shift in labeling does not affect the  
12 validity of the map itself?

13 A. No, the map is still labeled correctly, and the  
14 contour values are correctly marked.

15 Q. How would you use this map to tell you anything  
16 about well density?

17 A. Well, when we -- the parent well is originally  
18 drilled and they began draining the areas, and then the  
19 increased density order, which allowed for the second well  
20 in the 320-acre drillblock, was drilled, they found a  
21 pressure. That pressure is a function of how efficiently  
22 the original well is draining that area. Lower pressures  
23 found by the second well would indicate that the original  
24 well was doing a good job of draining it. Higher pressures  
25 would indicate the original well wasn't doing as good a



1 job.

2 So in particular in this map, see, in the  
3 southwestern portion of the area where we just have one  
4 sand unit present, the Paguate trend, we can see that a lot  
5 of that area is in blue, and even less in blue, implying  
6 that back in the 1980s the second well in that drillblock  
7 found pressures less than 1000 pounds, and this is  
8 contrasted with approximately 3000 pounds that the original  
9 wells found.

10 When you move up to the northeast on this map,  
11 the colors get lighter and lighter and you get up over 2000  
12 pounds, to as much as 2500 pounds, indicating that the  
13 parent well was not doing a very good job of draining this  
14 area.

15 Q. How does this map aid you in justifying the  
16 proposal to have the Culpepper Martin project area and the  
17 27-and-5 area?

18 A. Well, in looking at increasing the density for  
19 the whole pool, we recognize that these tools are imprecise  
20 so that we would need to calibrate these tools. And so we  
21 wanted to look at a range of potential drainage situations  
22 within the pool.

23 The San Juan 28-7 pilot that Conoco has drilled  
24 is in what we would consider to be one of the better areas  
25 in the Basin for this, or one of the most poorly drained

1 areas by the parent wells. We wanted to start stepping  
2 down from that to look at other areas.

3 The San Juan 27-5 pilot seems to be a little  
4 better drained, but still with a lot of gas left in place,  
5 fairly low recovery factors.

6 And then to the Culpepper pilot area up in the  
7 northwest portion of the Basin, which is stepping down one  
8 more notch and still doesn't seem to be fully drained by  
9 the parent and first increased density well in the units --  
10 or in the drillblocks, but it seems to be an area where we  
11 can recover additional gas.

12 And so those three pilots seem to be testing a  
13 trend which is set up by the multiple sand layers which we  
14 saw from the geological maps.

15 Q. Have you studied the geologic data to determine  
16 if there is a way to compare the parent well to the infill  
17 well?

18 A. Yes, we have.

19 Q. And how have you done that?

20 A. Well, an efficient way to do that, at least in  
21 our opinion, is to compare the EUR ratios of the two wells,  
22 which is the next display, labeled "San Juan Basin Dakota  
23 Formation EUR RATIO".

24 And what this is, is simply taking the EUR of the  
25 infill well and dividing that by the EUR of the parent

1 well. So in the case of the infill well, there being no  
2 drainage by the parent well, the ratio would be -- and the  
3 infill well found the same reserves as the infill well  
4 [sic], the ratio would be one. And if the parent well  
5 drained almost all of the reserves, the ratio would be  
6 approaching zero.

7 Q. Illustrate that for me on the scale before we  
8 look at the map.

9 A. Okay.

10 Q. Can you do that on this bottom scale and describe  
11 that for me, where I am on the scale if those two events  
12 occur?

13 A. Once again, I have to apologize for this scale at  
14 the bottom. The numbers in this case, both the top and  
15 bottom numbers are incorrect, so I'll have to ask you to  
16 write in the appropriate numbers. And the beginning bar at  
17 the far left is .4 or 40 percent, the contact from green to  
18 yellow is 1, or 100 percent. So -- And then it's in  
19 increments of 20 percent. So .4, .6, .8 and then 1. And  
20 then my apologies for that.

21 Q. If I'm on the scale and I have a parent well that  
22 has been very good and has drained my spacing unit and my  
23 corresponding infill well has not been as successful, where  
24 would that put me on your color bar?

25 A. That's going to put you in the blue, or even

1 farther to the left. As we see in the southwestern portion  
2 of the Basin, we're in an area where it's actually less  
3 than 40 percent, the infill well has found less than 40  
4 percent of the reserves of the parent well.

5 That's in contrast to up to the northeast where  
6 the infill wells found as much as 100 percent of what the  
7 parent well found.

8 Q. Can you make a comparison -- You've got this  
9 comparison of the success of the infill well in relation to  
10 the parent well. Is there any way to compare or draw  
11 conclusions about how this drainage has affected your  
12 ability to effectively produce the gas in place? Could you  
13 take the gas-in-place map and compare it to the EUR-ratio  
14 map in any meaningful way? Or do they stand alone as  
15 separate displays?

16 A. If I understand your question correctly, you're  
17 asking me, is there a relationship between the OGIP map and  
18 the EUR map?

19 Q. Well, no, let me ask you this: If I have my  
20 original-gas-in-place map and I have values that show in  
21 the Conoco area and in the 27-and-5 area that there's a lot  
22 of gas in place --

23 A. Correct.

24 Q. -- and I'm looking at the EUR-ratio map, and I'm  
25 finding that the parent well has done reasonably well in

1 some of those areas, and the infill less, is there any  
2 conclusion I should draw from that map in looking back at  
3 the gas-in-place map?

4 A. Yes, the conclusion is, in those cases, that the  
5 original wells are not fully draining the drillblock area,  
6 they're not fully draining the gas that is present in those  
7 areas.

8 Q. Do you have an explanation as to why that's not  
9 occurring?

10 A. Yes, there are several reasons why that's not  
11 occurring. The most basic reason is that the individual  
12 well drainage areas are less, and the areas to the  
13 northeast that you're referring to, it's because in my  
14 opinion that we have multiple zones with significant  
15 heterogeneity in those zones, both vertically, as shown in  
16 from three to four zones in particular wellbores, and  
17 laterally, because this is not as sand-rich of an area as  
18 to the southeast.

19 Cumulatively, we have more gas in place, but  
20 they're in many more individual sandbodies in that portion  
21 of the area, and that's why you would leave gas behind.

22 Q. Describe for us what you believe will be  
23 accomplished with the two pilot projects that you can't  
24 already obtain with the existing data.

25 A. The purpose of the pilot projects is to further

1 calibrate our regional models. We believe that each of the  
2 sand zones acts as a separate reservoir across this Basin,  
3 particularly in the northeast portion of the Basin.

4 So the pilots will allow us to go into areas that  
5 we feel are the least efficiently drained in those pilots  
6 and to take reservoir pressures, determine what the  
7 existing pressure is, the average pressure of the  
8 reservoir, and also to look at zonal pressures in those  
9 areas. Those zonal pressures will allow us to more  
10 accurately calibrate our simulation models, as well as to  
11 better understand our regional gas-in-place models.

12 Q. Let's turn to the exhibit tab in the San Juan  
13 27-and-5 book. Turn behind Exhibit Tab 5 and give us a  
14 short summary of why this type log is in here.

15 A. This is simply presented as a type log to show  
16 the zones that are present in the San Juan 27-5 area. And  
17 we can see the Twowells, the Paguate and the Cubero. In  
18 this case I have not broken down the Cubero into the upper  
19 and lower Cubero formations. This type log is presented in  
20 more of a standard, industry-accepted format.

21 Q. All right. Continuing behind Exhibit Tab 6,  
22 then, what is the next exhibit?

23 A. This is a cross-section which extends across the  
24 San Juan 27-5 Unit. The cross-section line is shown on the  
25 following, the next exhibit behind this tab. But this

1 shows just the Dakota formation, and this has the Cubero  
2 formation broken up into the upper and lower Cubero, which  
3 is the nomenclature that we used in my maps previously.  
4 The previous type logs we just looked at is the third well  
5 in this cross-section, the San Juan 27-5 Unit Number 122.

6 And this shows the Twowells, Paguate, upper  
7 Cubero, which is labeled "CBRO", and then the lower Cubero,  
8 which is labeled "CBRL".

9 Q. And then following those, you've given him a  
10 structure map, an isopach map and a gas in place that is  
11 specific as to this project area?

12 A. Yes, that is correct.

13 Q. Any major geologic conclusions to draw from  
14 looking at those displays that affect his decision in this  
15 Application this morning?

16 A. No, other than that there's a lack of significant  
17 structural activity in the area, there are no major faults  
18 or significant folds in these areas that would impact  
19 drainage across the unit.

20 Q. Before we get into the specifics of why you have  
21 picked these wells and their location, summarize for me the  
22 geologic differences, if any, that separate out the  
23 27-and-5 project from Conoco's 28-and-7.

24 A. Okay. In order to do that, it's probably best,  
25 if we could, to step back to the more regional geologic

1 displays --

2 Q. Yes, sir.

3 A. -- behind Tab 4.

4 Q. Yes. Which one of those would you like us to  
5 look at?

6 A. Well, first I'd like to step through them once  
7 again. I'll try and do this quickly.

8 The Twowells, the uppermost unit, is composed of  
9 two different sand units, and you can see that in the type  
10 log, where there is two different shoreline trends, as  
11 evidenced by the coarsening upward shape to the gamma ray.  
12 But we are in the easternmost of those units, the 28-7 is  
13 in the westernmost unit. And we can skip the Paguate map  
14 because that is not present in this area and significant.  
15 It's present, but there's no sand or net pay present.

16 The upper Cubero formation, as we've defined net  
17 pay, it is not present in the 28-7 Unit, and there is a  
18 significant thickness of that in the 27-5 Unit.

19 And also, when we get into the lower Cubero, see,  
20 it is a fluvial-deltaic system. Conoco's 28-7 pilot  
21 appears to be in one channel system of that unit, and this  
22 is somewhat an amalgamation of units, but you can see the  
23 elongated northeast-southwest orientation of that yellow,  
24 extending into the 28-7 Unit.

25 In 27-5 it looks significantly different. So



1     although we're calling it the same unit, there are geologic  
2     differences.

3             Also, if we could step back to the first display  
4     behind Tab 4 that is the EUR map, "San Juan Basin Dakota  
5     Formation EUR" map, we can see that the Conoco pilot is  
6     sort of along the edges of that southeasternmost EUR --  
7     blob, I'll refer to it as -- and our San Juan 27-5 pilot is  
8     in the heart of that EUR trend. Where we see the most  
9     opportunity for economic increased density drilling is in  
10    this southeasternmost trend.

11            And we feel it's important to get a test in the  
12    center of that trend, where the EURs are a little bit  
13    higher and it's more consistently economic EURs. So we  
14    feel it is important to do another pilot area along this  
15    producing trend.

16            Q.    Let me go to the 27-and-5 pilot. You might want  
17    to use the blown-up copy of the locator map. In the  
18    27-and-5 Unit there is a request for the initial pilot  
19    wells distributed as we see on this display. Explain for  
20    me why as the initial wells you've chosen these wells in  
21    these locations.

22            A.    One of the primary considerations in choosing  
23    these wells is to maximize the undrained acreage where  
24    we're putting the wells down. And since these wells are --  
25    primary production mechanism in the Dakota formation is the

1 natural fracture system, and those natural fractures appear  
2 to be oriented in a north-south to northeast orientation,  
3 that would give you an elliptical drainage pattern oriented  
4 like that.

5 So we felt that it was important to maximize the  
6 distance in the east-west direction that we can get away  
7 from the existing wells in the area.

8 So we also had another consideration, and that  
9 was that we were constrained by where we could put the  
10 locations by existing roads. We needed to get close to  
11 existing roads because of surface-disturbance issues.

12 There were also --

13 Q. Were you able to pick this population of wells  
14 and place them in a location that satisfied you as a  
15 geologist that they were appropriate for purposes of your  
16 technical study?

17 A. Yes, we were. There were some compromises made  
18 because of topographic and archeological constraints. But  
19 in general, yes, these well locations are appropriate for  
20 this study.

21 Q. The strategy was, again, what then?

22 A. The strategy was to first optimize the location  
23 based on drainage patterns, perceived drainage patterns of  
24 the existing wells. And then after that we had to  
25 accommodate surface restrictions being very limited, new

1 surface disturbance, topographic considerations and  
2 archeological considerations on the surface.

3 Q. Why have you chosen an initial population of  
4 eight wells as opposed to some other number?

5 A. That is also a compromise. We simulated this  
6 area, and Craig will address that later but eight wells was  
7 the numbers that we used in the simulation. We felt that  
8 that was sufficient to gather enough pressure data and  
9 enough initial rate data to make us comfortable with the  
10 results from this pilot. That's our belief at this time,  
11 at least.

12 Q. Do you support the request to have an  
13 administrative procedure approvable by the Division for the  
14 addition of additional pilot wells or for an expansion of  
15 the pilot project in some fashion?

16 A. Yes, I do. We don't anticipate that we'll need  
17 more wells to evaluate our models, but there is always that  
18 possibility that we may get inconclusive results from  
19 these, so that would be the reason for seeking  
20 administrative approval for additional wells.

21 Q. All right. And you would request an  
22 administrative process that would allow you to submit that  
23 justification to the Division in an administrative format  
24 and obtain approval for an expansion subject to the  
25 specific well locations being approved?

1 A. Yes.

2 Q. Let's turn now to the Culpepper Martin area.

3 Let's look at the large display for Culpepper Martin.

4 Describe for me why the Culpepper Martin, in contrast to  
5 the 27-and-5. Why this area?

6 A. Geologically why, are you asking?

7 Q. Yes, sir.

8 A. This area is distinguished by a little higher  
9 drainage by the initial wells from the 27-5 area, so this  
10 is down on one end of what we consider to be the limit of  
11 economic development of the Dakota in an increased density.  
12 We look at this as probably more likely a commingled area,  
13 needs to be commingled with the Mesaverde in order to make  
14 this economic in most cases.

15 Q. Is part of the study team's effort to look at the  
16 opportunity for wellbores that would be economic as stand-  
17 alone Dakota wells and to also look where the Dakota is  
18 less efficiently produced, so that it is only captured by  
19 adding it in a commingled fashion with a single wellbore?  
20 Are you looking at all ranges of choices here?

21 A. Absolutely, and that is the reason for this pilot  
22 area, because we recognize that there are reserves in the  
23 Dakota that will only be recovered if we can commingle it  
24 with a higher zone to reduce our well cost.

25 Q. In the Culpepper Martin display, then, the blown-

1 up display, describe for us why you have selected with the  
2 other team members these six wells as the initial pilot  
3 wells. What do you hope to accomplish by these locations?

4 A. Once again, the criteria for choosing these well  
5 locations was the same as in the 27-5 Unit. We wanted to  
6 maximize our undrilled areas with the constraints  
7 associated with surface considerations.

8 Q. And where possible, you've attempted to locate  
9 these pilot wells at standard locations?

10 A. Yes, we have, but in most cases that was  
11 difficult to do.

12 Q. The likely location of undrained portions of the  
13 pool will often force you to an unorthodox location, from a  
14 technical perspective?

15 A. Correct.

16 Q. Were well locations that were changed for  
17 topographic or regulatory surface issues changed so far  
18 that they no longer fit your technical objectives, or do  
19 they still meet those criteria?

20 A. They still do meet those criteria. We worked  
21 closely with the surveyors in locating these wells, and the  
22 BLM, in locating these wells. Some of these locations are  
23 not my first choice, but they still meet our criteria. We  
24 wouldn't be asking for them if we didn't feel that they  
25 would suit our needs in this case.

1           Q.   Geologically, what kind of ranges of permeability  
2 are you finding in these two project areas?

3           A.   The permeability as seen in core is very low, and  
4 -- excuse me, I have to look at my notes to -- but we find  
5 -- and this is purely of the matrix -- we find  
6 permeabilities of core at bench conditions ranging from .03  
7 to .08 millidarcies. That's extremely low permeability.  
8 These are bench conditions, so they would be even lower in  
9 the subsurface.

10                   The actual permeability that our wellbores see  
11 are higher than that due to the presence of natural  
12 fractures, though.

13           Q.   Let's turn to the Culpepper Martin exhibit book,  
14 and simply for the record I'd like you to quickly go  
15 through and identify the pieces of the geologic  
16 presentation so they're clear to a reader of the transcript  
17 or to the Division Examiner.

18                   Again, if you start with Exhibit Tab Number 4 in  
19 the Culpepper Martin book, these displays are identical to  
20 the San Juan 27--and-5 book, correct?

21           A.   The Exhibit Number 4 displays are identical, yes.

22           Q.   With 5 and 6, describe for us what differences  
23 we're seeing, then, in this book for the Culpepper Martin  
24 area.

25           A.   Exhibit 5 is a type log from the Culpepper Martin

1 area, the Richardson Number 8-E well, which is located in  
2 Section 10. And that has the same format as the previous  
3 -- as the type log in the 27-5 Unit.

4 The next -- Behind Exhibit Tab 6, it once again  
5 begins with a cross-section. The third well in that cross-  
6 section is once again the same as the type log, the  
7 Richardson Number 8-E, showing the correlations in the unit  
8 in our TOPS nomenclature, which we believe is the accepted  
9 sort of industry standard in this area.

10 The next is a Twowells structure map for the  
11 area, and showing -- also showing the cross-section  
12 location.

13 The next one is the upper Dakota isopach map.

14 And then the final one is the original gas-in-  
15 place map for that area.

16 MR. KELLAHIN: Mr. Examiner, that concludes my  
17 examination of Mr. Babcock. We would move the introduction  
18 of his exhibits. They're found in each book behind Exhibit  
19 Tabs 4, 5 and 6.

20 EXAMINER CATANACH: Exhibits 4, 5 and 6 in each  
21 of the exhibit books will be admitted as evidence.

22 Questions of this witness? Mr. Chavez?

23 EXAMINATION

24 BY MR. CHAVEZ:

25 Q. Mr. Babcock, looking at the exhibit behind Tab

1 Number 2 for the well locations on the 27-5 Unit -- that's  
2 the map that also shows the buffer area -- I count 11  
3 undrilled Dakota infill locations. For example, in Section  
4 9 this map shows only three Dakota wells and an undrilled  
5 infill location in the northwest quarter. However, next  
6 door, right next to Section 8, which is fully infilled, you  
7 have two of your pilot -- those two pilot wells.

8 Was there some overriding reason why the  
9 information from the pilot well would be more important  
10 there than perhaps from the infill well in Section 9?

11 A. Once again, we're looking at a lot of these wells  
12 as commingling candidates with the Mesaverde. And I'm  
13 backing up a step to answer your question. The wells in  
14 Section 9 are -- I can't speak specifically about that  
15 well, but in general we are holding up drilling Mesaverde  
16 wells in this area in order to commingle them with the  
17 Dakota.

18 I would speculate that maybe one of the reasons  
19 for drilling that -- or for holding up that well is, it's  
20 intended to be in a location that's more suitable for the  
21 Mesaverde.

22 The reason we are drilling two wells in Section 8  
23 and the additional data we could recover from those wells  
24 is that because those wells are more truly in an increased  
25 density scenario, so to speak, with the fully developed



1 area around them, so that we felt it was necessary, if  
2 we're going to drill these wells and gather pressures to  
3 assess the validity of increasing the density to more wells  
4 than four per section, we needed to do that in sections  
5 that already had four wells in most cases.

6 It's also in an area that we simulated, and so we  
7 needed to gather additional data in the simulation area in  
8 order to further constrain our simulation, to give us more  
9 confidence of the results moving forward from here.

10 But these Dakota wells in this area are -- in  
11 general, they're marginally economic, and so that would be  
12 why there are undrilled locations such as down in Section  
13 32 and places like that.

14 Q. But you wouldn't anticipate getting the same kind  
15 of data from the Mesaverde-Dakota dual that you would from  
16 -- And these are intended right now as Dakota singles?  
17 Excuse me, let's ask that.

18 A. Yes, all of these wells will initially be drilled  
19 as Dakota stand-alones, so that we can gather pressure data  
20 and production data strictly on the Dakota with no risk of  
21 mixing up the results due to mechanical problems or  
22 whatever, if we were to complete the Mesaverde in that  
23 area.

24 Q. But there --

25 A. But that's not to rule out --

1 Q. Go ahead, I'm sorry.

2 A. That's not to rule out the possibility of  
3 commingling with the Mesaverde at a later date. In fact,  
4 it's highly likely that we would attempt to do that.

5 Q. Well, doesn't that same reasoning apply toward a  
6 well in the northwest of Section --

7 A. You probably could use that reasoning in there,  
8 yes.

9 Q. On your Tab Number 4, I'm trying to draw the  
10 relationship between your Twowells bulk volume hydrocarbon  
11 feet, that and your EUR map that precedes it.

12 A. Uh-huh.

13 Q. I was trying to draw some comparison, say, for  
14 example, in 28 and in 28-11, which show high EUR values but  
15 there's lower values -- your bulk volume hydrocarbon feet  
16 map. Is there -- How would you draw those --

17 A. Okay.

18 Q. -- significances? Why is there a difference  
19 there?

20 A. Yes.

21 Q. I guess I don't understand --

22 A. Yeah, I understand the question, I believe. I  
23 would, instead of looking at the Twowells bulk volume  
24 hydrocarbon map, I would go to the -- because in 28-10,  
25 28-11, the primary horizon present is the Paguate, which is

1 the next map.

2 So if you would look at the Paguate BVHH map, you  
3 will see that out in 28-10 we have a lot of Paguate sand.  
4 In general, it's very thick in that area. And it's also  
5 very quartz-rich, and we believe very effectively fractured  
6 in that area. And since it is one thick sand interval,  
7 that it is efficiently drained. And that's why the EURs  
8 are pretty high in that area, because you've got a thick  
9 sand that's being very efficiently drained right now.

10 Did that answer your question?

11 Q. Yes, if you go to the -- just perhaps say that  
12 generally the EUR map is perhaps a combination of the bulk  
13 volume hydrocarbon feet of the Twowells, the Paguate and  
14 the Cubero?

15 A. Absolutely, absolutely. The Twowells is  
16 important locally. If I could point out an example, if we  
17 go over to 26 and 6, you can see a yellow trend which is in  
18 the southeastern portion of the Basin, and that's a  
19 northwest-southeast-oriented high-productivity trend which  
20 corresponds extremely well with a very thick Twowells  
21 trend. So in that case there's almost a one-to-one  
22 correspondence with the Twowells thicknesses.

23 But in other areas you also have other sands  
24 which are incorporated into the original gas in place, and  
25 so the EUR map is sort of blurred by these other zones

1 coming into the picture. So you can't just look at one of  
2 the maps.

3 And also, the primary driver on EUR -- Obviously  
4 gas is important, you can only recover what's there. But  
5 one of the primary factors in any tight-gas-type scenario,  
6 particularly in the San Juan Basin, is the drainage area of  
7 the existing wells. So if the existing wells are draining  
8 a larger area, you get larger EURs.

9 Q. And they would drain larger areas because of --

10 A. Natural fracturing, increased natural fracturing.  
11 And that's a combination of both lithology and tectonic  
12 activities, which are subtle in this Basin but they  
13 certainly are present.

14 Q. Okay, so when I would compare, for example, the  
15 original gas in place contour map with the EUR map, the  
16 differences might be due to natural fracturing, why you  
17 might have more original gas in place but lower EURs, due  
18 to less fracturing?

19 A. That would be my assertion, yes. I believe that  
20 is the case.

21 Q. Okay. To your EUR ratio contour map, I was  
22 trying to understand how you explain, then, that the ratio  
23 of one to one would indicate that the infill well will  
24 recover as much as the original well. Is that --

25 A. That is correct.

1           Q.    Okay. Your conclusion that when the infill well  
2   is recovering more than the original well, you are  
3   attributing that to better what in the infill?

4           A.    Well, this color bar at the bottom is somewhat  
5   misleading, because along the edges is where we get to  
6   where the infill well recovers more than the parent well.  
7   These are isolated instances, and where you have very  
8   limited data control, contouring techniques will tend to  
9   exaggerate an isolated instance.

10                So the dark red at the top, for instance, where  
11   it's got a value of actually 4, that's one well out there  
12   where the infill well happened to tap into a very extensive  
13   natural fracture system that the parent well didn't find.

14                In the heart of the trend where it's fully  
15   developed, you do not see anything greater than one. You  
16   see up to one in the 28-7 area, and that's about it. If I  
17   understood the question correctly?

18           Q.    Well, you answered my understanding of it.

19           A.    Okay.

20           Q.    I didn't get the opportunity to look closely at  
21   the Culpepper exhibits for the wells, but is that area also  
22   -- did you look to see if there were any undrilled Dakota  
23   locations within that area?

24           A.    In that area, when you go to the west and to the  
25   north, outside of our pilot area, you get into undrilled

1 locations. But that is because the Dakota formation is  
2 thinning out there, and the EURs drop off abruptly and they  
3 become noneconomic. And that's why those are undeveloped  
4 to the west and also to the north, the northern half of 33  
5 and Section 9.

6 We feel our buffer area effectively isolates it  
7 from those locations, though.

8 Q. You testified you were going to get individual  
9 formation pressures and I guess volumes also?

10 A. Probably not from individual zones, because in  
11 order to produce these wells you have to fracture-stimulate  
12 them. And once you've done that, you've commingled the  
13 zones, the three zones, three or four zones within the  
14 Dakota.

15 But we can go in and get pressures by just  
16 perforating and breaking down the cement to access the  
17 reservoir.

18 So we'll be able to get pressures on individual  
19 zones but not rates by individual zones. We will get rates  
20 by all the commingled zones.

21 Q. So your project plan is to take individual  
22 pressures?

23 A. On some wells, yes. Not all of the pilot wells,  
24 though. We plan on getting bottomhole pressures on all of  
25 the pilot wells, individual zonal pressures on some of the

1 pilot wells.

2 Q. Do you have an idea how many is "some"? Half, a  
3 couple, one?

4 A. Yes, more than one. We haven't worked that out  
5 closely. We anticipate in the 27-5 area, probably three to  
6 four. Simulation is -- we need to -- We're going to be  
7 reworking our simulation in that area to evaluate how much  
8 we feel we really need, and also when we get up in the  
9 Culpepper area, probably less than that, more in the  
10 eastern portion of it, probably two wells in the Culpepper  
11 area.

12 Q. What would be the biggest indicate you would be  
13 looking for to call this a successful pilot?

14 A. High pressures, to sum it up. But to get more  
15 specific, I expect to -- I hope that we can find some of  
16 the zones, most likely the Cubero portion, would be at very  
17 high pressures.

18 When we take the average wellbore pressure, which  
19 is what all of our data is currently, you tend to see the  
20 lowest pressure intervals, which is the highest perm area.  
21 So by taking the zonal pressures, we hope to find that some  
22 of the zones are not being drained over 160 acres at all.  
23 And I believe that's what the results from Conoco's pilot  
24 would indicate, at least in that area.

25 We are hoping that we see similar results in

1 these areas, which appear at the surface to be more  
2 efficiently drained.

3 Q. Can you testify as to how these wells will be  
4 completed, or will somebody else be able to do that?

5 A. I'm probably not qualified to do that, but I  
6 could -- Yeah, I'm probably not qualified to do that.

7 Q. Will there be another witness that may be?

8 A. Yes, I'm sure one of them could. We'll be  
9 completing these very similar to what we've completed our  
10 other Dakota wells, though. But as far as the technical  
11 details, I'm probably not the right person to ask.

12 MR. CHAVEZ: Okay, thank you.

13 EXAMINATION

14 BY EXAMINER CATANACH:

15 Q. Mr. Babcock, what is the ultimate goal of these  
16 two pilot projects? Looking at the big picture?

17 A. Uh-huh, uh-huh. The ultimate goal, in our mind,  
18 is to be able to look across the whole San Juan Basin,  
19 where the Dakota is a producing interval and define where  
20 we can recover additional reserves of any quantity, and to  
21 also define what the economics are of recovering those  
22 additional reserves. That's the answer we're looking for,  
23 is to define that across the whole Basin. We have some  
24 models in mind, and we need to calibrate that and see if  
25 we're really correct.



1 Does that address the question?

2 Q. Well, so the ultimate goal is to maybe establish  
3 infill drilling authority Basinwide in the Dakota?

4 A. If we feel that's appropriate, yes, absolutely.

5 Q. It's kind of the same approach you've taken in  
6 the Mesaverde, which you've already accomplished; is that  
7 correct?

8 A. That is correct, we've looked at it very  
9 similarly.

10 Q. The two project areas you have proposed, in  
11 addition to the Conoco project area, do you feel that's  
12 going to be representative of the whole Basin, or does  
13 Burlington have any plans for any future pilot projects?

14 A. Right now, we feel that we've gone in and built  
15 our regional models, and we feel that between the three  
16 pilot areas that will adequately develop what we feel is  
17 going to be economic to increase the density in.

18 That's not to say that other areas may not have  
19 additional reserves present, but based on our economic  
20 criteria as we see them now, this is covering what we  
21 consider to be the full range of economics, and we think  
22 this is enough data to evaluate our models.

23 Q. So in your opinion, these three project areas are  
24 sufficiently different in terms of various geologic and  
25 recovery parameters that they are representative, or they

1 will be representative, for the whole Basin?

2 A. That is correct, that's my opinion.

3 Q. The four different producing intervals within the  
4 Dakota, do those exhibit similar permeability  
5 characteristics?

6 A. Let me first refer to the matrix permeability,  
7 which is what we determine from core. The Cubero seems to  
8 have the lowest matrix permeability and porosity. The  
9 Paguate and Twowells are somewhat variable. Based on logs,  
10 the Twowells appears to have a little bit better porosity  
11 and, I would infer, permeability, based on that, and the  
12 Paguate would be next.

13 Based on existing core data, the Paguate looks to  
14 be a little more permeable. I think that's because of the  
15 scattered distribution of core data. So I would say that  
16 there is a variation in matrix permeability from the Cubero  
17 to the Paguate, with Twowells having the highest porosity  
18 and permeability.

19 When you look at the system permeabilities,  
20 though, the Paguate trend, which is a thick, very clean,  
21 very quartz-rich sand, I believe that those attributes  
22 allow it to be more consistently fractured, and therefore  
23 its matrix permeability is probably higher. And as you  
24 remember, this is the sand trend that's in the southwestern  
25 portion of the Basin. So its system permeabilities would

1 be higher than any of the other zones.

2 The Twowells has a little bit more shale in it  
3 than any of the other zones, and therefore it's probably  
4 not quite as fractured up as the Paguate trend.

5 Sort of a convoluted answer. I hope I answered  
6 your question.

7 Q. Well, do all four zones exhibit some fracture  
8 permeability?

9 A. I believe they do, and we have to give them  
10 higher than matrix permeabilities in order to get matches  
11 based on the simulation, so that would imply that there is  
12 some fracture component.

13 Q. Is any one of these intervals the more prolific  
14 zone in this area?

15 A. In the pilot areas, it's our belief that the  
16 Twowells is the most prolific zone and that the Cubero is a  
17 secondary contributor.

18 In the Culpepper it might be a toss-up between  
19 the Twowells, and as you remember there were some fingers  
20 of the Paguate which extended up into there. There may be  
21 a toss-up between those.

22 But we feel if we can get these wells approved  
23 and get zonal pressures, that should tell us which of those  
24 is the primary contributor in that area.

25 Q. Is there any structural component to these wells'

1 drainage areas, do you think?

2 A. Personally, there may be some movement in the  
3 basement that is impacting some of the areas. I can't see  
4 it from structure. Many people have made attempts to do  
5 various things with structure maps, to try and predict  
6 where the natural fractures are in basins like this, and I  
7 have not seen any success except in extreme cases.

8 So I guess I would have to answer your question  
9 no, I don't think there is a structural component.

10 Q. Mr. Chavez asked you about some wells that have  
11 not been drilled in the 27-5 Unit, some 160-acre infill  
12 wells. I'm not sure you had an answer to that. Would you  
13 be able to submit something that addresses that question,  
14 why those wells may not have been drilled to this point and  
15 what the circumstances are?

16 A. I'm sure we can submit something. And I would  
17 agree with you, I wasn't able to give a very satisfactory  
18 answer to that question. We are in the process of drilling  
19 all of those 160-acre locations in the unit, and we've held  
20 off drilling more projects in there recently.

21 But yes, we can certainly submit some more  
22 documentation addressing that.

23 Q. The --

24 A. Excuse me, may I ask, would you be interested in  
25 a narrative describing that on --

1 Q. Sure --

2 A. -- regarding each location?

3 Q. -- that would be fine.

4 A. Okay, we can do that.

5 Q. The way that the wells were chosen within the  
6 unit, within the 27-5 Unit, the infill wells all appear to  
7 be on the west side of that unit. Is there a reason for  
8 that geologically?

9 A. There's not a geologic reason why we placed them  
10 there, other than that that is the area that -- We wanted  
11 to take the same approach that we took with the Mesaverde,  
12 which was to simulate a local area and try and characterize  
13 that area specifically and understand what kind of results  
14 we would get from that. So we felt it was important to put  
15 all of our wells in a concise area in order to calibrate a  
16 simulation, and to test interference patterns based on  
17 simulation results. And so that's why they're all grouped  
18 in one area.

19 As for why they're in that particular area,  
20 that's probably more of an arbitrary assumption. It's  
21 probably more arbitrary than anything -- We could have done  
22 it in the eastern portion of the unit as well, we just had  
23 to choose a specific area to do the study in, within the  
24 township.

25 Q. So do you think that the number of wells you've

1 chosen for each of these project areas is going to be  
2 sufficient?

3 A. That is our intent, and that's why we chose these  
4 number of wells. We chose eight here and six in the other  
5 pilot area, primarily because of the increased risk in the  
6 other pilot area, the Culpepper Martin. That's why we  
7 didn't want to step out and drill eight wells up there. We  
8 feel the economics of stand-alone wells up there are  
9 marginal.

10 We hope that eight wells will be sufficient in  
11 the 27-5 area. We felt it would be. I guess we won't  
12 really know until we get the wells in the ground and can  
13 see the results. I anticipate that these will be  
14 sufficient, though.

15 EXAMINER CATANACH: Are there any other  
16 questions?

17 FURTHER EXAMINATION

18 BY MR. CHAVEZ:

19 Q. Off that question there, for eight wells in the  
20 27-5 Unit, is there some point at which as you're drilling  
21 and getting your data you might say, Whoa, our data is such  
22 that we don't really have to drill any more wells, or that  
23 we shouldn't drill any more wells? Do you have any cutoff  
24 points like that in your plans?

25 A. Realistically, I suspect that we won't have that

1 kind of data until all eight wells are drilled, to be quite  
2 honest. But if we were to drill each well individually and  
3 take the pressures and look at the completion data, I could  
4 see conceivably where we might get to six wells and say,  
5 Well, this looks good, we might want to stop. That would  
6 be a stretch, though.

7           When we look at a naturally fractured reservoir  
8 like this, if you look at specific areas, you find a lot of  
9 variation because of the almost randomness of fractures, at  
10 least from our knowledge base. And so we want to make sure  
11 that we have a statistically significant sampling,  
12 especially in an area as important as this.

13           And so I wouldn't anticipate us stopping for any  
14 reason until we have all eight wells drilled.

15           Q. When you say statistically significant, how many  
16 wells are statistically significant in order to get --

17           A. Yes.

18           Q. -- adequate calibration of your model?

19           A. That is really a judgment decision, and it's  
20 weighed by multiple factors, not all of them technical,  
21 some of them being economic as well.

22           Q. Did you go through that process to determine how  
23 many wells would be statistically sufficient to calibrate  
24 your model?

25           A. No, not in the sense of -- We didn't do multiple

1 runs of our simulation to determine how many we needed to  
2 validate the model. I suppose there could be a technique  
3 to do that.

4 We looked at the Mesaverde analysis and saw how  
5 we did that, how many wells we drilled in each of those  
6 areas. And we were very happy with the results of the way  
7 those simulations turned out, and we felt that we had  
8 enough areal variation in our sampling of pressures and  
9 rates in order to adequately calibrate the whole model, the  
10 whole simulation area.

11 And that's really a concern, and maybe it's --  
12 You know, statistically significant, you're probably  
13 talking 20 or 30 wells in the true statistical sense of the  
14 word. So I may have used that term incorrectly. We need  
15 enough so that we are fairly comfortable with the results  
16 that we're seeing and we're comfortable that those results  
17 are representative of the unit as a whole.

18 Q. What I was getting at here was a question whether  
19 or not you might be here six months from now and  
20 requesting, We need to expand our pilot because --

21 A. Uh-huh.

22 Q. -- we didn't get enough --

23 A. Yes.

24 Q. -- data to give a good statistical model.

25 A. Uh-huh. If I understand your question correctly,



1 you're asking under what circumstances would we be here in  
2 six months?

3 Q. Well, you say the purpose was to calibrate your  
4 statistical model or your simulator?

5 A. Yes.

6 Q. And without going through the process first of  
7 how much is necessary, we wondered whether you may be  
8 actually asking for more wells than is really necessary, or  
9 too few wells at this time.

10 A. Uh-huh, okay. That's a difficult question to  
11 answer, because it really is -- It's a technical judgment  
12 call as to whether we have enough to be comfortable with  
13 our model.

14 As you know, simulation, there are -- The more  
15 data you have, the more tightly you can constrain it, the  
16 more confidence you have in that model. But at some point  
17 you have to stop and just say this is enough data.

18 We felt that eight wells was enough to do that,  
19 and clearly if we get clearly black-and-white answers, find  
20 very high pressures, original pressures in parts of the  
21 Cubero, in six out of the eight wells, we would probably  
22 feel that this is sufficient and we can be real comfortable  
23 going forward with this.

24 On the converse, if we found very low pressures  
25 in all the wells, we could probably be comfortable with

1    what we found there too. And it's when you get in that  
2    middle ground between those two extremes, which is most  
3    likely where we'll be, that we have to make a judgment call  
4    and say, Is this enough -- Are we confident with the  
5    results we're seeing? And it's very difficult for me to  
6    quantify that right now as to what kind of results and how  
7    many more wells we might need or how many less wells we  
8    might need. It's a judgment call as to how many wells we  
9    needed.

10           We felt eight is a sufficient number. We've put  
11    them all in a relatively local area so that we could  
12    constrain the size of our simulation. I guess I don't know  
13    how else to answer that question.

14           Q.    Okay, that was for 27-5 Unit. You talked about  
15    the Culpepper area as a higher risk area --

16           A.    Yes.

17           Q.    -- but it's also a smaller physical size area  
18    that you have to work in also?

19           A.    Yes.

20           Q.    So you have fewer wells there. Do the same  
21    issues apply there as we talked about with the 27-5 Unit?

22           A.    Well, they do apply there, and the reason we're  
23    looking at less wells out there is because of the risk  
24    factors, the economic risk.

25           MR. CHAVEZ: Thank you.

1 EXAMINER CATANACH: This witness may be excused.  
2 Mr. Kellahin?

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

6 DIRECT EXAMINATION

7 BY MR. KELLAHIN:

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

10 A. My name is Jack Kean. I'm a reservoir engineer  
11 for Burlington Resources.

12 Q. What portion of these exhibit books are you  
13 responsible for presenting?

14 A. I'm responsible for Exhibits 7 and 8 in both  
15 books, and the exhibits are the same in each.

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

18 A. I have not.

19 Q. Summarize for us your education.

20 A. I graduated in 1991 with a degree in petroleum  
21 engineering from Mississippi State University.

22 Q. Subsequent to graduation, summarize your  
23 employment.

24 A. I worked for Exxon Company, USA, for three years  
25 and subsequently joined Burlington Resources where I've

1 worked for the past six years.

2 Q. How do you spell your last name?

3 A. K-e-a-n.

4 Q. Okay. Mr. Kean, the participation on the  
5 Burlington team by a petroleum engineer was part of your  
6 function?

7 A. Yes, sir.

8 Q. And how long have you been on this team, studying  
9 this project?

10 A. I've been on this team studying this project for  
11 approximately eight months.

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

14 EXAMINER CATANACH: He is so qualified.

15 Q. (By Mr. Kellahin) Let me have you turn to the  
16 exhibit book for the 27-and-5 Unit. If you'll start with  
17 Tab 7, let me have you commence with -- summarize for us  
18 what you propose as Burlington's objectives for the two  
19 pilot projects.

20 A. Burlington's technical objectives are threefold:  
21 To establish the economic viability of increasing the  
22 density in certain areas of the Basin-Dakota Pool; to  
23 understand where we can economically drill Dakota tails to  
24 Mesaverde wells, because that's obviously an economic and  
25 environmentally positive approach; in addition, we would

1     like to calibrate our original gas-in-place estimates,  
2     based on data that we learn from the pilots.

3             We would also like to increase the confidence in  
4     our simulation in going forward and projecting three and  
5     four wells per GPU.

6             Q.     What are the main data requirements to achieve  
7     that objective?

8             A.     We need multi-layer bottomhole pressure in each  
9     pilot area. That will help refine the simulation. And we  
10    also would like to have, as a secondary objective, initial  
11    production rates on the increased density wells.

12            Q.     If you will flip to the next page, let's  
13    summarize for the Examiner what is essential in your  
14    opinion as a reservoir engineer to obtain those objectives.

15            A.     We would like to do the pilot programs in order  
16    to help reach our objectives. As Mr. Babcock mentioned  
17    earlier on, we plan to drill Dakota stand-alone wells, so  
18    that we do not confuse the issue with Mesaverde production,  
19    obtain that bottomhole pressure data and obtain that  
20    Dakota-only production.

21            Q.     You have been part of the team that's been  
22    responsible for picking project areas, and you've chosen  
23    the Culpepper Martin area and the 27-and-5 area. What are  
24    the reasons for those two areas?

25            A.     A couple reasons. Earlier on, Mr. Babcock showed

1 both a pressure map and a ratio map that essentially  
2 defined a trend, or a fairway, if you will, of productive  
3 areas where we might be able to economically increase the  
4 density in the Dakota.

5 Culpepper and 27-5 allow us to test two opposite  
6 ends of that fairway. In addition, we will be testing  
7 pilots that are in geologically distinct areas and areas  
8 that have, or have exhibited in the past, different  
9 production characteristics.

10 Q. Have you and the team examined the different  
11 areas of the Basin-Dakota Pool to characterize the possible  
12 range of production that defines the Dakota in this  
13 fairway?

14 A. Yes, we have.

15 Q. Describe for us where those areas are.

16 A. All-righty. We probably need to turn to the next  
17 exhibit. Its first bullet is "Areas to define the Dakota".  
18 I've listed four areas, 28-10, Culpepper Martin, 27-5 and  
19 28-7. I've placed those in order of increasing  
20 prospectiveness for increased density. That is, 27-5 and  
21 28-7 would tend to have the highest probability of  
22 successfully being able to increase the density.

23 If I could, because we have not talked about  
24 28-10 specifically yet, refer you back for a moment to  
25 Exhibit 4, the very last display, the very last display in

1 Exhibit 4. This is the ratio map that Mr. Babcock alluded  
2 to earlier on.

3 If you would, notice the location of 28-10. It  
4 is in the southwest part of the Basin, it is in area that  
5 is dominated by Paguate production. The thing that you  
6 will immediately notice is that the infill wells recovered  
7 a relatively small amount of reserves, compared to the  
8 parent wells.

9 So going forward in subsequent exhibits, I'm  
10 going to use 28-10 as a reference of an area where we don't  
11 feel the likelihood of being successful is as high as in  
12 other areas.

13 Q. Those areas would represent an opportunity to  
14 test the concept of increased density because they're  
15 likely to satisfy that criteria in terms of ultimate  
16 recovery? If the 28-and-10 area has a poor infill, the  
17 likely opportunity for increasing that density is lower,  
18 right?

19 A. That is correct.

20 Q. And as we move down the scale and look at these  
21 other three areas, conversely, the opportunity for success  
22 in a third and fourth well is increased?

23 A. That is correct.

24 Q. What are some of the reasons to increase the  
25 density that you have identified?

1           A.    There are a number of reasons to increase the  
2   density.   First is, we observed historic production  
3   increase back in the early 1980s when we went to 160-acre  
4   infill locations.

5                   We also have observed in a number of areas high  
6   recoveries by those 160-acre infills.

7                   We've also observed in the same areas relatively  
8   low recovery factors, which indicates that there's quite a  
9   bit of the resource left in the ground that perhaps  
10  increased density will allow us to recover.

11                  And finally, we have reservoir simulation results  
12  in our two pilot areas that, although preliminary, do  
13  support increasing the density.

14           Q.    Let's look at the next index tab for 8 and have  
15  you show us the comparisons of how the parent well relates  
16  to the infill well.  Let's start with the 28-and-7.  
17  Describe that relationship and what you're showing on this  
18  display.

19           A.    Yes, the graph that you see, that's labeled "28-7  
20  Parent and Offset Infill Production" on Exhibit 8, the  
21  first one, is a plot of production as a function of time  
22  from 1970 through 1999 or 2000, and it's of the 28-and-7  
23  area.

24                   The light red line is a plot of the original  
25  parent wells that were drilled on 320-acre spacing.



1           The heavy red line is the summation of those  
2     parent wells, plus the 160-acre infills that were drilled  
3     by 1985.

4           For example, the 28-7 129, an original parent  
5     well will be included in the light red line, and the 129-E  
6     will be included in the heavy red line.

7           Q.    Does this difference demonstrate that the  
8     increased density from one well per 320 to two wells per  
9     320 was appropriate?

10          A.    Yes, it really does.  There is no evidence in  
11     this production data that the 160-acre infills interfered  
12     with the parent wells.  Therefore, the incremental  
13     production that you see between those two lines is  
14     representative of additional reserves that were recovered  
15     in this period of time.

16          Q.    Is the method utilized by you the same for each  
17     of these four areas there?

18          A.    Yes, it is.

19          Q.    All right, let's thumb through those and show the  
20     Examiner the relationship.  We move to the 27-5.  What's  
21     happened here, what's the conclusion?

22          A.    I see the same conclusion, that the 160-acre  
23     infills did not interfere with the parent wells.  And I'll  
24     also point out, notice between 28-7 and 27-5 as we thumb  
25     through these, that the production today is essentially the

1 same as it was 30 years ago.

2 Q. Let's turn to the Culpepper area and look at the  
3 parent-offset relationship.

4 A. Again, I see the consistency in results that the  
5 160 acres recovered incremental reserves within this time  
6 frame.

7 Q. And then finally the 28-and-10 relationship.

8 A. This is very interesting to me. Even in 28-10,  
9 which is an area that doesn't appear to have the highest  
10 increased density potential, we see the same result, that  
11 the 160-acre infills did not interfere with the parent  
12 wells.

13 Q. Do you have at this point an explanation for  
14 that, or is that something to be investigate and decided on  
15 later?

16 A. The explanation for that is a function, most  
17 likely, of an engineering equation which is governed by  
18 reservoir pressure. Wells that saw the same pressure tend  
19 to have the same flow rates.

20 Q. You then go to the next slide here, and you have  
21 information displayed in a different relationship.  
22 Describe for us what you're doing and what conclusion you  
23 see from the display.

24 A. Yes, this is a bar graph, labeled "Infill and  
25 Parent EURs Support Increased Density". For each of the

1 areas that we just discussed, I've plotted out in red the  
2 EUR, the average EUR of the parent well, and in blue the  
3 average EUR of the infill well.

4 For example, in 28-10, you can see that the  
5 average parent well recovered about 4.5 B's, and the  
6 average infill recovered about a BCF. That's quite in  
7 contrast to the 28-and-7 area. You can see that that 160-  
8 acre infill recovered about 70 percent of what the parent  
9 produced.

10 So the conclusion that we would draw is, there's  
11 an area where there is a large difference between recovery  
12 of the parent and the recovery of the infill. That area  
13 may not be as prospective, because the parent well was  
14 relatively efficient in draining the reservoir.

15 On the other hand, in areas such as 27-5 and 28-7  
16 we've reached the opposite conclusion. And you notice that  
17 Culpepper is somewhere in between. That is one of the  
18 reasons that we feel we want to do a pilot in that area,  
19 is, we need to try to define an area like Culpepper that's  
20 not clearly one or the other.

21 Q. The next slide, would you identify and describe  
22 this one for me?

23 A. Yes, once again, a bar graph, in red representing  
24 as a percentage of original gas in place what current  
25 density will allow us to recover. In blue, we're

1 representing what we believe will not be recovered at  
2 existing density.

3           So once again, you see a similar story that we've  
4 seen earlier on. The 28-10, as you would expect, has a  
5 very high recovery factor under current density, whereas  
6 areas like 27-5 and 28-7 have relatively low recovery  
7 factors.

8           Q. Let's turn to the final display. Would you  
9 identify and describe this ratio crossplot?

10          A. Yes, the final display, the ratio crossplot,  
11 plots out the data that we've just been discussing.

12               On the Y axis, this is simply the infill-to-  
13 parent EUR ratio, the same data that we saw in the bar  
14 graph just now. On the X axis is recovery factor.

15               The first thing that you will notice is, there is  
16 a distinct trend that can be drawn through the four areas  
17 that we're discussing. And as you might expect, an area  
18 like 28-10 in the lower right-hand portion of the graph,  
19 because of its low infill-to-parent EUR, relatively high  
20 recovery factor, probably doesn't hold as much promise as  
21 some of the other areas.

22               And this also graphically demonstrates where  
23 Culpepper, once again, falls somewhat in between areas that  
24 we think have the highest potential and areas that may not  
25 hold quite as much potential.

1           This hopefully, as we gather data in our pilot  
2 wells, in our pilot locations, will allow us to validate  
3 this graph, to firm up these data points for 27-5, 28-7 and  
4 Culpepper, and hopefully going forward, allow us to use  
5 this somewhat as a coarse diagnostic tool in figuring out  
6 what areas have the highest potential for us to increase  
7 density.

8           Q.    When I see the relationship between 27-and-5 and  
9 the 28-and-7, I'm drawn to the question of why don't you  
10 just wait for Conoco to finish its pilot, rely on that as  
11 the value, then, that sets the end point of the economics?

12                   What sets the 27-and-5 apart?

13           A.    The 27-5 is distinct geologically from 28-and-7.  
14 That is the primary reason. The second reason is, two  
15 points really don't define this relationship to the degree  
16 that would make us comfortable in using this as a  
17 diagnostic tool. The addition of 27-5 greatly increases  
18 our confidence level going forward.

19           Q.    How long do you anticipate it will take  
20 Burlington once the project is approved by the Division to  
21 reach conclusions about your pilot project?

22           A.    We plan to be in a position by the end of next  
23 year to validate our existing model, modify our existing  
24 model or perhaps even, depending on what we see, reject our  
25 existing model. So by the end of next year.

1           Q.   Why have you chosen to advance the request for a  
2 pilot project now, as opposed to waiting till more or all  
3 of the Dakota infill wells that could be drilled have been  
4 drilled under current spacing?

5           A.   There really are two reasons for that.

6                   One is, we believe that certain increased density  
7 locations may offer superior economics to 160-acre  
8 locations.

9                   In addition, the Mesaverde currently has  
10 different spacing rules than the Dakota, and we are -- we  
11 would like to be able to develop the Dakota along with the  
12 Mesaverde, so that we can be as efficient as possible.

13           Q.   One of the issues the Examiner needs to address  
14 is the approval of the pilot wells that are at unorthodox  
15 location. The threshold question for him to decide is  
16 whether there is a potential drainage concern of such  
17 significant magnitude that he ought not to approve these  
18 pilot wells for you if they are not at standard locations.

19                   When we look at these wells drilled in the  
20 Dakota, what kind of rates are you anticipating, and do you  
21 have a sense for the kind of period of time it takes to see  
22 drainage, and if so, how long, and what are we describing  
23 here?

24           A.   Okay. Based on simulation work, which will be  
25 addressed later on, and also some additional modeling that

1 we've done, we expect to see initial rates in terms of  
2 average monthly production on our increased density wells  
3 in the Culpepper area probably below 200 MCF a day and in  
4 the 27-5 area possibly as high as 400 MCF a day.

5 Q. That would be the Culpepper Martin area that I  
6 would be worried about. 27-and-5 has a higher rate. We've  
7 got a unit in place to resolve any doubts about correlative  
8 rights. But if I'm in the Culpepper Martin area?

9 A. Okay, in the Culpepper Martin area, once again,  
10 probably less than 200 MCF a day. Probably we'll not begin  
11 to see material acceleration until beyond ten years.

12 Q. And there's sufficient time, then, for Burlington  
13 to react and fulfill whatever responsibilities it has as  
14 the offsetting operator to the offending well, to determine  
15 if a protection well is needed and, if so, when and how?

16 A. That is correct.

17 Q. Summarize, then, for us in conclusion, what do  
18 you anticipate as a reservoir engineer getting from the  
19 pilot project?

20 A. We should get ultimately an answer to where can  
21 we economically increase the density in the Dakota, in the  
22 Dakota fairway? We'll be able to do that by gathering the  
23 pressure and the rate data from wells that are located in  
24 increased density locations.

25 MR. KELLAHIN: That concludes my examination, Mr

1 Examiner. We move the introduction of Exhibits 7 and 8 in  
2 both of the books.

3 EXAMINER CATANACH: Exhibits 7 and 8 will be  
4 admitted as evidence.

5 Questions of the witness?

6 Mr. Chavez?

7 EXAMINATION

8 BY MR. CHAVEZ:

9 Q. Mr. Kean, is there a contradiction in your Tab 8  
10 between your 28-10 parent-offset infill graph and your  
11 volumetric recovery bar graph?

12 I was trying to listen to what you said there,  
13 and you said it was surprising that there was no impact, if  
14 I remembered your statement right, that there was  
15 apparently no impact to original production and that you  
16 were getting new gas in 28-10, while the bar graph doesn't  
17 seem to support that. Did I misunderstand you?

18 A. I'm not sure if I understand your question.

19 Q. I had understood you saying that in your graph of  
20 the 28-10 parent and offset infill production, the graph  
21 indicated that although it wasn't expected, it showed there  
22 was new gas being produced from the infill. However, your  
23 volumetric recoveries bar graph doesn't seem to support  
24 that that would be the case, or only for a very short  
25 period of time. Is that -- Am I interpreting that



1 correctly?

2 A. I believe you are. When I originally saw the  
3 28-and-10 graph I was a little surprised, because I knew  
4 that it was in an area where the parent wells seem to be  
5 relatively efficient. I thought that we might see some  
6 interference, but we did not, so that's why I was a little  
7 surprised when I saw this data for the first time.

8 Q. Did that change or cause you to question how you  
9 might be interpreting the efficiency of the parent wells  
10 and draining?

11 A. I don't think so. The simulation data that we  
12 have done does not show material acceleration until 10 to  
13 20 years into the future. What's interesting about this  
14 production data is that we have 10 to 20 years of that  
15 production data, and we evidently have not seen that  
16 material acceleration yet.

17 So in my opinion, this actual data confirms or  
18 corroborates what we see in our simulation models.

19 Q. So you would anticipate, then, perhaps, in the  
20 28-10 area sometime soon, whatever that may be, you'd see  
21 significant material acceleration then?

22 A. That is a distinct possibility, although I would  
23 temper that with the point that this area has a high degree  
24 of continuity. Average reservoir pressure is relatively  
25 the same across the area. Therefore, the wells should

1 produce at pretty similar rates.

2 If I go to the equation  $Q$ , flow rate, equals  $C$   
3 times reservoir pressure squared, minus the flowing  
4 bottomhole pressure squared, raised to the  $n$  -- In other  
5 words, what I'm saying is,  $R$  is common between the parents  
6 and the infills, therefore rates are probably going to be  
7 pretty similar between...

8 Q. In addressing those rates, did you compare well  
9 completion practices, things such as pipeline pressures in  
10 the areas or operating practices like localized compression  
11 to determine whether they may have influenced the  
12 difference in the rates that you might have seen by the  
13 different operators?

14 A. That is a very good question, because you might  
15 look at the bar graphs that we saw on EUR where a parent  
16 well recovered more than an infill, and then if the infill  
17 was completed in a different technique you might try to  
18 conclude that it was due to a difference in completion  
19 practice.

20 We did look at it and what we found is,  
21 completion fluid, that is, gel, linear gel, crosslinked  
22 versus slickwater, did not make an impact on EUR.

23 I base that assertion on looking at 1340 parent  
24 and infill wells. That was our universe of data. From  
25 that data set, we culled down to specific areas. We had

1 both slickwater completions and linear gel or crosslinked  
2 gel completions, and looked at the EURs and the rates.

3 And what we found on a parent-to-parent basis and  
4 an infill-to-infill basis, there was no meaningful  
5 difference in EUR according to completion practice.

6 Q. Do you anticipate -- or have you looked at the  
7 capacities of the gathering lines in the area to determine  
8 whether or not these increased number of wells on  
9 production may require perhaps curtailing other producing  
10 wells or shutting them in, in some way?

11 A. Right now in the Basin, there are places of  
12 curtailment.

13 There are other places where the gas is able to  
14 flow without causing additional problems to other wells.  
15 But once again, I don't see that as a material issue right  
16 now for the pilots, because the rates of the wells will be  
17 relatively low.

18 Q. But in that particular area, in the Culpepper  
19 area and in the proposed pilot area in 27-5, do you know  
20 whether there's curtailment at this time occurring there  
21 because of pipeline or gathering-line capacities?

22 A. Before I'd answer that, I'd want to double-check  
23 to make absolutely sure.

24 MR. CHAVEZ: I think that's all I have. Thank  
25 you.

## EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Kean, in the Culpepper Martin area you're anticipating 200-MCF-per-day increase in -- Or is that the initial producing rate of the infill well?

A. About the initial average monthly rate.

Q. Have you looked at -- Is there any way to estimate at this point how much of that will be new reserves and how much will be an accelerated-type situation?

A. Yes, sir, my colleague Craig McCracken will address that here a little bit with his simulation and show you that specifically.

Q. And when you talk about interference on your graphs, if these wells were exhibiting any interference you would normally see a decline in the parent producing rate?

A. Yes.

Q. And you're not seeing it?

A. Do not see it.

EXAMINER CATANACH: That's all I have. This witness may be excused.

MR. KELLAHIN: Just a point of clarification.

## FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Kean, Mr. Chavez was looking at this bar

1 graph that had the volumetric recovery. It says "Support  
2 Increased Density". Do you have that display?

3 A. Yes, sir.

4 Q. Am I correct in understanding that the red  
5 portion of the display would be the volumetric recoveries  
6 attributable to the parent well and to the infill well?

7 A. That is correct.

8 Q. So when I look at the blue portion, that's the  
9 resource that remains available for investigation as to  
10 whether it will support a density greater than two wells  
11 per 320, plus some portion that may be attributable to  
12 adding wells under the current density?

13 A. That is correct.

14 Q. But at least for Culpepper 27-and-5 and 28-and-7,  
15 the magnitude of that resource that's left after current  
16 density is enough to justify going forward with the pilot  
17 project?

18 A. Yes, it is.

19 MR. KELLAHIN: All right, thank you.

20 FURTHER EXAMINATION

21 BY EXAMINER CATANACH:

22 Q. Are the recovery factors for these reservoirs the  
23 same in these two different areas? Are you recovering the  
24 same percentage of the original gas in place?

25 A. In which two areas?

1 A. Well, the Culpepper Martin and the San Juan 27-5?

2 A. It definitely appears right now that we have a  
3 higher recovery factor in the Culpepper area than we do in  
4 the 27-5.

5 Q. And what is that range of recovery?

6 A. 27-5 is around 40-percent recovery factor, while  
7 the Culpepper area is around 65 to 70 percent, based on our  
8 existing geologic model.

9 Q. That's quite a difference. Is that all  
10 attributed to geologic factors?

11 A. I believe it is.

12 EXAMINER CATANACH: Okay, I have nothing further.

13 CRAIG McCracken,

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

16 DIRECT EXAMINATION

17 BY MR. KELLAHIN:

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

20 A. Craig McCracken, reservoir engineer, Burlington  
21 Resources.

22 Q. Mr. McCracken, on prior occasions have you  
23 testified before the Division?

24 A. I have.

25 Q. As part of your participation in the Burlington

1 team to study the project, you are contributing the  
2 reservoir-simulation aspects?

3 A. That is correct. And I should clarify, the 27-5  
4 model was prepared under my direct supervision, and Mr.  
5 Kean and I cooperated on the preparation of the Culpepper  
6 Martin model.

7 Q. All right, sir. The presentation on the  
8 simulation is yours to make for both project areas?

9 A. Yes, it is.

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

12 EXAMINER CATANACH: He is so qualified.

13 Q. (By Mr. Kellahin) Let's start with the 28-and-7  
14 model, and then as we get to it we'll show the Examiner the  
15 differences and the conclusions you've reached about  
16 Culpepper Martin. But let's start with the San Juan  
17 27-and-5 Unit.

18 First of all, describe for me the kind of model  
19 you've selected and why you did so.

20 A. The software that was used in the preparation of  
21 this model was the Eclipse software package. We chose to  
22 set this model up as a dual-porosity, dual-permeability  
23 model, where you have matrix porosity and matrix  
24 permeability, and to capture all four layers that are  
25 present in the model, in the geologic model, that is.

1 Q. Your first display after Exhibit Tab 9 simply  
2 summarized the model and the four layers?

3 A. That's correct.

4 Q. It then talks about a grid size. Why have you  
5 picked this particular grid size in this area?

6 A. It's probably illustrative to flip back two  
7 exhibits to a picture of the grid which shows that 51-by-51  
8 grid. That's only one layer of the grid, that doesn't show  
9 all four layers. It's just the first layer.

10 And what this shows is that the grid is  
11 sufficient to capture an area of a significant number of  
12 wells with significant -- I'm sorry, sufficient grid cells  
13 in between wells to allow for the calculations that the  
14 model does.

15 Q. Okay. We've got a grid that's large enough to  
16 encompass a population of 31 existing wells.

17 A. That's correct, that grid is 4800 acres, and  
18 there are 31 existing producing wells within the grid.

19 Q. Those producing wells would include the parent  
20 and the infill well where they existed within the grid  
21 area?

22 A. Yes.

23 Q. And then for modeling purposes, you're going to  
24 introduce eight more wells to the model area?

25 A. That's correct.



1           Q.    That generalizes to adding just one more well per  
2 GPU, does it not?

3           A.    Yes, it does.

4           Q.    So we're not investigating densities beyond the  
5 simulation of what may occur with adding -- having three  
6 wells producing in a GPU?

7           A.    That's right.

8           Q.    Okay.  Let's go to the simulation inputs then.  
9 If you'll turn to the next page, describe for us the input  
10 values and parameters you've used.

11          A.    The way this was done in practice was that the  
12 geological models that made up the BVHH map that you saw  
13 earlier were input directly into the simulator in digital  
14 fashion, and the simulator was then able to interpolate a  
15 value of porosity, water saturation and thickness for each  
16 of the grid cells in the reservoir model.

17               What I wanted to do here was just to give you a  
18 feel for what those parameters were by giving you an  
19 average for each of the zones.  And as the exhibit shows,  
20 for the two wells that porosity was about 10 percent on  
21 average, 40-percent water saturation, 15-foot thickness.  
22 The Paguate was 1-percent porosity, 96-percent water  
23 saturation and 1-foot thickness.  So you can see from that  
24 that that wasn't a very significant zone, which correlates  
25 to what Bill said about the Paguate in this area.

1           The Cubero was 9-percent porosity, 46-percent  
2 water saturated and 11-foot thick. And then the lower  
3 Cubero was 9-percent porosity, 20-percent water saturation  
4 and 25-foot thick.

5           I also input an initial pressure of 3085 pounds  
6 per square inch into this model for average reservoir  
7 pressure, and that was based on initial pressures from all  
8 of the parent wells averaged.

9           Q. Let me understand how you actually do this. Mr.  
10 McCracken -- Mr. Babcock would give you a digitized map of  
11 these geologic values?

12          A. That's correct.

13          Q. And they will be specific as to each well?

14          A. Yes, they will.

15          Q. You've not assumed a general value for porosity  
16 and applied that to all 31 wells?

17          A. That's correct.

18          Q. So it's unique in that it's been specifically  
19 identified per well, per layer?

20          A. Yes.

21          Q. Okay. You put in your pressure. What then do  
22 you do?

23          A. The next step is to obtain what's known as a  
24 history match, and what was varied in order to obtain this  
25 history match was essentially the operating conditions of

1 the well, the skin, which is related to how the well is  
2 completed, and the flowing bottomhole pressure, which is  
3 related to how the wells are operated from a pipeline  
4 standpoint.

5 Q. For purposes of this simulation, then, the only  
6 value you're trying to match with the simulation is  
7 production?

8 A. That's correct.

9 Q. And it's gas production?

10 A. Yes.

11 Q. And the only parameters are variables that you're  
12 adjusting to make the match are what?

13 A. Operating conditions, essentially, flowing  
14 bottomhole pressure and skin.

15 Q. All right. So you're not adjusting permeability  
16 or porosity or any of those kind of things to get your  
17 match on --

18 A. No, permeabilities were from core.

19 Q. All right, so you get your model to match the  
20 existing history of production, and how confident are you  
21 about matching this parameter with this data?

22 A. If you'll flip to the next exhibit after the  
23 simulation grid, the way we build confidence in these  
24 models is by checking how well they match what happened in  
25 actuality, and that's what I referred to earlier as the

1 history-match portion of the process.

2           And what I'm showing here is the history match on  
3 cumulative gas production versus time. The solid line  
4 represents actual data up through April of 2000, which is  
5 the date to which I did my history match. The diamonds  
6 beyond that represent a projection of just those 31 wells  
7 continuing to produce at whatever conditions they were at  
8 on April the 1st of 2000.

9           If you have pressure data in a process like this,  
10 that also represents a good check. Unfortunately, what we  
11 have for pressure data within this area is essentially the  
12 shut-in wellhead pressures of the infill wells at the time  
13 that they were drilled.

14           And the problem with shut-in wellhead pressures  
15 tends to be, if you have fluid -- and this is an area that  
16 does produce some condensate -- if you have a fluid level  
17 in the well and you don't know what it was, and you don't  
18 have any measurement of what that fluid level was, it's  
19 hard to relate a shut-in wellhead pressure to a shut-in  
20 bottomhole pressure. And in our review of our records, we  
21 had one shut-in bottomhole pressure in the San Juan 27-5  
22 Unit on an infill well, and it was outside the grid.

23           Q. You get your model calibrated, you get the match,  
24 and then it forecasts future production?

25           A. That's correct.

1 Q. All right. Now you've got a model that you can  
2 introduce your eight new infill wells?

3 A. Yes.

4 Q. And you did that?

5 A. I did.

6 Q. And then you ran your model again?

7 A. Right.

8 Q. And what did you forecast?

9 A. The next exhibit shows a forecast of the  
10 cumulative production versus time for the 39 wells, and  
11 that's the 31 wells that originally existed, plus the eight  
12 increased density wells. And that total was roughly 66 BCF  
13 over the 30-year period of time that we ran the model for.

14 What the next line down, the 59 BCF, relates to  
15 is what I'm calling the base case, and that's the  
16 projection run that matches up with the graph before where  
17 there were no increased density wells drilled. The line  
18 beneath that represents the performance of those 31 wells  
19 with the eight increased density wells drilled, and that's  
20 about 56 BCF.

21 What I'm illustrating here is that acceleration  
22 versus unique reserves component that you brought up  
23 earlier. And --

24 Q. Let's make sure we have an understanding of what  
25 you're displaying. The difference that's displayed in blue

1 represents the component of recovery attributed to rate  
2 acceleration by the introduction of the eight additional  
3 wells?

4 A. That's correct, and that's rate acceleration from  
5 the 31 existing wells to the eight new wells.

6 Q. The area in purple illustrates the additional  
7 reserves to be recovered by the eight increased density  
8 wells?

9 A. That's correct.

10 Q. And so whatever the difference is between the 66  
11 and the 59 BCF?

12 A. That's correct.

13 Q. Just short of 7 BCF?

14 A. Yes.

15 Q. Okay. What does that tell you?

16 A. If you look at it on a 30-year look like we did  
17 in this analysis, the reserves that you're going to obtain  
18 from drilling an additional eight wells in this pattern is  
19 roughly one-third acceleration and two-thirds unique  
20 reserves.

21 Q. That makes it very attractive to consider the  
22 increased density for at least the area being simulated?

23 A. I would say so.

24 Q. Let's put this in a real-world context. Have you  
25 put some values as to cost and price of your product and

1 forecast whether there's an economic potential associated  
2 to the recovery of this additional gas?

3 A. I have.

4 Q. Let's have you identify and describe what you've  
5 done and what you've concluded.

6 A. The next exhibit shows the average of the eight  
7 wells' output from the simulator. This is the rate-versus-  
8 time performance of each of those wells.

9 And this production forecast was then  
10 incorporated into an economic model with the parameters on  
11 the following page for cost, monthly operating costs, and  
12 an assumption for pricing. And the results that we  
13 obtained are on the right-hand column.

14 What this shows us is that this is a favorable  
15 project for us to pursue from an economic standpoint, and  
16 we think that it makes sense to pursue.

17 Q. What do you hope to achieve as a simulator by the  
18 Division approving the pilot projects for both areas?

19 A. As we spoke about earlier, the model right now is  
20 constrained essentially by gas production. And we would  
21 like to have a model that's constrained by gas production  
22 as well as some pressure data. And the pressure data that  
23 we're going to obtain, both in aggregate and by layer, we  
24 think will serve to constrain this model further.

25 Q. Once you have further constrained your model with

1 the additional data, will you then be able to introduce  
2 wells at increased density locations to test whether it is  
3 appropriate to have densities of four more wells in a  
4 section or two more wells in a section, that kind of  
5 forecasting study?

6 A. Yes, we will, and we will be able to have a  
7 higher degree of confidence in those forecasts, and we'll  
8 be able to sensitize other things too, such as the  
9 placement of those wells.

10 Q. Okay. Let's turn now to the Culpepper Martin  
11 simulation, and let's identify those displays for the  
12 Examiner to complete your presentation.

13 A. The set of displays under the Culpepper Martin  
14 model follows the same pattern. So if you'll allow me,  
15 I'll highlight the differences on each of these displays  
16 with the 27-and-5.

17 In Culpepper, the lower Cubero interval  
18 essentially was nonexistent. So it's a three-layer model  
19 instead of a four-layer model.

20 The Culpepper Martin area is a little bit more  
21 elongated in the north-south direction, so our grid,  
22 instead of being a square, was a little bit more  
23 rectangular, with a 47-by-38-by-3-layer grid, and it was  
24 a bit larger to incorporate all of the wells that were in  
25 the area.



1           There were six increased-density wells in the  
2 Culpepper Martin model to match up with what it is we plan  
3 to do.

4           Some differences in the simulation inputs, you'll  
5 see that some of the porosity values are fairly similar,  
6 formation by formation, although there's a major difference  
7 in the Paguate. The Paguate is a much more significant  
8 interval and a more significant contributor to production  
9 in the Culpepper Martin, and that's reflected in the  
10 parameters that go into the simulation. It's also a  
11 somewhat lower-pressure area, and that's also reflected in  
12 the simulation inputs.

13           The next page in the exhibit shows what that  
14 simulation grid looks like. It was constructed with the  
15 same general ideas in mind as the 27-5 grid.

16           The history match follows, and again the solid  
17 line is the actual, the diamonds are the model, and where  
18 the solid line ends represents the projection of the model  
19 for the next 30 years.

20           The next page is a similar exhibit. One of the  
21 most marked differences here is that you'll see that the  
22 acceleration component is roughly 50 percent in Culpepper  
23 Martin. So it's quite a bit higher in Culpepper Martin.  
24 Where we've got a one-third/two-thirds split in 27-and-5,  
25 it's roughly 50-50 in Culpepper Martin, so there will be

1 more acceleration.

2 One point to note on both of these graphs is, if  
3 you look at the blue section of the curve, which would tell  
4 you where you were starting to see significant quantities  
5 of acceleration, and move out about ten years and come up  
6 to the blue section, you'll see that it's a relatively  
7 insignificant amount of acceleration at that point. A lot  
8 of the acceleration is happening after. At a ten-year  
9 period on this graph, it's probably one-fifth/four-fifths  
10 acceleration and unique reserves.

11 Q. Does the Culpepper Martin area as modeled by  
12 simulation still justify the economic incentives to explore  
13 increasing the density?

14 A. The following page shows the individual well  
15 projections similar to 27-and-5, and we input some economic  
16 parameters into that to answer that very question.

17 And you can that see some of the significant  
18 differences here is Culpepper Martin being shallower than  
19 27-and-5, these well costs are a little bit cheaper. Same  
20 operating costs, same pricing assumptions. And we do see a  
21 rate of return that, while not as favorable as the 27-and-5  
22 rate of return, still looks worthy of pursuing, especially  
23 since there's some uncertainty in the model, and we can  
24 collect data to make us more certain about what's going to  
25 happen.

1 Q. It certainly warrants investigation as a pilot  
2 project at this point?

3 A. That's a fair statement.

4 MR. KELLAHIN: That concludes my examination of  
5 Mr. McCracken.

6 We move the introduction of his Exhibit Number 9  
7 in each of the books.

8 EXAMINER CATANACH: Exhibit Number 9 in each of  
9 the books will be admitted as evidence.

10 Questions, Mr. Chavez?

11 EXAMINATION

12 BY MR. CHAVEZ:

13 Q. Mr. McCracken, looking at your 27-5 history match  
14 and base projection, when you get as close a match as that  
15 appears to be -- I'm sorry --

16 A. That's fine.

17 Q. When your match is as close as that to actual  
18 production, do you think you're pretty good with your data  
19 at that point, or how far off are you when you have -- it  
20 matches that --

21 A. I think pretty good is a very fair  
22 characterization. You can match production in a number of  
23 different ways. There are different scenarios of back  
24 pressures and skins that we could have used to get this  
25 same match; but when you do, the pressures in the

1 individual blocks change.

2 And when we drill increased density wells and get  
3 those actual pressures and determine which of those sets of  
4 back pressures and skins was the set that matches up best  
5 with the pressure, then I think we move from pretty good to  
6 right on.

7 Q. When you talk about getting more certainty, what  
8 degree or certainty, or how big a change would you  
9 anticipate with a higher degree of certainty and the  
10 recovery factors and all that you've already projected with  
11 your data you have for the different models --

12 A. Without that pressure, I think trying to answer  
13 that question would be speculation on my part.

14 Q. Have you used this model before in anticipation,  
15 say, for -- How to put it? The way the model is used now,  
16 is there a problem with using it, say, with the infill  
17 wells on 160 acres?

18 A. To predict what the recovery for the 160-acre  
19 wells that to date have not been drilled would be?

20 Q. That's right.

21 A. I think that could be done, yes.

22 Q. With a good degree of confidence?

23 A. Similar degree of confidence to the 80 acres at  
24 this point. Again, the pressure data would make me more  
25 confident.

1           Q.    You heard me ask earlier about questions  
2           concerning statistical certainties that improve with more  
3           data.  Do you recall those questions?

4           A.    Yes, I do.

5           Q.    Do you have a response to those?

6           A.    I think the best response that I can give you is  
7           that this is a deterministic model, it really isn't a  
8           probabilistic model.  So deterministic factors are going to  
9           tell us how close this model is, and it's not really a  
10          probabilistic analysis.

11          Q.    So your model is then -- When you calibrate your  
12          model with more data, is it usable just in a smaller area,  
13          or how would you use that model to expand outside of the  
14          project or pilot area where the wells are drilled?

15          A.    The description of the reservoir becomes  
16          reasonably unique when you've constrained it with both  
17          production and pressure data, so your confidence in moving  
18          away from the model would be higher if you were constrained  
19          by both of those parameters.

20                However, if you move too far away you would have  
21          to gather similar data again and go through another process  
22          where you made a prediction, saw how close it was and then  
23          compared both the production and the pressure data to your  
24          model, to increase your confidence in that new area.

25          Q.    This is kind of an odd question, but when will

1 you know if you have enough data or enough pressures to  
2 say, We've got enough, we can go with this? Do you have a  
3 set point in your plans for that?

4 A. Within this particular area, or within these two  
5 particular areas, we feel that when we have this pressure  
6 data and we've had a first delivery from these wells and  
7 they are producing into the line, that our confidence is as  
8 high as it's ever likely to be on where we should go from  
9 there.

10 Q. Well, I understand that, but is there some point  
11 when you could say, I've got four wells here and I've got  
12 these pressures; any more pressures really won't  
13 significantly impact the model such that we need them?

14 A. Oh, I see where you're going. Without knowing  
15 what those four pressures are, I would hesitate to make a  
16 conclusion on that at this point. If you had a couple that  
17 matched your model pretty well and then a couple that threw  
18 you a curve, I think you would probably feel very strongly  
19 about getting the rest of the data. If you had four that  
20 all matched up with what you had predicted or you could  
21 easily change your model to the point where they did match,  
22 then I think the answer to that question would be yes. But  
23 without that actual data in hand, I think it's dangerous to  
24 try to draw a conclusion at this point.

25 MR. CHAVEZ: I think that's all I have.

## EXAMINATION

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BY EXAMINER CATANACH:

Q. Mr. McCracken, on your recovery profile graphs, are you -- with the total with infill drilling line that you've got, is that assuming four wells per section on that?

A. No, that's assuming the density of wells that's you know, applied for in the Application.

Q. Okay, just the eight wells?

A. Yes, eight for 27-5 and six for Culpepper.

Q. So the really uncertain factor that you put into these models is the initial pressure; is that correct? Or do you consider that to be a --

A. The initial pressure, I think, is probably fairly certain. It's a match on what the pressure is, let's say, April the 1st, 2000, or let's say at the point in time where an infill well was drilled that we feel like we don't have a good handle on it.

Initial pressures, we think, are probably within 50 p.s.i. either way.

Q. So you feel pretty good about all the data you've put into this simulation?

A. Yes, I do.

Q. Did you history-match anything but cumulative production? Did you history-match current production at

1 all? Or is that not typically done?

2 A. I'm not sure I understand the term "current  
3 production".

4 Q. Well, current producing rates for the units or  
5 for the area, that's not typically matched.

6 A. Oh, the -- Yes, we did, we don't have a  
7 presentation of it here in the exhibits. The match on the  
8 rates -- Actually, we matched the rates through time, and  
9 the match was good.

10 Q. It was?

11 A. Yes. There are individual variations during  
12 periods of curtailment where production tends to be  
13 erratic.

14 EXAMINER CATANACH: I don't have any more  
15 questions of this witness.

16 Mr. Chavez?

17 MR. CHAVEZ: Could I just ask a question?

18 FURTHER EXAMINATION

19 BY MR. CHAVEZ:

20 Q. Are you familiar with Conoco's pilot project?

21 A. To a certain extent, yes.

22 Q. Are pressures available to you from their pilot  
23 project that would help you to calibrate your model?

24 A. There are pressures available. I think the  
25 reason why it would be difficult to calibrate my model with



1     them is the geologic differences.

2             Q.     Can't that be accounted for by changing those  
3     parameters in the model?

4             A.     What we would have to do in my mind is build a  
5     geologic model of the Conoco project.

6             Q.     Okay. Have you considered taking pressures from  
7     other Burlington Dakota completions to use to calibrate  
8     your model?

9             A.     In fact, the one well that I referred to earlier  
10    that is outside the grid in an attempt to see if my model  
11    looked reasonable from a pressure standpoint with respect  
12    to that well -- the well was the San Juan 27-5 Unit Number  
13    109-E, which is approximately a mile to a mile and a half  
14    northeast of my gridded area -- when it was initially  
15    completed there was a bottomhole pressure taken, and that  
16    pressure was, I believe, 2733 pounds.

17            And I went into all of the blocks in my simulator  
18    where an infill well was drilled in that 1985-1986 time  
19    frame, where that well was drilled, and averaged their  
20    block pressures at that time, and that average came out to  
21    be 2770 pounds.

22            So that match is good. I hesitate to hang too  
23    much on that, though, because that well is outside the  
24    grid, and the range of those pressures that averaged 2770  
25    was about 2550 to 2950.

1           Q.    Could you use bottomhole pressures from infill  
2 wells in tracts that haven't been infilled in this 27-5  
3 unit to calibrate your model?

4           A.    For instance, 160 wells that are --

5           Q.    Yes.

6           A.    -- currently programmed or that are going to be  
7 drilled?

8           Q.    Yes.

9           A.    Probably so.

10           MR. CHAVEZ:  Thank you.

11           EXAMINER CATANACH:  This witness may be excused.

12           Mr. Kellahin?

13           MR. KELLAHIN:  That completes our presentation,  
14 Mr. Examiner.

15           EXAMINER CATANACH:  Mr. Kellahin, with regards to  
16 the unorthodox locations, I didn't hear all that testimony  
17 about a justification for each of those separate.  Was it  
18 just a mixture of factors for those locations?

19           MR. KELLAHIN:  Well, it's more specific than  
20 that, Mr. Examiner.  You've provided Mr. Babcock an  
21 opportunity to give you a geologic narrative as to the  
22 locations.  We can provide a narrative to explain the  
23 topographic maps that are already in the exhibit book to  
24 specifically identify each location, if that helps you.

25           EXAMINER CATANACH:  So the unorthodox locations,

1 some are topographic and some are geologic; is that my  
2 understanding?

3 MR. KELLAHIN: Well, it's a combination of both.  
4 Mr. Babcock's first choice on a geologic location was not  
5 necessarily achievable and had to be moved further. In  
6 most instances, his geologic choice put the well at an  
7 unorthodox location inherently, because they were in  
8 undrained portions of the pool, because that's what's left  
9 for you once you follow the existing pattern.

10 Where they would fine-tune, had a surface  
11 component to it, and if -- It may help you, and I'm happy  
12 to draft the order for you if you would like, but we will  
13 include documentation to give it a well-specific  
14 explanation as to how you combine the two to get the  
15 location.

16 EXAMINER CATANACH: I would like a well-specific  
17 explanation on these locations --

18 MR. KELLAHIN: All right, sir.

19 EXAMINER CATANACH: -- if you could provide that  
20 to me.

21 MR. KELLAHIN: I'd be happy to do that.

22 EXAMINER CATANACH: I am also a little concerned,  
23 especially on the Culpepper Martin Unit, about non-notice  
24 to royalty interest owners. I'm not so concerned within  
25 the 27-5 unit, it does concern me in the Culpepper Martin

1 Unit.

2 MR. KELLAHIN: Well, I understand that, Mr.  
3 Examiner. The Division rules don't require it, we  
4 therefore didn't do it. Remember when we re-wrote the  
5 rules last year, the reason the overrides and royalties  
6 were left off notifications in cases like this is because  
7 it is the inherent responsibility contractually, by lease  
8 obligation, for the working interest owner and the lessee  
9 to take care of those individuals. And so that's what our  
10 testimony has been, and we'll do it in that fashion.

11 If you decide that you want us to go back and  
12 renotify, then we'll do what you tell us to do.

13 EXAMINER CATANACH: I want you to notify the  
14 interest owners, the royalty interest owners and overrides  
15 in the Culpepper Martin Unit.

16 MR. KELLAHIN: All right, sir.

17 EXAMINER CATANACH: I think we can dispense with  
18 that in the other San Juan 27-5 Unit.

19 MR. KELLAHIN: We'll be happy to do that, sir.

20 EXAMINER CATANACH: It would just make me feel  
21 more comfortable about it.

22 MR. KELLAHIN: Then we'll do it.

23 EXAMINER CATANACH: Okay. Is there anything  
24 further in this case?

25 MR. KELLAHIN: There's representatives from the

1 Bureau of Land Management here, and I don't know if they  
2 want to speak or not.

3 MR. TOWNSEND: Yeah, we want to make a  
4 statement --

5 EXAMINER CATANACH: Okay.

6 MR. TOWNSEND: -- if I don't lose my voice first.

7 EXAMINER CATANACH: Mr. Townsend?

8 MR. TOWNSEND: Yes, I'd like to make a statement  
9 that represents the position of the Bureau of Land  
10 Management concerning the technical aspects of Burlington  
11 Resources' Applications here today.

12 NMOCD Case Numbers 12,508 and 12,509 are to  
13 increase the Dakota formation well density to a maximum of  
14 four wells per gas proration unit, unorthodox, nonorthodox  
15 locations, in a portion of the 27-5 Unit and the Culpepper  
16 Martin project area.

17 Based upon the technical data presented by  
18 Burlington to the BLM on September 28th of this year, a  
19 review of the proposed application that we got and received  
20 from them, and the testimony we've heard here today, we are  
21 in support of these pilot projects. These projects will be  
22 critical in gathering additional reservoir engineering and  
23 geological data for the specific purpose of determining the  
24 proper well density in the Dakota formation.

25 However, the BLM has concerns regarding the

1 potential drainage situation that we've heard today and  
2 that we've previously discussed. In the Culpepper Martin  
3 pilot project area the drainage situation exists because of  
4 the different mineral ownerships. These concerns were  
5 addressed in a letter to Burlington dated October 13th of  
6 2000.

7 Just to take a minute and to digress from the  
8 pilot projects, if the pilot projects are successful and  
9 they are approved by the NMOCD, the BLM supports the  
10 drilling windows and the spacing rules for the Mesaverde  
11 and the Dakota to be similar or the same. We support this  
12 because of the commingling of the Mesaverde reservoir and  
13 the Dakota reservoir and minimized surface disturbances.

14 Also, if the pilot projects are successful, at  
15 this juncture the BLM is also in favor of Basinwide rules  
16 as similar to the Mesaverde. This would benefit all  
17 operators so that they could determine their own economics  
18 in whether to deepen the well to try to recover additional  
19 Dakota reserves.

20 In summary, the BLM is in support of these pilot  
21 projects as proposed by Burlington. The BLM contends that  
22 any drainage situations that may arise as a result of these  
23 pilot projects can be mitigated through existing processes  
24 and procedures. These pilot projects will provide valuable  
25 information to determine optimum well density and will

1 maximize recoverable efficiency towards other formations.

2 The BLM is also in support of the other  
3 unorthodox locations, which potentially maximize the  
4 potential recoverable reserves and minimizes the additional  
5 surface disturbances.

6 That's my statements concerning the technical  
7 portions. Mr. Ruben Sanchez was wanting to address the  
8 surface portion.

9 EXAMINER CATANACH: Thank you, Mr. Townsend.

10 Mr. Sanchez?

11 MR. SANCHEZ: Some of the things that I will say  
12 are parallel to what Mr. Townsend just addressed, because  
13 they do impact a lot of the surface resources, which is  
14 predominantly my concern for myself and my staff with the  
15 environmental protection section.

16 We do promote and will continue to promote  
17 environmentally responsible permitting of the pilot  
18 projects as these projects are presented and carried  
19 forward, based on approval by the NMOCD.

20 We also encourage industry to continue looking  
21 and considering directional drilling or any other  
22 innovative ways to produce the subsurface resources, to  
23 minimize the impacts to other resources that are shared by  
24 the public in general.

25 The staff with the environmental protection will

1 continue to ensure conformance with NEPA for all permitted  
2 actions that come out of our section. Professional  
3 judgment will also continue to be applied for all on-sites,  
4 whether they be pilot or just a spacing that have already  
5 been previously approved, particularly right now as we go  
6 through the EIS revamping of the Resource Management Plan.

7 We'd also like to encourage NMOCD to consider the  
8 flexibility of the nonstandard locations, as this will help  
9 reduce surface resource impacts. Surface resources must be  
10 taken into account if there is to be something left for  
11 future generations to enjoy within the Four Corners area.

12 Any future projects that are presented that will  
13 include or increase well density severely impacts all of  
14 our programs -- those being wildlife, recreation,  
15 grazing -- that are enjoyed by the public in general. And  
16 that is why, I guess, from my standpoint, from the surface  
17 impact side, we'll be strongly supporting looking for  
18 innovative ways to develop that.

19 On behalf of the Bureau, we are not here to  
20 express opposition to your development efforts. That is  
21 not in any way -- should not be taken, what I just said.  
22 We're all for it. It's just, there's other resources which  
23 we hope to consider.

24 Thank you.

25 EXAMINER CATANACH: Thank you, Mr. Sanchez.



1 Anything further?

2 MR. HAWKINS: Yes, Bill Hawkins with BP Amoco.  
3 We'd like to make a statement in support of the Application  
4 by Burlington.

5 BP Amoco supports the approval of the 80-acre  
6 infill pilot project in both of these locations in the  
7 Basin-Dakota Pool. We support the testing of 80-acre  
8 infill pilots in several parts of the pool for proving the  
9 concept for the rest of the pool.

10 We don't have a plan to conduct an infill pilot  
11 on any of our acreage, and I think you've heard today  
12 difficulty in trying to identify pilot areas where  
13 correlative rights can be protected.

14 We believe if these pilots are successful, that  
15 ultimately 80-acre infill development for the entire Basin-  
16 Dakota Pool should be approved. The Dakota formation is  
17 generally lower in permeability than the Mesaverde, where  
18 the NMOCD has already approved 80-acre infill. The most  
19 economic way to implement 80-acre development in the Dakota  
20 is to tag along with the 80-acre infill development in the  
21 Mesaverde, using common wellbore, well-location pads and  
22 roads.

23 The 80-acre infill development in the Mesaverde  
24 is already undergoing, and the longer we wait to approve  
25 80-acre infill of the Dakota, the more 80-acre Dakota

1 locations may be left undeveloped, which would create  
2 waste.

3 We ask that the NMOCD approve these pilot  
4 projects with a short six- to twelve-month time frame for  
5 implementation. And we ask the NMOCD to recall both  
6 Burlington and Conoco for hearing to provide the data and  
7 results obtained from the pilot projects and to consider  
8 80-acre increased density for the development of the entire  
9 pool.

10 EXAMINER CATANACH: Are there any other  
11 statements in this case?

12 Mr. Kellahin, if you would be so kind, I would  
13 like draft orders in both these cases.

14 And with that, Case 12,508 will be taken under  
15 advisement, and Case 12,509 will be continued to the  
16 November 16th hearing, which I assume will give you proper  
17 time for notice in this case?

18 MR. KELLAHIN: Yes, sir. We'll discuss after the  
19 hearing tabulating the data to send the notice out. I  
20 think we can do it very quickly. And before we decide  
21 whether to close or continue the case, let me check and see  
22 when I can get my notices satisfied. Is that how you'd  
23 like to do it?

24 EXAMINER CATANACH: Well, I think we need to  
25 continue it to November 16th at the earliest.

1 MR. KELLAHIN: At the very earliest.

2 EXAMINER CATANACH: At which point, we can always  
3 continue it further from that --

4 MR. KELLAHIN: Let's do that.

5 EXAMINER CATANACH: -- if we need to.

6 MR. KELLAHIN: Yes, sir.

7 EXAMINER CATANACH: Okay. All right, thank you.

8 (Thereupon, these proceedings were concluded at  
9 12:44 p.m.)

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I do hereby certify that the foregoing is  
a true and correct copy of the proceedings at  
the Examiners hearing of Case No. \_\_\_\_\_  
heard by me on \_\_\_\_\_ 19\_\_\_\_.

\_\_\_\_\_  
Off 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 24th, 2000.



STEVEN T. BRENNER  
CCR No. 7

My commission expires: October 14, 2002