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STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

COMMISSION HEARING

IN THE MATTER OF: Case 9764

Application of Meridian Oil, Inc.,
for a highly-deviated directional
drilling pilot project, unorthodox
gas well location and an exception
to Rule 2(b) of the Special Rules
Governing the Blanco-Mesaverde Pool,
San Juan County, New Mexico.

TRANSCRIPT OF PROCEEDINGS

BEFORE: WILLIAM J. LeMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
WILLIAM HUMPHRIES, COMMISSIONER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

January 18, 1990

ORIGINAL

CUMBRE COURT REPORTING
(505) 984-2244

A P P E A R A N C E S

FOR THE OIL CONSERVATION COMMISSION:

ROBERT G. STOVALL, ESQ.
State Land Office Building
Santa Fe, New Mexico 87501

I N D E X

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1 MR. LeMAY: The meeting will come to order.
2 This is the Oil Conservation Commission, the Commission
3 of three Bills. We haven't met for a while. Happy New
4 Year.

5 Within the record, I'd like to establish some
6 dates of Commission hearings because they do have to be
7 advertised.

8 (Thereupon, a discussion was
9 held off the record.)

10 MR. LeMAY: Case No. 9764.

11 MR. STOVALL: Application of Meridan Oil,
12 Inc., for a highly-deviated directional drilling pilot
13 project, unorthodox gas well location and an exception
14 to Rule 2(b) of the Special Rules Governing the
15 Blanco-Mesaverde Pool, San Juan County, New Mexico.

16 Applicant requests this case be continued to
17 the February 15, 1990, Commission hearing.

18 MR. LeMAY: Is there any objection to that
19 extension? If not, we shall continue that case to the
20 15th of February.

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1 CERTIFICATE OF REPORTER

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3 STATE OF NEW MEXICO)

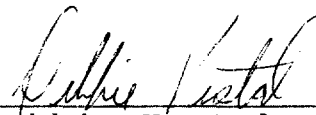
4) ss.

5 COUNTY OF SANTA FE)

6 I, Debbie Vestal, Certified Shorthand
7 Reporter and Notary Public, HEREBY CERTIFY that the
8 foregoing transcript of proceedings before the
9 Commission of the Oil Conservation Division was
10 reported by me; that I caused my notes to be
11 transcribed under my personal supervision; and that the
12 foregoing is a true and accurate record of the
13 proceedings.

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

18 WITNESS MY HAND AND SEAL February 18, 1990.

19
20 
21 Debbie Vestal
22 CSR No. 400
23
24
25

CUMBRE COURT REPORTING
(505) 984-2244

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date FEBURARY 15, 1990 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
<i>W. J. Kelbourn</i>	<i>Kelbourn Kelbourn Aubrey</i>	<i>Santa Fe</i>
Kent Beers	Meridian Oil Inc.	Farmington
Jim CRAODICK	" "	"
G.T. DUNN	" "	"
Bob Hopkins	" "	"
Greg JENNINGS	" "	"
KENT LUND	AMOCO PROD CO.	DENVER
LARRY EMMONS	" "	"
<i>Bruce Hulme</i>	<i>Byram</i>	<i>Santa Fe</i>
<i>John F. Eichelmanner</i>	<i>Burlington Resources</i>	<i>Santa Fe</i>
<i>Don Clifton</i>	<i>Meridian Oil Inc</i>	<i>Houston, Tex</i>
<i>Gavin Smith</i>	<i>" "</i>	<i>" "</i>

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION
CASES 9764 and 9765

COMMISSION HEARING

IN THE MATTER OF:

Application of Meridian Oil, Inc., for a
Highly-Deviated Directional Drilling Pilot
Project, Unorthodox Gas Well Location and
an Exception to Rule 2(b) of the Special
Rules Governing the Blanco-Mesaverde Pool,
San Juan County, New Mexico

TRANSCRIPT OF PROCEEDINGS

BEFORE: WILLIAM LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

February 15, 1990

ORIGINAL

CUMBRE COURT REPORTING
(505) 984-2244

A P P E A R A N C E S

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I N D E X

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By Mr. Kellahin

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1 CHAIRMAN LEMAY: Now I'll call Cases 9764
2 and 9765.

3 MR. STOVALL: These are the applications of
4 Meridian Oil, Inc., for a highly-deviated directional
5 drilling projects, unorthodox gas well locations and
6 exceptions to Rule 2(b) of special rules governing the
7 Blanco-Mesaverde Pool, San Juan County, New Mexico.

8 CHAIRMAN LEMAY: Do I hear a motion on
9 these cases? Mr. Kellahin?

10 MR. KELLAHIN: Mr. Chairman, for the record
11 my name is Tom Kellahin. I'm an attorney with the
12 Santa Fe law firm of Kellahin, Kellahin and Aubrey.
13 I'm appearing today on behalf of Meridian Oil, Inc.

14 I've discussed this matter with Mr. Lund,
15 who is attorney for Amoco appearing today on their
16 behalf, and he has no objection to my motion at this
17 time to consolidate both those cases for hearing
18 purposes this morning, and we would so move.

19 CHAIRMAN LEMAY: We move the cases be
20 consolidated. Are there any objections to this? If
21 not, the cases will be consolidated.

22 I'll now call for additional appearances in
23 Cases 9764 and 9765.

24 MR. LUND: Good morning, Mr. Chairman. My
25 name is Kent Lund appearing on behalf of Amoco

1 Production Company, and I'm appearing in association
2 of Charles Sanchez of Belen, New Mexico.

3 CHAIRMAN LEMAY: Thank you, Mr. Lund.
4 You'll have witnesses for us today, or not?

5 MR. LUND: Potentially. As the Chairman
6 may be aware, the only thing we're really concerned
7 about is the deliverability allowable calculations for
8 the proposed proration units with these deviated
9 wellbores. We don't object to the fact that Meridian
10 wants to drill them. In fact, we're excited about
11 that. We just have some concerns for the correlative
12 rights, and that's our issue today.

13 CHAIRMAN LEMAY: Thank you, Mr. Lund.
14 Additional appearances in the case?

15 MR. KELLAHIN: Mr. Chairman, I would like
16 to introduce at this time the General Counsel of
17 Meridian Oil, Inc., Mr. Gavin Smith. Mr. Smith is a
18 member of the Texas bar and has come today to be
19 present for the hearing today. Mr. Smith, would you
20 please stand.

21 CHAIRMAN LEMAY: Mr. Smith, we're glad to
22 have you hear in Santa Fe.

23 At this time we will swear in all the
24 witnesses who will be giving testimony. Please rise
25 and raise your right hands.

1 (Thereupon, all witnesses were sworn.)

2 CHAIRMAN LEMAY: Mr. Kellahin, you may
3 proceed.

4 MR. KELLAHIN: Mr. Chairman, we want to
5 attempt to do something a little differently before
6 the Commission today than is our typical presentation
7 form. In the past, in disputed cases, it is often the
8 style to take each of the experts and lead them
9 through a presentation of their technical case. We
10 believe that is not the kind of case we want to
11 present to you today.

12 As Mr. Lund indicated, we are pleased and
13 delighted with the Examiner Order in all issues except
14 one. We are pleased that the Examiner has found that
15 this unique opportunity to attempt to recover
16 additional gas reserves out of the Mesaverde Formation
17 in the San Juan Basin is one that he endorses.

18 The topic of discussion today is going to
19 be a project, a pilot project, if you will, for what
20 we characterize as a highly-deviated well, a
21 high-angle well, if you please. We are selecting to
22 try to determine whether or not that technology will
23 give us an opportunity to further develop gas reserves
24 out of the Mesaverde Formation.

25 I think we all appreciate and recognize the

1 wonderful success we have all enjoyed from the in-fill
2 program in the Mesaverde. Our background information
3 we want to present to you today explains some of the
4 bases upon which the Examiner entered the order
5 endorsing the fact that we have the opportunity to
6 recover yet again reserves that are not yet being
7 produced. So we are pleased with a number of his
8 findings.

9 The single exception that we have with the
10 order as entered is the establishment of a special
11 project allowable. And that will be the focus of our
12 concentration this morning. I want to present to you
13 three technical people to give you a background on the
14 project, but the focus, then, will be for them to
15 explain to you the special project allowable.

16 As you know, the Mesaverde is a prorated
17 gas pool. We have sought to come up with a special
18 project allowable within the context and the framework
19 of the proration system for that reservoir. In doing
20 so, the technical people will talk to you about how to
21 make that calculation.

22 In order to have the economic incentive to
23 go forward with this project, we are requesting a
24 modification of the Examiner Order. We are requesting
25 that in order to calculate the spacing unit allowable,

1 that you grant us the right to take the deliverability
2 of the high-angle well and multiply that
3 deliverability by two, and subsequently integrate that
4 into the allowable calculation.

5 Mr. George Dunn is a reservoir engineer who
6 will make the first presentation and show you his
7 justification for his allowable request. He'll talk
8 to you about his economics and we'll get into all the
9 ramifications of that particular issue.

10 I'll also present to you Mr. Greg Jennings,
11 Meridian's geologist, who will give you a presentation
12 of the geologic basis upon which we have predicated
13 the pilot project.

14 My last technical witness is Mr. Louis
15 Jones. He is known to the Commission, he has
16 testified before you on a number of occasions on
17 prorationing, and he is prepared to discuss with you
18 the mechanics of how to handle the formula.

19 One of the things that we did not give
20 Examiner Catanach the opportunity to hear is the
21 question of the maximum possible producing rate for
22 the high-angle well, and that was Amoco's concern.
23 They were concerned that our request did not have a
24 cap or a ceiling on the producing rate for the spacing
25 unit, and it was possible, then, under our

1 presentation, that the offsetting spacing units might
2 have to compete against a high-angle well in a way
3 that they would not be exposed to competition if this
4 had been a vertical well.

5 We want to discuss that issue and hopefully
6 address some of their concerns about establishing what
7 we think is an appropriate ceiling or cap on the total
8 allowable for our spacing unit that will hopefully
9 satisfy your concerns and Amoco's concerns about any
10 opportunity for an unfair advantage.

11 Amoco was at the earlier hearing. I think
12 everybody agrees that this is technology that ought to
13 be explored in New Mexico. I'm personally delighted
14 that Meridian has chosen New Mexico to do this
15 activity, but I'm also hear to tell you that unless we
16 can have an incentive, in terms of this project
17 allowable as we propose, then unfortunately we're not
18 going to be able to go ahead with the project.

19 I have technical witnesses that will
20 explain to you that position, but that is part of the
21 presentation today. And therefore I would request,
22 Mr. Chairman, that we incorporate for the record, so
23 that we do have a complete record, the Examiner
24 transcript so that I don't have to go through all the
25 building steps to build the case, and we'll focus

1 directly in, then, on this question of this project
2 allowable.

3 CHAIRMAN LEMAY: Are there any objections
4 to incorporation of the transcript?

5 MR. LUND: No objection.

6 CHAIRMAN LEMAY: Thank you. The transcript
7 of the Examiner hearing will be a part of this
8 record.

9 MR. KELLAHIN: Mr. Chairman, so we can
10 focus on that portion of the Examiner Order that gives
11 us our concern, I would like to circulate to you a
12 copy of the existing order entered in this case, along
13 with a proposed language change that we can discuss
14 this morning that we believe solves our concerns.

15 In order to approve our request before the
16 Commission, the language we have proposed, which is
17 referenced number 8, refers to page 6 of the existing
18 order and looks to the ordering paragraphs. It's
19 ordering paragraph number 8 that established under the
20 Examiner Order the level of the allowable for the
21 spacing unit.

22 What Mr. Catanach approved was the option
23 to use the deliverability of the high-angle well or,
24 in the alternative, the sum of the deliverabilities of
25 the two vertical wells in the spacing unit. In each

1 of these cases we have an original Mesaverde well and
2 an in-fill well. The language change here is simply
3 to provide authority to take twice the deliverability
4 of the high-angle well in the calculation. The
5 further discussion in that subparagraph (1) is our
6 efforts to put in place a cap or a ceiling.

7 With your permission, Mr. Chairman, I would
8 like to call our first witness, Mr. George Dunn.

9 CHAIRMAN LEMAY: Please proceed.

10 GEORGE T. DUNN

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

13 MR. KELLAHIN: Mr. Chairman, while Mr. Dunn
14 was taking his place in the witness chair, I have
15 handed out to Mr. Lund and to other participants and
16 to the Commission, Meridian's exhibit book. We have
17 simply marked the exhibit book as Meridian Exhibit 1,
18 and then each of the pages and displays in the book
19 are numbered one through whatever the last number is.

20 We have taken some of those displays and
21 made larger copies to aid in understanding the
22 testimony of the technical people, but if you have one
23 of the covered booklets, this will contain all of the
24 exhibits we're presenting today.

25

EXAMINATION

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BY MR. KELLAHIN:

Q. Mr. Dunn, for the record, would you please state your name and occupation.

A. My name is George Dunn. I'm a senior staff reservoir engineer for Meridian Oil, Incorporated, in Farmington, New Mexico.

Q. Would you summarize for the Commission what has been your personal involvement with this project?

A. I was on an initial team which consisted of an integration of several departments within Meridian Oil, and I was the reservoir portion of that team, to determine some methods to enhance ultimate recovery in the Mesaverde Formation in the San Juan Basin.

Q. How long have you worked as part of Meridian's technical team on this particular project?

A. Approximately 9 to 10 months now.

Q. You have a bachelor's degree in petroleum engineering, sir?

A. Yes, sir. I have a bachelor's degree from the Colorado School of Mines.

Q. What year?

A. 1979.

Q. You previously qualified as an expert reservoir engineer before this Division?

1 A. Yes, sir.

2 MR. KELLAHIN: Mr. Chairman, we tender Mr.
3 Dunn as an expert engineer.

4 CHAIRMAN LEMAY: His qualifications are
5 accepted.

6 Q. Mr. Dunn, would you summarize for the
7 Commission--and perhaps let's go to the locator map.
8 Show us the two spacing units, if you will, that are
9 the two pilot projects that we're discussing this
10 morning.

11 A. This is a locator map that has the outline
12 of the Blanco-Mesaverde pool in orange. Farmington is
13 approximately in this area, Bloomfield. Within that
14 locator map we've highlighted 9 section areas for the
15 Howell "E" 2, proposed Howell "E" 2R well, and also
16 around the proposed Riddle 1R in the center,
17 basically, of the Blanco-Mesaverde pool.

18 As you can see, we've blown up for both the
19 Howell, on the right, and the Riddle, those
20 nine-section plats. In addition, I might point out
21 now, that we'll be talking briefly about a couple of
22 other proration units that are within this locator
23 map, one being the Howell "D" 3B proration area and
24 it's in this location basically in between the two
25 areas we're talking about, and then we're going to

1 move up into the northwest section and talk about the
2 Scott 2R.

3 The Howell "E" 2R is located in Township 30
4 North, Range 8 West, and it's in Section 14. It would
5 be in the east half. Colored in yellow is the acreage
6 that Meridian operates and outside-operated acreage is
7 in white. Basically these three sections to the east
8 of the Howell "E" 2 proration unit is part of the
9 Northeast Blanco Unit, and all of the other sections
10 are Amoco-operated.

11 Q. Summarize for us, Mr. Dunn, what was the
12 purpose of the study?

13 A. The purpose of this study was two-fold.
14 Number one, to go in and look for old open-hole
15 Mesaverde wells that produce inefficiently due to the
16 open-hole collapsing and/or not even being drilled all
17 the way through the Mesaverde Formation. On top of
18 that, we were in search of additional ways to increase
19 ultimate recovery because we're nearing the end of the
20 in-fill program, and after the in-fill program is
21 done, we're in search of a way to increase recovery
22 beyond those two, and there are ways to do that.

23 Q. Why did you select Mesaverde as the
24 formation or the pool to study?

25 A. It's the largest reserve base in the San

1 Juan Basin. It's also one of the largest of Meridian
2 Oil's, and therefore it offers a high potential for an
3 increased recovery and impact to both Meridian Oil and
4 the State and the San Juan Basin.

5 Q. Why have you selected the use of
6 highly-deviated wellbore technology or high-angle
7 wells to study in this particular pool?

8 A. The concept of the highly-deviated well is
9 to determine if we can intersect additional pods of
10 sand, reservoir containing gas that are not in
11 communication with vertical well due to permeability
12 barriers or whatever. And these have been indicated
13 before in several cases, one in Van Everdine's
14 testimony for the in-fill program. He discussed some
15 of the lenticular nature of the sand.

16 In addition, we'll show some redrill
17 criteria where we've redrilled wells and gained
18 additional recovery in the reservoir.

19 Q. Why use highly-deviated wellbore technology
20 for exploring the additional reserves in the Mesaverde
21 versus a third vertical well in the spacing unit?

22 A. The highly-deviated well will afford us
23 increased chances of intersecting these pods basically
24 by increasing the cross-sectional area that we're able
25 to contact within the proration unit.

1 Q. Describe for us the criteria, Mr. Dunn,
2 that the project technical people selected in order to
3 identify spacing units to use for the pilot project.

4 A. Again, the initial emphasis was to locate
5 areas where we had old open-hole completions. We felt
6 they were not competitive with offset leases. In
7 addition, that there was inefficient production going
8 on. That was the initial emphasis.

9 Then, as we narrowed down to these location
10 and wells, with the introduction of the concept of the
11 highly-deviated well we looked for areas of
12 100-percent working interests so that we could
13 initiate this project quickly, gain data so that if it
14 was successful when we went to outside owners,
15 partners and other areas, we would have data to show,
16 then, that it's worth the extensive capital increase
17 to actually drill these wells.

18 Also, these two just happened to have
19 surface locations. As you can see, they're dotted in
20 orange or, excuse me, they're just offset to the
21 orange of the original well, which is tucked into the
22 northern portion of the proration unit. Our idea is
23 to be able to drill to the south the full length of
24 this proration unit in the drilling window and get
25 away from the old wellbore and what it saw within the

1 Mesaverde.

2 Q. Why have you and the other technical people
3 selected the spacing unit for the Riddle well and the
4 Howell well for the pilot project?

5 A. These are just two of several wells that we
6 could have selected. We propose two wells to be able
7 to fully test the technique. We feel like one well
8 either did mechanical failures or productivity
9 failures may not fully explain whether or not this is
10 a successful technique to use; so, we selected two
11 that are multiple locations that we could select. The
12 primary emphasis of this was this is the meat of the
13 Mesaverde in this area. It reduces potential
14 productivity problems that we might encounter on the
15 fringe, so we went to the center of the proration
16 unit.

17 In addition, there has been several
18 successes of vertical redrills and therefore in terms
19 of increasing reserves, so we have a statistical base
20 to compare these deviated wells against the vertical
21 wells that exist out there that have already been
22 redrilled.

23 Q. I think page 2 of your exhibit book is a
24 reproduction of each of the two spacing units?

25 A. That's correct.

1 Q. After that display is page 3, and that
2 looks at the current deliverabilities of the wells in
3 the Howell area?

4 A. That's correct.

5 Q. Let's go to that, Mr. Dunn.

6 A. This is the same nine-section plat here for
7 the Howell "E" 2 area.

8 Q. When we look at the spacing unit for the
9 Howell and its two vertical wells that exist on that
10 spacing unit and look at the current deliverabilities
11 of those wells around that spacing unit, what do you
12 find?

13 A. You find that the proration unit of the
14 Howell "E" 2 and Howell "E" 2A has a significantly
15 lower deliverability than those offset to it. And
16 this is primarily due to the Howell "E" 2 which is an
17 old open-hole completion that I've already discussed.
18 Therefore, we see that we're in a less competitive
19 situation because of this old wellbore.

20 Q. When we look at the spacing unit
21 surrounding the Howell spacing unit, do each of those
22 corresponding spacing units have an original and an
23 in-fill well on them?

24 A. That is correct.

25 Q. In terms of correlative rights, Mr. Dunn,

1 do you see any opportunity to have any of the
2 offsetting owners' correlative rights impaired if the
3 pilot project is approved, as we propose it be
4 amended, by this Commission?

5 A. No, I do not.

6 Q. And why not?

7 A. The proposal is to set a cap for the two
8 times the "D" of the highest proration unit that is
9 currently drilled with two vertical wells. That would
10 be--in other words, what we're adjusting this cap to
11 is the risk factor that is there, if we were to drill
12 two vertical wells. It would protect them the same as
13 us coming in and drilling two new vertical wells, the
14 highest risk that's out in the basin currently.

15 Q. In addition, those spacing units are
16 already competitive insofar as they do have or had an
17 original and an in-fill well?

18 A. That is correct.

19 Q. And currently their deliverabilities exceed
20 yours?

21 A. At least by double.

22 Q. Let's go to page 4 of the exhibit book.
23 Before we discuss your conclusions, Mr. Dunn, let's
24 look at what you have presented. What are you
25 showing?

1 A. This is a linear material balance, a P/Z
2 plot, for the Scott 2 and Scott 2R wells. This was a
3 well that I pointed to in the northeast section of
4 this locator map earlier. It is a plot of bottom-hole
5 pressure/Z, versus cumulative production, for an
6 original well and then for a redrill well.

7 Q. What's the conclusion?

8 A. The conclusion is that the Scott #2 had
9 potential original gas in place of about five and a
10 half Bcf. By redrilling this well, you can see that
11 we've changed the slope of this line and increased
12 reserves somewhere upwards of three-fold.

13 Q. What does that tell you about the
14 Mesaverde?

15 A. It tells us that--and I should mention,
16 also, that well was within 2- to 300 feet of the old
17 wellbore--that you're capable of picking up areas that
18 are not being produced by an original wellbore by
19 moving within the Mesaverde, and that's because of the
20 lenticular nature of the sand, and also because of the
21 permeability and porosity enhancements that can occur
22 throughout the basin.

23 Q. You have found that occurrence in the Scott
24 spacing units. Do you find that to occur in other
25 spacing units in the Mesaverde?

1 A. In all of the redrills we've done so far,
2 this is a typical example.

3 Q. Let's go to the P/Z curve on the Howell
4 wells, Mr. Dunn. Having plotted the pressure versus
5 cum. for the Howell wells, what do you conclude?

6 A. This is basically the identical conclusion
7 as from the Scott 2 and Scott 2R except it does show
8 one additional item. The initial pressure P_i for the
9 Howell "D" 3B was approximately 70 psi higher than the
10 Howell "D" 3 was. Therefore, it's additional proof of
11 picking up additional pay that was not being produced
12 by the original Howell "D" #3 well. Again, you can
13 see the increase in reserves by the change in slope of
14 the line by plotting these two together.

15 Q. That confirms, then, the necessity of the
16 in-fill program for 320 gas spacing in the Mesaverde
17 pool?

18 A. It confirms the necessity of the in-fill
19 program and also confirms the necessity to search and
20 look for areas where we can pick up additional
21 recovery within the Mesaverde.

22 Q. Let's go on now to the discussion of the
23 Howell in terms of its vertical and horizontal
24 locations. We can leave these up, and let's look at
25 the Howell map. All right. We're looking at larger

1 copies of what is page 6 to your exhibit book?

2 A. Correct.

3 Q. So that we have an understanding of the
4 basis for the project, lead us through a discussion of
5 how the well is going to be drilled and what you hope
6 to accomplish with the drilling of the highly-deviated
7 well.

8 A. Basically, in terms of just the drilling
9 side of it, we'll drill vertically to a kick-off point
10 and kick off and build a ramp angle all with the mud.
11 Then we'll set approximately 100 feet above the
12 Mesaverde Formation, we'll set an intermediate string
13 of casing, and we'll drill out and be drilling the
14 ramp with gas all the way through the Mesaverde.

15 To our knowledge, this has not been
16 attempted in the State of New Mexico nor in the
17 western half of the United States. So the interesting
18 part, from a drilling standpoint, not only is the
19 highly-deviated, but we're doing this with gas. From
20 a reservoir standpoint, what we have is a plan view of
21 the proposed wellbore, proposed wellbore, and a
22 cross-sectional view of the proposed wellbore, and
23 spotted on this is the original Howell "E" #2 well,
24 the proposed Howell "E" 2R deviated well, and then the
25 Howell "E" 2A in-fill well.

1 We've colored in on here three of the
2 intervals within the Mesaverde. Those can even be
3 broken down further, but basically we'll enter into
4 the Cliff House Formation, drill through the Cliff
5 House at our ramp angle of approximately 68 degrees,
6 and this entry point will not infringe upon the
7 790-foot setback. In fact, the plan right now is
8 approximately 1000 feet from the north line. We'll
9 intercept the Menefee, drill through the Menefee, and
10 then through the lower Point Lookout, and TD at a
11 point no closer than 790 feet from the south line.
12 This is shown basically on the plan view to the
13 right.

14 At the same time we have colored in the
15 formations and where approximately we will intercept
16 them within this proration unit as we drill through.

17 Q. Your display also shows you the location of
18 the two existing vertical wells in the spacing unit?

19 A. That's correct. On the plan view you can
20 see it somewhat easier. The Howell "E" #2 will be
21 just north of the surface location of the Howell "E"
22 2R but will be almost 900 feet away when we actually
23 intercept the top of the Mesaverde and the Cliff
24 House.

25 The Howell "E" 2A is tucked down in the

1 right-hand corner of this drilling window, and we'll
2 be drilling due south towards the south line. We'll
3 require this whole drilling window in terms of use for
4 drilling, but if at any time we approach any of those
5 setbacks, then we'll determine if we can get away,
6 make a correction to not go across that, or stop the
7 well.

8 Q. We've characterized this as a
9 highly-deviated or high-angle well. Approximately
10 what is the angle for the Riddle and the Howell well?

11 A. The Howell, as I've mentioned, is about 68
12 degrees; the Riddle will be about 73 degrees.

13 Q. How is this different from a horizontally
14 drilled well?

15 A. A horizontally drilled well will come down,
16 and when it builds its angle it will come to a
17 90-degree bend, and it would drill across, in terms of
18 speaking on the Mesaverde, would drill through just
19 the upper Cliff House, which is the top formation or
20 you could pick any of the other formations. It would
21 not be in contact with the full interval of the
22 Mesaverde.

23 Therefore, you would only produce from a
24 part of the Mesaverde. That's why the horizontal
25 technique is not conducive in this situation. The

1 other option would be to drill multiple laterals at an
2 extremely high cost.

3 Q. Describe for us, Mr. Dunn, what you see or
4 what your work group concluded to be the advantages of
5 the highly-deviated well?

6 A. The major advantage of the highly-deviated
7 well is, in the case of the Howell "E" 2R, you'll note
8 that we drilled in the Mesaverde formation for almost
9 3150 feet. That's about a three-fold increase of
10 contact area over the vertical wells which are, at
11 maximum, about 1,073 feet, 1100 feet, approximately.
12 So it affords us the advantage of contacting
13 three-fold the formation across the proration unit,
14 and increases our chances of intersecting these areas
15 that aren't being drained with the vertical wells.

16 Q. You've identified on your display some
17 disadvantages. Why have you selected those as
18 disadvantages and what are they?

19 A. The main disadvantage is, since this is a
20 brand-new technique, it includes a high risk of
21 failure and/or a high risk of increased capital to be
22 successful. And those would be the first two reasons,
23 high mechanical risk and high cost. In fact, the
24 initial investment is a high cost. The actual
25 drilling cost is about three times that of a vertical

1 well, and to complete and set full facilities we're
2 about two, two and a half times the total cost.

3 The biggest disadvantage would be to spend
4 the capital to test this technique and find out we
5 cannot increase ultimate recovery over that that we
6 have with redrilling of just a vertical well.

7 Q. In your opinion, will the additional
8 surface of the formation contacted with the
9 highly-deviated well give you a direct relationship to
10 the deliverability of that well?

11 A. No, not just the contact area. The major
12 thing that will control any productivity, whether it's
13 a vertical or horizontal well, will be the
14 permeability of the formation. And just by the
15 increased contact area, we won't gain an advantage
16 production-wise, productivity-wise.

17 Q. Let's go to the analysis that you have on
18 page 7 of your exhibit book. You've been asked to
19 examine the Examiner Order that was entered in this
20 case. Have you done that, Mr. Dunn?

21 A. Yes, sir.

22 Q. Would you describe for us, in a simple way,
23 what it is that is the problem with the Examiner
24 Order?

25 A. Basically, by attempting to drill this

1 highly-deviated well, we've lost part of the allowable
2 calculation and we feel like this is not a good thing
3 to do when we're taking additional risk to drill this
4 well to try to increase ultimate recovery. From an
5 economic standpoint, this is a plat that helps to
6 support the increased rate that would be required from
7 a highly-deviated well just to break even with a
8 vertical well.

9 Q. Let's give them some background before you
10 talk about your analysis. What kind of cost factors
11 were you using for a vertical well?

12 A. The vertical well runs us about \$400,000
13 typically, to drill, complete and have facilities to
14 produce it down the line.

15 Q. What does it cost to drill the
16 highly-deviated well?

17 A. The highly-deviated well estimated cost at
18 this point is about \$990,000, almost a million.

19 Q. That's for drilling, completion and other
20 equipment?

21 A. Other facilities, right.

22 Q. When we look at the drilling portion of a
23 vertical well and compare it to the drilling portion
24 of the highly-deviated well, what magnitude of
25 difference is there?

1 A. You're talking about a little bit over a
2 three-fold increase just to drill the highly-deviated
3 well over that of a vertical well.

4 Q. In order to understand the economics by
5 which you then judge if the Examiner Order has given
6 you an adequate level of economic incentive for the
7 project, what did you do?

8 A. I performed a break-even analysis with some
9 basic assumptions to determine at what level the
10 highly-deviated well would have to produce to give us
11 a break-even factor and then, in addition, looked at
12 some cost-sensitivities later.

13 Q. Before you get to the conclusion, tell us
14 how to read the display.

15 A. This is a plot of initial gas rate on the X
16 axis against a net present value on the Y axis. What
17 I've done is sensitized initial rates for the
18 high-angle well, and that's the square dots and the
19 lines going through those. Basically it shows a net
20 present value and an initial rate. For the high-angle
21 well, as we get higher rates, higher net present
22 value.

23 In addition, what I've shown on here is the
24 net present value we can obtain from doing a new
25 vertical redrill, along with utilizing the in-fill

1 well, which would be the standard practice in the
2 proration units right now. That net present value is
3 the dotted line coming across to intersect the
4 highly-deviated well sensitivity. What it shows is
5 just to break even, without including any additional
6 risk, that we would have to have an initial rate of
7 2.7 times that of an average redrill well.

8 Q. Of the rate of an average redrill?

9 A. Correct, rate of an average vertical
10 redrill.

11 Q. Did you do any other kinds of analysis in
12 order to see what the incentive was required for the
13 project in terms of an allowable?

14 A. We, in addition to that, looked at cost
15 sensitivities because of the high risk to see at what
16 risk we were as a company. As we started increasing
17 cost, how much fold that increased the rate that we
18 had to get from the highly-deviated well.

19 Q. It's not Meridian's practice, nor anyone
20 else's practice in the industry, to your knowledge, to
21 simply drill wells to break even, is it?

22 A. No, and that's true, too. What we're
23 looking for is a situation to make more money than
24 that of a--especially in this case, a vertical well
25 that costs us half as much at the minimum, we would

1 need to do more than break even to move ahead with
2 this project.

3 Q. Your break-even analysis is predicated on a
4 highly-deviated well costing how much?

5 A. \$985,000.

6 Q. Have you studied to see what happens to
7 your economics if you're required to spend some
8 percentage in excess of that amount?

9 A. Yes, we've looked at increases in cost.

10 Q. Have you plotted that?

11 A. Yes, sir.

12 Q. Let's go to page 8. What have you done on
13 display page 8 that is different than what we found on
14 page 7?

15 A. Basically it's the same type of plot in
16 terms of the X and Y axis. In addition we plotted two
17 new sensitivity lines, one with the triangles and one
18 with the circles, and those are net present values
19 versus rate sensitivities for increased costs of 25
20 percent in the case of the triangles, and a 50-percent
21 increase in cost for the circles.

22 Q. What does the analysis show you?

23 A. The analysis indicates that you can see the
24 base case is still plotted on here, 2.7 times. If we
25 go to a 25-percent increase, which is the lines with

1 triangles, we end up with four to four and a half-fold
2 increase in rate that we have to get to again break
3 even. If we go to a 50-percent increase, it's going
4 to be greater than a six-fold increase in rate that we
5 have to get from a highly-deviated well to break even.

6 Q. Why don't you take your seat again. Do
7 you, Mr. Dunn, have any reservations as a reservoir
8 engineer having studied this particular project, that
9 the opportunity as afforded you with the drilling of
10 these pilot wells to recover reserves that might not
11 otherwise be recovered?

12 A. Yes, I believe that we can do that.

13 Q. Can you conclude, therefore, that approval
14 of this project will prevent waste?

15 A. Definitely, that if it is not moved forward
16 with, that reserves can be left in the ground.

17 Q. Let's address now the other portion of the
18 Commission's concern in any case, and that's
19 correlative rights. Do you have an opinion as to
20 whether or not the approval of this project, as we
21 propose to set the allowable and in place a cap on
22 that producing rate for the project, does that give
23 you an unfair advantage over Amoco or any of the other
24 operators?

25 A. No, it doesn't.

1 Q. Describe for us why not.

2 A. I believe it's a fair and equitable
3 solution to the deliverability problem, and that is
4 based on the fact that we are introducing a cap which
5 is the same as exists currently in the San Juan Basin
6 for vertical wells.

7 Q. Explain that to me, Mr. Dunn.

8 A. There exists proration units out there
9 currently with two vertical wells that we can base
10 this cap on, that we could also drill two new vertical
11 wells in either the Howell "E" 2 proration unit or the
12 Riddle, and potentially gain that same level of
13 production.

14 Q. Let's put you in Amoco's position. Would
15 you, as a reservoir engineer, have any objection if
16 Amoco was to put in place a pilot project as you're
17 proposing here and you're in the offset position?

18 A. No. I would gladly like to see them do
19 that so I can see the results of the study, also.

20 Q. Describe for us, if you will, the mechanics
21 of how you propose to put in place the special project
22 allowable by the use of the deliverability. And let
23 me have you begin at the beginning. Let's start with
24 an original Mesaverde well, under the proration
25 system, and tell me the mechanics of how that

1 producing rate is established for that well.

2 A. When the initial well is drilled in a
3 proration unit, the parent well, that well acts as the
4 only well to be calculated into the deliverability
5 calculation. It's run through a state deliverability
6 test, and based on that test a state "D" is arrived
7 at, which is a function of the productivity of the
8 well and draw down of the well, and that state "D" is
9 then entered into the allowable allocation-type
10 formulas, but only that one well would be included at
11 that point.

12 Q. Under the proration system in place for the
13 Mesaverde, then part of the formula is based upon the
14 deliverability or the capacity of the wells?

15 A. That is correct. Approximately 75 percent
16 is deliverability and 25 percent is acreage.

17 Q. For those spacing units that have exercised
18 the opportunity for an in-fill well in the spacing
19 unit, how then is the allowable calculated?

20 A. As soon as you drill the in-fill, it is
21 also taken into consideration in the same manner. The
22 tests are run, the two deliverabilities, state "D's"
23 that come from the two--now-existing two vertical
24 wells, are added together to give you a deliverability
25 for the total proration unit. Basically, it's

1 equivalent to having 160-acre proration units, even
2 though we're working on a 320 acre with in-fills.

3 Q. Does the Commission give you the
4 opportunity to produce that allowable out of either
5 well exclusively or in combination among the two
6 wells?

7 A. That's correct.

8 Q. What happens in those situations where we
9 have a third well in a 320-gas spacing unit for the
10 Mesaverde?

11 A. The standard practice in the two examples
12 that we showed are both that case, the Howell "D" 3B
13 and the Scott 2R. There is three active wellbores in
14 the proration unit, two in the north half and one in
15 the south half. In that case, when you drill the
16 third well, you can test all three wells. You have
17 the option of utilizing either of the two wells that
18 are in the same quarter section.

19 Q. Utilizing the deliverability of either of
20 those two wells?

21 A. The deliverability of either one of those,
22 but only one, and then the opposite quarter section
23 that only has one well, then you would add it in. So
24 you would use two out of the three wells, with one of
25 those coming from the portion that has two wells in

1 it.

2 Q. What options or alternatives did the
3 Examiner Order provide to you in setting the allowable
4 for the spacing unit?

5 A. With the highly-deviated well?

6 Q. Yes, sir.

7 A. With the highly-deviated well, the ruling
8 was that we could use one times the "D" of the
9 highly-deviated well, or add the two vertical wells
10 together to get our total deliverability. So,
11 basically, we lost at least one well out of the
12 standard practice.

13 Q. Why do you need twice the deliverability of
14 the deviated well in order to have an economic
15 incentive for a special project allowable to let you
16 go ahead with the project?

17 A. Twice the allowable reduces some of the
18 risk that we're taking, and gives us an incentive to
19 move forward and attempt to drill this project. In
20 addition, this is a wellbore that crosses--covers,
21 basically, the full 320 acres due to its
22 highly-deviated nature, and therefore it's covering
23 the full 320 acres and could act as two wellbores.

24 Q. Does doubling the "D" for the deviated well
25 give you an unfair competitive advantage over the

1 offsetting operators?

2 A. No, I do not feel it does, because again
3 the productivity of the well is primarily a function
4 of the permeability within the formation, reservoir
5 pressure and some other things. In this case we're
6 attempting to find higher permeability regions,
7 additional reserves within our own proration unit, and
8 it is not a function solely of the shape of the
9 wellbore, and the two "D" would, again, assist us in
10 reducing our risk up front.

11 Q. Why can't you go ahead with the pilot
12 project, get your wells drilled and come back after
13 the fact when we know what the producing rates or the
14 capacities of these wells is going to be and then set
15 an allowable for the spacing units?

16 A. At that point we would have judged the
17 economics of the project up front on one assumption,
18 and then the assumptions could change down the road
19 and we would end up with potentially an uneconomic
20 project that we've built on.

21 Q. Have you considered whether or not there is
22 an unfair competitive advantage that your project will
23 enjoy over the offsetting properties in terms of
24 drainage?

25 A. The drainage concept from the

1 highly-deviated well would be very little different
2 from a vertical well, and that is, a vertical well has
3 a radial drainage that is currently of whatever
4 radius.

5 When you drill the highly-deviated well,
6 you still have similar drainage radius, but that
7 drainage radius is moving down the length of the
8 proration of the drilling window, so what you're
9 ending up with is sort of a tilted cylinder coming
10 down the proration unit. Your radius is not going to
11 change unless you intercept enhanced permeability
12 areas or something like that. It won't change just
13 because of the deviated nature of the wellbore.

14 Q. Do you have an opinion, Mr. Dunn, as to
15 whether or not, if the Commission grants Meridian's
16 request to have twice the deliverability put into the
17 order, that that, in your opinion, will allow the
18 project to continue?

19 A. Yes, we would definitely continue with
20 that.

21 MR. KELLAHIN: I have no further questions
22 of Mr. Dunn.

23 CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

24 MR. KELLAHIN: Perhaps it's proper at this
25 time to move the introduction of Exhibit 1, pages 1

1 through 8, Mr. Chairman.

2 CHAIRMAN LEMAY: Without objection,
3 Exhibits 1 through 8 will be admitted into the
4 record. Mr. Lund.

5 MR. LUND: Thank you, Mr. Chairman.

6 EXAMINATION

7 BY MR. LUND:

8 Q. Good morning, Mr. Dunn. Let's first turn
9 to page 3 of your exhibit book, please.

10 A. Let me get an exhibit book. Okay.

11 Q. That's a depiction of state deliverability
12 data, is that correct?

13 A. That's correct.

14 Q. For the Howell area?

15 A. That's correct.

16 Q. Do you have any cumulative production
17 information from the proration units in that area?

18 A. Yes.

19 Q. Do you have that in front of you or do you
20 need to refer to something?

21 A. No, I would have to refer to something.

22 Q. Let me ask you this generally. In the
23 center of Exhibit No. 3, you've got the Howell unit
24 highlighted. Do you know what its cumulative
25 production is?

1 A. Approximately 14 Bcf, I believe.

2 Q. What about the cumulative production just
3 to the east of that, the proration unit in the west
4 half of Section 13?

5 A. West half of Section 13? I couldn't tell
6 you that one without looking up the data.

7 Q. Do you have the data available? My data
8 indicates it's 5.2 Bcf?

9 A. That sounds in the range.

10 Q. Does that sound reasonable to you?

11 A. Uh-huh. Uh-huh.

12 Q. What about the cumulative production to the
13 west of the Howell unit also in Section 14, the
14 Florance unit?

15 A. I don't have the exact data. It's greater
16 than 10 Bcf, I believe.

17 Q. How about 10.9 Bcf?

18 A. That sounds about right.

19 Q. So already in Section 14 you've got the
20 Howell proration unit already producing 4 Bcf greater
21 than the offset to the west, is that right?

22 A. That's correct.

23 Q. Let's go to the south of the Howell unit,
24 going to Section 23. Do you know what the cumulative
25 production is in the proration unit in the east half

1 of Section 23?

2 A. Not exactly, probably a little bit greater
3 than 10, again, I would assume.

4 Q. How about 5.3 Bcf? Does that sound true to
5 you?

6 A. I would have to look at that one. I don't
7 know.

8 Q. And the proration unit in the west half of
9 Section 23, the Howell one, do you happen to know what
10 the cumulative production is there?

11 A. No.

12 Q. How about 7.9 Bcf?

13 A. That's reasonable.

14 Q. Does that sound in the ballpark to you?

15 A. Yes, it does.

16 Q. Finally, let's look at the proration unit
17 in the west half of Section 24. Again, do you happen
18 to know what the cumulative production is there?

19 A. No.

20 Q. How about 5.2 Bcf? Does that sound
21 reasonable to you?

22 A. It could be.

23 Q. Does it sound reasonable, though?

24 MR. KELLAHIN: I'm going to object unless a
25 foundation has been placed for this witness to say.

1 I don't want him to guess. If Mr. Lund has a witness
2 who can give us the cum's, let's put him on. But if
3 this witness doesn't know, it's not fair to have him
4 guess.

5 CHAIRMAN LEMAY: I would agree with that.
6 That's normally the subject of your own witness. "What
7 is reasonable," I don't know what you're trying to get
8 at.

9 MR. LUND: I would be happen to live with
10 the ruling, Mr. Chairman, but he did testify that he
11 was generally familiar with the cumulative production
12 in the area.

13 CHAIRMAN LEMAY: Generally familiar with
14 it, without knowing specifically what the offset tract
15 does.

16 MR. LUND: Maybe I could just ask one
17 question and move along.

18 CHAIRMAN LEMAY: Okay.

19 Q. Isn't it fair to say, Mr. Dunn, that the
20 Howell unit that you were discussing has produced
21 approximately 14 Bcf? That's already considerable
22 greater than those offsets we've been discussing,
23 isn't that fair to say?

24 A. It's fair to say for the ones you've
25 discussed, that's true.

1 Q. And you were talking earlier about the
2 competitive advantage of some of these offset wells.
3 I just don't see that existing, given those cumulative
4 production figures.

5 MR. KELLAHIN: Objection. That's
6 argumentative.

7 CHAIRMAN LEMAY: Can you rephrase the
8 question, Mr. Lund?

9 MR. LUND: The witness testified about a
10 competitive advantage to the offsets of this
11 particular drilling unit. I'm asking him how he can
12 say that, given these cumulative production figures.
13 I don't think that's argumentative.

14 CHAIRMAN LEMAY: Rephrased that way it's
15 not. Continue.

16 Q. Would you answer that question, please, Mr.
17 Dunn?

18 MR. KELLAHIN: Do you remember the
19 question?

20 A. Could you rephrase it?

21 Q. Sure. Given the cumulative production
22 figures we've been discussing, it appears that the
23 Howell proration unit's cumulative production of
24 approximately 14 Bcf is considerably greater than the
25 other proration units we just went through. Is that a

1 fair statement?

2 A. It's a fair statement that it is greater.

3 Q. Is 4 Bcf considerably bigger than
4 production from an offset unit?

5 A. I think it depends on the area and what the
6 ultimate recoveries are.

7 Q. All right. You don't think 4 Bcf is
8 considerably greater. My question is, how can you say
9 that the Howell unit, which is in the center of your
10 Exhibit No. 3, is suffering a competitive
11 disadvantage, vis-a-vis offset proration units, when
12 it's cum'd 4 Bcf greater than the other offsets?

13 A. It's based on the fact that we produce at
14 about half of our maximum rate than any of the offsets
15 and, in many cases, a great deal less than half.

16 Q. So you have the current deliverability
17 figures? Do you have the current deliverability
18 figures of the offsetting units in front of you?

19 A. Exhibit No. 3 that you referred to earlier
20 is that exhibit, the most current that I have
21 available to me.

22 Q. Let's talk about those. Is that from
23 February of 1990? Is that where those deliverability
24 figures come from?

25 A. No. In most cases all these--well,

1 anything that we do not operate, I do not have access
2 to any of the latest tests. Those all came out of the
3 1986 state deliverability books.

4 Q. 1986?

5 A. That's correct.

6 Q. Well again, looking at some of these
7 offsets, let's look at the offset to the east in the
8 west half of Section 13. Do you know what the current
9 deliverability there? or even the 86 data I would
10 accept.

11 A. For the proration unit for the east half?

12 Q. For the west half of Section 13, which is
13 immediately offset to the east.

14 A. Approximately 875 Mcf a day.

15 Q. That's what my figure is, too. How about
16 the proration unit for the west half of Section 24?

17 A. Approximately 600--over 600.

18 Q. That's fair. That's consistent with my
19 data, too. How about the proration unit for the east
20 half of Section 23, which is directly to the south of
21 the Howell unit?

22 A. Approximately 700 Mcf a day.

23 Q. That's fair, also. How about the proration
24 unit in the west half of Section 23?

25 A. Almost 400.

1 Q. 386?

2 A. That's correct.

3 Q. And then finally the proration unit
4 directly to the west of the Howell unit, that being
5 the Florance unit?

6 A. Oh, about 1.4 million a day.

7 Q. Again, my question goes to the competitive
8 disadvantage that you stated that the Howell proration
9 unit is currently suffering. You've got
10 deliverability figures of offsetting proration units
11 that are considerably less than what's the Howell's
12 doing, don't you?

13 A. No. The deliverability of the Howell unit
14 currently is 520 Mcf a day. Also, we haven't looked
15 at all the acreage around it, of course, but in
16 general you named one proration unit that had anywhere
17 less deliverability, according to my calculations.

18 Q. What's the number, the 186 number for the
19 Howell "E" 2? Where does that come from?

20 A. That's the current test for the
21 Howell "E" 2.

22 Q. As of what date?

23 A. Middle of last summer it was tested.

24 Q. The information I have is at 4/28, but I
25 don't know if that's current.

1 A. No, it's not.

2 Q. It's lower than that?

3 A. Correct. The 186 is the current test.

4 Q. All right. I think in your testimony you
5 stated that you were to honor the 790 setbacks for the
6 deviated well, is that correct?

7 A. That's correct.

8 Q. You would file deviation surveys with the
9 OCD to make sure that it doesn't encroach on the 790
10 setback?

11 A. That's correct. That's all in the initial
12 order that we said we accepted.

13 Q. You haven't changed that position?

14 A. No.

15 Q. Where are you going to perforate and
16 produce the deviated wellbore in the Howell unit?

17 A. We won't know until we drill the well. .
18 We'll drill as far through the Mesaverde interval as
19 we can, while staying within that drilling window, and
20 we hope to be able to produce all that is productive
21 within that interval.

22 Q. If it only looks productive in that one
23 quarter section that the deviated wellbore encounters,
24 would you only perforate and produce from that one
25 quarter section?

1 A. If that was the case. We expect to be
2 productive throughout, since we have wells in the
3 north and south end that produce.

4 Q. I think you're talking about, you've got to
5 look for increased permeability areas and additional
6 sand lenses that you haven't encountered with the
7 vertical well, is that right?

8 A. We hope to find those situations when we
9 drill this well, yes.

10 Q. My question is, if you only encounter
11 additional sand lenses and increased permeability in
12 one quarter section that the deviated wellbore
13 encounters, would you then just complete and produce
14 only in that quarter section?

15 A. No, we would not. This is part of an
16 overall idea to redrill the original well and to
17 produce from throughout the Mesaverde formation.

18 Q. Let me ask you a couple of questions about
19 the well costs. I think you testified that a vertical
20 well would cost about \$400,000, is that right?

21 A. To drill, complete and have facilities.

22 Q. And for a deviated wellbore, approximately
23 \$1 million?

24 A. Yeah. \$985,000 is what I utilized in the
25 economics.

1 Q. I was looking at the transcript from the
2 prior hearing, and your drilling engineer--I believe
3 his name is Mr. Falconi?

4 A. That's correct.

5 Q. --gave some figures about well costs, and
6 they're different. I was just curious, were Mr.
7 Falconi's figures not including facilities and things?

8 A. Facilities or completion. He, as I
9 remember--and I don't have the transcript in front of
10 me--was stating drilling costs. Basically, rough
11 numbers, we can drill a vertical Mesaverde for about
12 \$200,000 and it will cost \$6- to \$700,000 to drill the
13 highly-deviated.

14 Q. Those were the figures I was remembering.

15 A. That's right.

16 Q. The difference again is what, the
17 completion facilities?

18 A. Completion and facilities are an additional
19 plus or minus \$200,000.

20 Q. Let's talk a little bit about the
21 correlative rights issue and that's the only reason
22 Amoco is here. That's what we've got concerns about.
23 We think it's a great idea to do this technology.

24 I think you testified earlier that under
25 the formula you proposed, the offset operators'

1 correlative rights are going to be protected, is that
2 right?

3 A. Today?

4 Q. Yes, sir.

5 A. Yes, that's correct.

6 Q. And I think you also testified that two
7 vertical wells could very well give you the same
8 protection as one of these deviated wellbores? Is
9 that right?

10 A. No. What I testified was that the greatest
11 that you're at risk for right now is what two vertical
12 wells currently produce within the Blanco-Mesaverde
13 Field. So we would cap it at that level.

14 Q. You haven't discussed what the cap would be
15 yet, have you? Are you going to talk about that?

16 A. I can give you rough numbers to my
17 knowledge what that cap is, what the highest
18 deliverability in a proration unit is.

19 Q. You proposed some language for inclusion in
20 the order which was a little bit different than what
21 the Examiner had. Can you explain that?

22 A. It just requests that the cap be the
23 highest state deliverability in a proration unit in
24 the Blanco-Mesaverde Field.

25 Q. So you would look at just a traditional

1 proration unit in the field and calculate the
2 deliverability based on the two existing vertical
3 wellbores, and whatever the highest is in the field,
4 you would limit your deliverability to that?

5 A. That would be the cap, that's correct.

6 Q. Do you happen to know what the highest
7 deliverability is currently for a traditional
8 proration unit?

9 A. I think it's in the range of 16 million a
10 day.

11 Q. What proration unit is that?

12 A. It's the Fields 2 and Fields 2A, and I
13 can't give you the exact location. It's in 39, I
14 believe. But I can get that for you.

15 Q. We would like to see that.

16 MR. KELLAHIN: May I approach the witness,
17 Mr. Chairman? I can give him that location.

18 A. The Fields LS #2 and #2A wellbores are
19 located in Township 32 North, Range 11 West, Section
20 25. It's operated by Amoco and it currently has a
21 State "D" of 16,061,000. It would be 16 million.

22 Q. You would tie to whatever the then current
23 deliverability is? If that goes up or down, you would
24 tie it to that?

25 A. We would consider that stipulation, yes.

1 Q. I'm sorry, I don't understand.

2 A. At this point we're just suggesting the tie
3 to this state deliverability, to this current one.

4 Q. What happens if the deliverability in that
5 unit you referenced goes up or down?

6 A. It goes up or down, then.

7 Q. Would your deliverability in your unit go
8 up or down accordingly?

9 A. It could. Are we talking in comparison,
10 utilizing this data?

11 Q. What's your proposal, is what I'm asking.

12 A. Our proposal is to set our cap at this
13 current highest proration unit deliverability.

14 Q. So it wouldn't change? It would stick at
15 the 16 million?

16 A. That's the proposal, but it could change.
17 We think the most fair and equitable proposal is to
18 tie to this cap currently. As production decreases in
19 any of the units, it's going to decrease in our unit
20 for the same reason as reservoir pressures decrease,
21 et cetera, as you produce reserves.

22 Q. We're talking about your proposal for
23 deliverability in allowable calculations. That's what
24 I'm trying to understand. You're going to set it at
25 the 16 million and it's not going to change for your

1 units?

2 A. I think that's fair and equitable.

3 Q. I don't, but I just want to understand what
4 your proposal is.

5 MR. KELLAHIN: Objection to the editorial
6 comment, Mr. Chairman.

7 CHAIRMAN LEMAY: I agree.

8 MR. KELLAHIN: We get lots of flexibility
9 before the Commission, but I object to that comment.

10 CHAIRMAN LEMAY: We do recognize the fact
11 that lawyers are incompetent. If they wish to
12 testify, they need to be sworn in.

13 MR. LUND: That's a well-known fact in the
14 Commission's proceedings.

15 A. I don't know that it's unfair to discuss
16 fluctuating up and down, though. I understand your
17 concerns.

18 Q. Thank you. The current system now, as set
19 up in the prorated pool rules, is that you look at
20 deliverability from wells in the opposite quarter
21 section, correct?

22 A. Could you rephrase that?

23 Q. You were talking about how you do the
24 formula for establishing deliverability. Mr. Kellahin
25 took you through about how you look at wells in

1 opposite quarter sections and then you add those two
2 together, isn't that right?

3 A. Correct. You would take the two existing
4 wells in the proration unit and add them together.

5 Q. We don't have any situation in the field
6 now where you've got a wellbore that goes through both
7 quarter sections, do you?

8 A. No, we don't. That's why this is a pilot
9 project.

10 Q. And it's a different situation?

11 A. Definitely.

12 Q. Final question about drainage. I think you
13 testified earlier that you don't see a problem of
14 drainage going out of your proration unit and draining
15 nearby proration units, is that right?

16 A. Yes. I testified, as compared to a
17 vertical well that could be drilled in this same
18 proration unit, that the drainage radius should be
19 similar at whatever location you want to speak about.

20 Q. So the wellbore encounters, what, two to
21 three times the formation?

22 A. That's right.

23 Q. But it's not going to increase its drainage
24 area in that section?

25 A. Radius. I guess the best example to

1 explain that would be if you were looking at vertical
2 wells, an example would be that if you took a stack of
3 pennies, let's say, and that stack of pennies
4 represented the drainage radius of that vertical well,
5 the well being in the middle of the stack of pennies.
6 Well, when you took that vertical well and redrilled
7 it as a highly-deviated well, what would happen, those
8 pennies would be slanted. They would start stacking
9 one on top of each other, and you would have a
10 drainage radius moving longitudinally down this
11 proration unit that's the same radius. It's just this
12 stack of pennies.

13 Q. And again, I think Mr. Kellahin asked you
14 this question: Meridian is not open to the
15 possibility of coming back and reviewing a potential
16 deliverability or an allowable situation, depending on
17 the results of this deviated well?

18 A. I think the rules are that at any time
19 anybody can propose that we come back and hear them,
20 and we would come back, if it's proposed to come
21 back.

22 MR. LUND: That's all I have.

23 CHAIRMAN LEMAY: Additional questions of
24 the witness? Mr. Weiss?

25 EXAMINATION

1 BY MR. WEISS:

2 Q. One thing you didn't tell us. What do you
3 forecast out of that well?

4 A. It's hard to forecast, and that's why we're
5 doing it as a pilot project. The reason why, the
6 permeability changes are drastic within the Mesaverde
7 and the nine-section deliverability plat that we
8 showed.

9 If you'll notice, there are ranges of
10 deliverability from 200 Mcf a day all the way up to 12
11 million a day within a half a mile, so it's tough to
12 forecast. We do not perceive that we are going to
13 gain a high productivity advantage over a good
14 vertical well that intercepts the same reservoir that
15 this highly-deviated well is in.

16 Q. 12 million is what you're anticipating? Is
17 that what you're saying?

18 A. Oh, no. I'm hoping to be able to get two
19 to three times the rate to make it an economic
20 project. But that's why we're drilling it to find
21 out. In addition, the more important factor is that
22 we also prove up additional reserves.

23 Q. How does that, let's say, two to three
24 times, I still don't have a number for you. Give me a
25 number, any number. I don't care. What do you think

1 it's going to be? 500,000 a day? a million? two
2 million?

3 A. No. I would guess greater than a million
4 for sure, because we're getting--

5 Q. How does that compare to a well that's has
6 a massive fracture treatment up in this area?

7 A. Most of the redrills that we're doing right
8 now, which we do do massive hydraulic fractures,
9 produce one to one and a half million a day. The
10 examples that we showed of the Howell "D" 3B and the
11 Scott 2R are greater than three million a day.

12 Q. On your P/Z charts, were those redrills
13 stimulated in the same manner as the first well?

14 A. No, they would be hydraulically fractured,
15 where the original ones would have been nitro-type
16 open-hole.

17 Q. I notice also you're drilling them both
18 towards the south?

19 A. That's only because the original, the old
20 well, is in the north. We would drill to the north or
21 to the south--

22 Q. Why not east/west at some place?

23 A. Primarily due to--if we go east/west and
24 stay within our drilling window, we lose--well, I
25 don't know what that would be.

1 Q. On these leases, but surely there are some
2 where you could drill east/west 3,000 feet, if you
3 wanted to. I'm just curious.

4 A. If that situation existed, we would
5 definitely take that into consideration.

6 Q. As you test these wells, is it possible to
7 test the pressure in each individual plot pod or lands
8 as you call them? I'm just curious if there's
9 anything to support the fact that there's no flow
10 across pod barriers, such as you've assumed, or these
11 lens--

12 A. The only support, and we'll kind of talk
13 about this a little later, or somebody else will, that
14 I have in my hands right now, one of the two redrills
15 that we did, prior to redrilling it, produced
16 condensate. And after drilling it we came in with
17 what is really oil. It changed from like a 49-degree
18 gravity down to in the 35 to 40 range. So, we picked
19 up a pod of oil that wasn't in the first one.

20 Q. Then on your economics here, I didn't pick
21 up what the price of gas is going to be.

22 A. I used--well, it doesn't really matter
23 because these are incremental, basically, economics.
24 I'm showing a break-even point.

25 Q. I understand, but it has a great deal to do

1 with that break-even point.

2 A. No, because they're incremental to each
3 other.

4 Q. Well, any break-even point, I think, is
5 fixed, and depending on the price of gas and what it
6 cost to drill the well--

7 A. It would fluctuate somewhat. I ran
8 sensitivities on gas prices and some other things, and
9 basically the point of the exhibit is not to show that
10 2.7 is exactly the break-even point. There's lots of
11 assumptions that could be maneuvered, including the
12 initial rate of the vertical well. The point of the
13 economics is to show that we have to have a drastic
14 increase in rate, whether it's two-fold, three-fold or
15 four-fold, to make this an economically viable project
16 for us.

17 Q. And the price you used on that graph?

18 A. That was SEC pricing that we use for--

19 Q. I don't know that what an SEC price is.

20 A. I'm trying to remember that right now.
21 It's flat pricing, and I'm trying to remember it.
22 It's something like \$1.60 an Mcf.

23 Q. On your figure 3, down in Section 22--

24 A. Yes, sir.

25 Q. --I see the deliverabilities of those wells

1 are quite high?

2 A. That's correct.

3 Q. Were they completed differently than your
4 low permeability wells wells, do you know?

5 A. I can't speak specifically on that. In
6 general, the wells such as in Section 22, the Florance
7 45, is probably an older well and would not have an
8 identical hydraulic frac stimulation as the Florance
9 45A did.

10 I guess the answer to that is, I can't
11 speak totally on that. The open-hole wells that were
12 drilled in the 50's would be drastically different
13 from newer wells which were hydraulically fractured.
14 So, depending on the age of the well, there would be
15 differences.

16 MR. WEISS: That's all I can think of at
17 this moment. Thank you.

18 EXAMINATION

19 BY CHAIRMAN LEMAY:

20 Q. Mr. Dunn, it looks like you're going
21 northwest to southeast with that, or is that because
22 that section is tilted? I'm trying to understand if
23 you're going straight north/south in the section or
24 taking some kind of an angle?

25 A. What we're depicting there is a due south

1 line. That's because that section is tilted a little
2 odd. The wellbore that's depicted there is due south.

3 Q. I have the same concern on your prices that
4 Commissioner Weiss had. Maybe a subsequent witness
5 will touch on some economic scenarios there. What
6 you're trying to show, as I understand it, is a
7 deviated hole is going to cost more; therefore, you
8 need an incentive allowable to justify drilling? Is
9 that right in a qualitative sense, not necessarily
10 quantitative?

11 A. That's right, along with to help with the
12 risk that we see in drilling the well.

13 Q. The risk, as you're explaining it, is
14 financial risk of the cost of the wellbore, as well as
15 any contingencies that you might run into?

16 A. It's a combination of that risk and the
17 risk that we will not increase recovery, that we've
18 gone out and spent an extreme amount of capital for a
19 project that ends up being uneconomic. That's what
20 we're trying to prove about the new technique.

21 Q. Do you plan to frac that well?

22 A. It depends. In the Mesaverde, if the
23 productivity isn't high enough you definitely go in
24 and fracture. There are wells that do not have to be
25 fractured to produce.

1 Q. But the diagonal well, is the technology
2 there any different from fracking a diagonal well than
3 a vertical well?

4 A. Yeah, it's different, and it would cost
5 more again. And that is not included in these cost
6 estimates, but, yes, it would cost more and is more
7 difficult to do.

8 CHAIRMAN LEMAY: Mr. Weiss?

9 MR. WEISS: I have one more.

10 FURTHER EXAMINATION

11 BY MR. WEISS:

12 Q. Were there incentives provided to do
13 massive frac jobs on these newly drilled vertical
14 wells?

15 A. Not that I'm aware of, no.

16 Q. Then, I, frankly, don't see a hell of a lot
17 of difference between a massive frac, where you spend
18 maybe a million dollars on a frac job, and this.

19 A. That comparison, in fact, I utilized in the
20 first hearing. There is some truth in that. That's
21 why we feel like the original ruling is unfair because
22 it's less than even the current standards.

23 What we are proposing, what is fair and
24 equitable to us, first of all, is that that first
25 ruling is not fair and equitable, and second of all,

1 the two times the "D" is a reasonable request based on
2 that this well would roughly develop the full 320
3 acres.

4 Q. Here is looks to me like you have control
5 of your fracture and maybe you wouldn't the hydraulic
6 fracture, the direction of it. And the costs are,
7 maybe, comparable between this and a massive hydraulic
8 fracture?

9 A. I couldn't really speak on that. I would
10 think this is more expensive in the long run, really,
11 and also I guess the rest of the theory in terms of
12 why we would want to do a highly-deviated well versus
13 just go out and do a massive hydraulic frac, is that
14 that fracture is going to go one direction, basically,
15 and what is the chances of that fracture hitting
16 versus us doing this, you know, longer-reach wellbore.

17 Q. Here you have control?

18 A. Right.

19 MR. WEISS: Thank you.

20 CHAIRMAN LEMAY: Additional questions of
21 the witness? If not, he may be excused.

22 Let's take a 15-minute break.

23 One additional thing. Mr. Lund, you won't
24 present testimony or statements in the case?

25 MR. LUND: Sounds like maybe we have to,

1 given the production data.

2 CHAIRMAN LEMAY: Well, I think we can
3 understand your position. Our concern is that without
4 any of the witnesses, we have no counter proposal from
5 Amoco as to what the formula should be. And actually
6 that would be helpful if you're opposing the case.

7 MR. LUND: We would be happy to do that.

8 CHAIRMAN LEMAY: Thank you.

9 (Thereupon, a recess was taken.)

10 CHAIRMAN LEMAY: We shall continue. Mr.
11 Kellahin.

12 MR. KELLAHIN: Thank you, Mr. Chairman. At
13 this time I would like to call Mr. Greg Jennings. Mr.
14 Jennings is already under oath as a witness. He's a
15 petroleum geologist with Meridian in Farmington.

16 GREG JENNINGS

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

19 EXAMINATION

20 BY MR. KELLAHIN:

21 A. For the record, Mr. Jennings, would you
22 please state your name and occupation?

23 A. My name is Greg Jennings. I'm a senior
24 geologist for Meridian Oil in Farmington, New Mexico.

25 Q. Mr. Jennings, have you participated as a

1 petroleum geologist for your company in this study
2 group of technical people to evaluate the feasibility
3 of a highly-deviated wellbore in the Mesaverde
4 prorated gas pool?

5 A. Yes, I have. George Dunn and myself and a
6 few other people have worked on this for 9 or 10
7 months.

8 Q. Did you testify before Examiner Catanach in
9 the Examiner Hearing of this case?

10 A. Yes, I did.

11 Q. You presented to him your geologic
12 interpretations and conclusions in that manner?

13 A. That's correct.

14 MR. KELLAHIN: Mr. Chairman, at this time
15 we would tender Mr. Jennings as an expert petroleum
16 geologist.

17 CHAIRMAN LEMAY: His qualifications are
18 acceptable.

19 Q. Mr. Jennings, I'm not going to ask you to
20 repeat all your geologic interpretations and
21 conclusions that you presented to the Examiner, but I
22 would like you to give us a clear understanding of the
23 geology, as you interpret it, with the Mesaverde
24 reservoir in this pool, and explain to us why you, as
25 a geologist, conclude that the pilot project for these

1 two wells is a necessary project.

2 A. Well, the first exhibit, which is a
3 cross-section A to A', I'll actually illustrate a
4 couple of points from this exhibit. As you're all
5 aware, the Blanco-Mesaverde pool was originally
6 developed in the 1950s on 320-acre spacing, and then
7 in-filled in the 70s on basically 160's. There really
8 is a drastic difference in the drilling and completion
9 techniques used for the old wells versus the new
10 wells. You can visually see it on this
11 cross-section. The cross-section--

12 MR. KELLAHIN: Excuse me. It should be
13 page 9 of the exhibit book.

14 MR. WEISS: They're mislabeled. This says
15 B to B'.

16 MR. STOVALL: Your exhibit says B to B'.

17 THE WITNESS: I'll have to take that up
18 with the drafting department when I get back.

19 Q. All right, Mr. Jennings. Continue.

20 A. This is a north/south cross-section through
21 the Howell section, it's Section 14 of 30 North, 8
22 West. It includes the old well drilled in the 1950s,
23 the Howell "E" 2, and two wells drilled in the 1970s.
24 The old drilling method was to drill right to the top
25 of the massive Point Lookout, TD the well, set

1 production casing to the lower part of the Cliff
2 House, the massive Cliff House, and generally they
3 completed these wells, open-hole, with nitro.

4 The new wells, as you can see, drilled 3-
5 to 400 feet deeper in the Lower Point Lookout, set
6 production casing through the entire section, and then
7 a two- to three-stage frac perfed and stimulated the
8 entire section. You've got significant interval that
9 was not completed in the original well, in the older
10 wells, and furthermore the inefficient stimulation
11 that was done in the 1950's gives you a basic inequity
12 between the wells that are drilled in the 70's and the
13 wells that are drilled in the 50's.

14 This really is the basis for our Mesaverde
15 redrill program. We recognize that those old
16 wellbores are not adequately draining their spacing
17 units, and George can--well, George has discussed that
18 already. It's a function of the way the wells are
19 drilled and completed, but it's also a function of the
20 variability in the reservoir quality, and the
21 cross-section shows that.

22 Basically, I've colored the sandstone pay
23 greater than six percent density porosity,
24 standardized it to a 25-zone resistivity cutoff where
25 resistivity logs are available. You have a net pay

1 map, a little one on the cross-section, and if that
2 will work, that will speed things up by not getting
3 into the bit net pay map.

4 The only thing I really want to show you
5 here is that there is significant variation in matrix
6 porosity over short distances. I believe the range on
7 this map is from a low of 130 feet to a high of 182
8 feet in total net pay in the Mesaverde group, and that
9 consists of multiple thin sandstone lenses that
10 blossom and pinch out from well to well.

11 Q. Let's look at the net pay map for a
12 moment. When you look at the net pay map, are you
13 mapping the net pay with a porosity value greater than
14 six percent for the entire Mesaverde pool interval?

15 A. Yes.

16 Q. When you look at the individual lenses that
17 make up the Mesaverde formation on the stratigraphic
18 cross-section, can you correlate each of those lenses
19 that have porosity values of six percent or greater
20 from wellbore to wellbore?

21 A. No. Certainly some are continuous, but,
22 for the most part, there's a lot of discontinuity.
23 It's a very heterogeneous reservoir.

24 Q. When you look at the relationship of the
25 original well and the in-fill well in the Howell

1 spacing unit, what do you conclude as a geologist with
2 relation of the availability of the in-fill well to
3 encounter and therefore potentially produce reserves
4 that are not exposed in the wellbore of the original
5 well?

6 A. I believe that there are additional sand
7 lenses, if you will, between the two in-fill
8 wells--between the two wells in the proration unit
9 that have not been penetrated and are not in
10 communication with the two wells in the unit.
11 Therefore, they do not completely drain all of the
12 reserves within that 320-acre unit.

13 Q. Are you, as a geologist, confident that you
14 can map the Mesaverde lenses between those two wells,
15 that you're going to know in the absence of drilling
16 the highly-deviated well, whether or not you're going
17 to get additional reservoir out of the Mesaverde?

18 A. Well, I'm confident that I cannot predict
19 with accuracy the degree of variability from one end
20 of the section to the other end.

21 Q. Can you, with confidence, map the wells in
22 the spacing unit with wells off the spacing unit?

23 A. Not to the degree of accuracy that we need
24 to figure out where all the pay is. It's really even
25 further exemplified, if we could move to this next

1 exhibit, which is basically the same thing, a
2 cross-section and net pay map for the Riddle area,
3 which is the other cross-section in your book, it's
4 even a more drastic exemplification of what's going
5 on.

6 Here we have variations in net pay from a
7 thin of 112 feet to a maximum of 275 feet in a little
8 over a mile. I was even surprised when I put this
9 together. I think it's quite obvious that we have
10 large variations in matrix porosity from well to
11 well. This doesn't tell the whole picture.

12 Number one, you have some drastic
13 variations in net thickness and in the continuity of
14 the reservoirs. But this doesn't correlate on a
15 one-to-one basis, by any means, with the drastic
16 variations in production. There are wide variations
17 in production in these wells out here, and it's more a
18 function of the lateral changes in permeability. This
19 is a fracture-enhanced reservoir, and all I can map
20 from logs is matrix porosity. And the fractures, and
21 those areas of higher permeability are the real key to
22 the enhanced productivity. It's quite common to find
23 some of the thinner net pay wells with the best
24 production.

25 Q. What do you, as a geologist, hope to gain,

1 that you don't already have, with the information that
2 results from drilling and completing the
3 highly-deviated wellbores?

4 A. Well, I believe that, and really it's been
5 proven, that there are these regions of
6 fracture-enhanced permeability that exist sometimes
7 very close to the existing wellbores. Two cases in
8 point George has already touched on. One was the
9 Scott 2R. We had a Mesaverde well that was completed
10 in the 50's, had cumulative production of roughly 3
11 Bcf in 30 years.

12 Another well, the Scott 2R, was drilled 2-
13 to 300 feet from that old wellbore. It took a kick in
14 the Upper Cliff House and the well came on line for 10
15 million a day and cum'd 6 Bcf in five years. So, in
16 five years that new well had cumulative production of
17 twice what that old wellbore had in 30 years. That
18 well is still making four million a day. Just from a
19 rate standpoint, it's pretty obvious that that well
20 encountered some new reservoir.

21 The other case was the Howell "D" 3B, which
22 here we had an old Mesaverde well drilled and
23 completed in the 50's that had cum'd 12 Bcf and 10,000
24 barrels of condensate, 50-degree gravity. Actually,
25 it was a Dakota test drilled 300 feet from the old

1 wellbore. They took a kick in the Lower Point Lookout
2 and TD'd the well there and completed it in the
3 Mesaverde, put it on line for four million cubic feet
4 a day, and 100 barrels of oil. Now we had 30-gravity
5 oil. In addition, high reservoir pressure. These are
6 2- to 300 feet away from the old wellbore.

7 So we know that there are these areas out
8 there that have additional pay, fractures, pockets of
9 higher permeability. But I can't map them. We could
10 drill 5 or 10 vertical wells in this section and we
11 may get lucky and tap into it as those two examples
12 did. But the odds are that we won't. This, really,
13 is the whole crux of the high-angle project. We know
14 that those regions are out there in our proration
15 unit. We know that the existing two wells, in all
16 likelihood, will not drain the reserves that are in
17 that spacing unit. Therefore, you have waste
18 occurring, and we think this technique will
19 significantly increase the chances of encountering
20 those fractures in those regions of higher perm simply
21 by exposing a much larger amount of surface exposure
22 to the rock.

23 Basically, what went to do is find those
24 areas that other people have found by good fortune; we
25 want to find them by design. We believe that if we

1 initiate this project and are mechanically successful,
2 which is by no means a guarantee. It's never been
3 done in the Western United States and only, I believe,
4 two in the whole U.S. If we are successful, we
5 believe that we will tap into those additional
6 reserves and basically increase the ultimate recovery
7 from the proration unit and prevent the waste that
8 will occur if some type of technique is not employed
9 to recover those reserves.

10 Q. Let me ask you as a geologist, Mr.
11 Jennings, whether or not you can, with confidence,
12 provide an accurate net pay porosity map for the
13 Mesaverde that then can be used by the engineers to
14 make volumetric calculations so that we could draw
15 some comparisons between what volumetrically is the
16 gas in place underlying a specific spacing unit and
17 compare that to what it may have cum'd or produced
18 over time? Now can you, as a geologist, give the
19 engineer a map that you think is reliable from which,
20 then, he can make those types of calculations?

21 A. No. It's partly attributable to the great
22 lateral variations in matrix porosity, but to a larger
23 extent it's because of the fracture component of the
24 reservoir. It's just simply unpredictable and does not
25 fit in the volumetric calculations.

1 Q. So if an engineer is going to work with
2 some cumulative production numbers, you're telling me
3 as a geologist you have no way to assist him in this
4 reservoir in telling him where that gas came from?

5 A. Correct.

6 Q. If he has some P/Z calculations where he's
7 given you what he projects this individual wellbore is
8 ultimately going to cum, you're unable to assist him
9 to accurately map where he gets that gas?

10 A. Yes. I would rather be in the thicker part
11 of the pay, but it's only a small part of the
12 reservoir picture.

13 Q. And you can see from looking at the various
14 cumulative producing volumes for this spacing unit and
15 all of the rest of the spacing units in the pool, that
16 there is quite a range of cumulative productions,
17 aren't there?

18 A. Definitely.

19 Q. Is there a direct geologic correlation,
20 then, to either cumulative production or
21 deliverabilities and the thickness in reservoir
22 volumes from which they produce that gas?

23 A. No.

24 Q. You have prepared, under your direction and
25 supervision, the other geologic interpretations that

1 are shown in the exhibit book?

2 A. Yes. And all those are are a larger
3 version of the net pay map and you can peruse those at
4 a later date if it will help you. Your copy of that
5 map is pretty small on the cross-section.

6 MR. KELLAHIN: Mr. Chairman, at this time
7 we move the introduction of Mr. Jennings exhibits on
8 pages 9 through 12 of the exhibit book, and that
9 concludes our direct examination.

10 CHAIRMAN LEMAY: Exhibits 9 through 12 will
11 be admitted into the record without objection. Mr.
12 Lund.

13 MR. LUND: Just a couple if I may, Mr.
14 Chairman.

15 EXAMINATION

16 BY MR. LUND:

17 Q. Mr. Jennings, your testimony about the
18 1950s wells versus the 1970s wells, what was your
19 conclusion, that the 1970s wells are more likely to be
20 better producers? Is that what you testified to?

21 A. My conclusion is that the old wells did not
22 drill to the bottom of the pay, didn't complete in the
23 top of the pay, and because of an efficient completion
24 technique, will not and now the mechanical condition
25 of the bore hole, because of the caved-in nature of

1 it, will not produce the reserves that are in that
2 160-acre unit.

3 Q. That's why so many of the original, parent
4 locations have been redrilled with better technology?

5 A. That's correct. That's why, when you
6 consider that over half of the wells in the basin are
7 the old wells, and think of every one of those 160's
8 as having additional reserves that will not be
9 drained, it's a very big picture.

10 Q. On your Exhibit No. 12, just a quick
11 question. You're showing an isopach net pay map for
12 the Riddle drilling unit. Isn't it true that the
13 original well to the south part of Section 4 has been
14 plugged and abandoned in the Riddle?

15 A. In the southeast quarter of Section 4?

16 Q. Yes, sir.

17 A. That's correct.

18 Q. Yet you're showing better pay there than
19 you do to the north of the section, don't you?

20 A. This map was constructed using roughly two
21 wells per section, which are the modern logs. The old
22 logs, which are basically induction logs, you can use
23 them to a minor degree, but you get a better degree of
24 accuracy if you use the modern logs and simply
25 interpolate between the data points. So the old wells

1 in the section, such as that one, were not used
2 because of the innacuracy of the old logs.

3 Q. Has Meridian considered doing a redrill of
4 the vertical well in the south?

5 A. Yes, we have considered it. It is one of
6 many old wellbores that was P & A'd because of
7 non-commercial daily production. And, yet, we don't
8 believe that that well has produced all the gas in
9 that 160-acre tract and is a good candidate for a
10 redrill.

11 Q. For a vertical redrill?

12 A. Frankly, if this type of technique would
13 work, certainly we don't plan on stopping after two
14 wells if it's successful.

15 MR. LUND: Thank you.

16 CHAIRMAN LEMAY: Additional questions of
17 the witness? Mr. Weiss?

18 EXAMINATION

19 BY MR. WEISS:

20 Q. You mentioned this is a fractured
21 reservoir. Is that the same as a naturally fractured
22 reservoir?

23 A. Yes.

24 Q. You also said there have been two other
25 deviated wells drilled?

1 A. Yes. And I--

2 Q. Where were they?

3 A. --I don't know all the details. I know
4 that the federal government conducted a research well,
5 I believe, in Pennsylvania, and I really don't know
6 that many details on it. Perhaps Louis, who will come
7 after me, might know something about the other well.
8 Very little information is available; basically a very
9 risky technique. However, we believe that because of
10 our experience in other areas, such as the horizontal
11 Bakken play in the Williston Basin, that we can do
12 it.

13 MR. WEISS: That's all I have. Thank you.

14 EXAMINATION

15 BY CHAIRMAN LEMAY:

16 Q. Mr. Jennings, I have a question that maybe
17 Mr. Jones might be more qualified to answer, so if he
18 is just defer to him, but you're laying an assumption
19 that you have sands in here that have not been
20 drained, as I understand?

21 A. Correct.

22 Q. And need to be contacted with the wellbore
23 on a diagonal well. Do you happen to know the initial
24 bottom-hole pressure of this field?

25 A. Roughly 1,500 pounds, I believe.

1 Q. Do you know the current bottom-hole
2 pressure?

3 A. Roughly 400 pounds.

4 Q. Would you expect, or are there examples of
5 wells when they've redrilled the 320, they've
6 encountered virgin pressures?

7 A. Not to my knowledge. That gets back to
8 your earlier question. If you could isolate the zone,
9 perhaps you could measure some higher reservoir
10 pressures. What you're looking at is a 1,200-foot
11 section of rock with one, perhaps, small area that
12 does have less-drained and less-depleted reservoir
13 and, therefore, will give you a higher reservoir
14 pressure. Really, I am getting out of my area of
15 expertise but, no, I do not know of any wells that
16 have been redrilled and encountered completely virgin
17 pressure.

18 CHAIRMAN LEMAY: I might pick that up with
19 the next witness. Thank you very much. I have no
20 further questions.

21 Call your next witness.

22 MR. KELLAHIN: Mr. Chairman, at this time I
23 would like to call Mr. Louis Jones.

24

25

1 LOUIS JONES

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

4 EXAMINATION

5 BY MR. KELLAHIN:

6 Q. Mr. Jones, for the record, would you please
7 state your name and occupation.

8 A. I'm Louis Jones, regional production
9 manager for Meridian Oil, Inc., in Farmington, New
10 Mexico.

11 Q. Mr. Jones, did you testify as production
12 manager of your company before Examiner Catanach when
13 he earlier heard this case?

14 A. Yes, I did.

15 Q. On prior occasions have you testified as an
16 expert in New Mexico prorationing matters before this
17 Commission?

18 A. Yes, I have.

19 MR. KELLAHIN: We tender Mr. Jones as an
20 expert production manager with particular expertise in
21 New Mexico proration.

22 CHAIRMAN LEMAY: His qualifications are
23 accepted.

24 Q. Mr. Jones, you've had an opportunity to
25 participate in this case and you have seen and

1 reviewed the Examiner Order entered by Mr. Catanach.
2 In your opinion, Mr. Jones, can Meridian go ahead and
3 institute this pilot project in either one of these
4 areas in the absence of modifying that order?

5 A. No, sir, we cannot. We do not feel like it
6 is certainly economically justifiable with the current
7 ruling as such. We're obviously concerned about our
8 ability to flow this well after we've spent a
9 tremendous amount of capital and taken the mechanical
10 risk. When we feel we have an alternative, with the
11 two times the "D", along with the cap. We think
12 that's very important. That's a major change from our
13 last hearing.

14 Q. Examiner Catanach was not afforded the
15 opportunity to decide the case based upon our
16 presentation of a cap or an upper limitation?

17 A. That is correct.

18 Q. As an engineer with expertise in
19 prorationing matters in New Mexico, Mr. Jones, would
20 you simply give us an example of how the system
21 currently works and what is the problem in allowing
22 the highly-deviated well to operate only with taking a
23 single times the deliverability of that well and
24 integrating that into the allowable for that well?

25 A. Right. I have an example on page 13, but

1 what I would like to do is kind of summarize again how
2 the allowables are determined. Using this proration
3 unit, which is 320 acres, you obviously get to take
4 each one of the deliverabilities, or the two, in this
5 case, and add them together to get a combined "D" for
6 that proration unit. Then your allowable for that
7 proration unit is determined by the D's. It's a
8 function of those D's that are generated from the two
9 wells.

10 So you get to add two vertical wells to
11 give you the addition for the total "D" for that
12 proration. Now, what we're asking for is because
13 we'll have one well within that 320, we're asking for
14 two times the "D" of that one well. It's essentially,
15 to me, not much different than exists today because we
16 have the opportunity to have two D's within the same
17 proration unit or the 160-acre spacing as was
18 mentioned earlier.

19 What I've done, I put an example in the
20 book to give you an idea of how a well could be
21 affected. It was asked earlier what we may expect out
22 of the well. I went ahead and I assumed 2.7 million a
23 day. Do we expect that? We certainly hope for it.
24 We're not exactly sure what to expect because,
25 obviously, this is a pilot project.

1 What I've assumed here is that our "D" is
2 equal to "Q," which is the rate of the well. That's
3 the well test data of 2.7 million a day or 2,000 Mcf
4 per day. If we take the total allocations for the
5 Mesaverde pool for 1990, and I just assumed that they
6 would equal 163 Bcf for the entire pool, then they
7 would be 12-percent higher than our 1989 numbers.

8 I've done that, Mr. Chairman, to try and
9 show what I think is a best guess. I think our
10 allocations will go up in 1990 for the pool. I've
11 tried to be as realistic as possible on this example.
12 I've also assumed that the well would decline at five
13 percent per year. I think that's a reasonable
14 assumption for the Blanco-Mesaverde and the San Juan
15 Basin. And then I've showed that what exists today
16 with the ruling of one times the "D" for the entire
17 proration unit.

18 If that occurred, all these assumptions
19 hold true, and I feel they are our best guess. And we
20 could produce this highly-deviated well for 7.5
21 months, straight, at which time it would be 12 times
22 overproduced. After that, you could keep the well
23 under the current rules and regulations at 11.9 times
24 overproduced by producing it only four and a half
25 months out of the year. It just gives you an example

1 of what the proration in the Blanco-Mesaverde in the
2 San Juan Basin can do, as far as your applicable
3 production.

4 Q. If that type of allowable restriction is
5 left in place, then is Meridian going to be able to
6 justify the economics of spending the money in order
7 to develop these as pilot projects?

8 A. No, sir, we would not. Without some type
9 of assurance of continuing to flow these wells and
10 recover our capital expenditures and, of course, the
11 mechanical risks that we take, we would be much better
12 off going and drilling a vertical wellbore.

13 Q. Based upon your knowledge and experience
14 and your expertise in this particular area, do you
15 conclude that Meridian will enjoy an unfair advantage
16 over Amoco or anyone else that does not have in
17 offsetting spacing units a highly-deviated well?

18 A. I do not believe so, for a couple of
19 reasons. First of all, they have the opportunity to
20 do the exact same thing. The technology is out
21 there. But secondly, we've added a cap, and that cap
22 is what exists today and has existed for 35 years.
23 I'm saying it's no more of an unfair advantage than
24 has existed the last 35 years. I think that cap
25 certainly will give Amoco, I hope, and other offset

1 operators, at least some comfort on their protection
2 of correlative rights.

3 Q. Describe how the mechanics of the cap would
4 work.

5 A. This was brought up earlier. Meridian
6 would be willing to move that cap, with time, to just
7 match the highest proration unit in the San Juan
8 Basin, Blanco-Mesaverde pool, of vertically drilled
9 wells as it exists today, because we could go out
10 today and drill two vertical wells and maybe even
11 exceed the highest that exists today with Amoco. But
12 we are willing to float that.

13 If the 16 million a day proration unit
14 drops to whatever, 10 million, 8 million, then we want
15 to go back to the highest proration unit existing by
16 any operator, not just Amoco, obviously, but by any
17 operator in the Basin, and maybe Meridian.

18 Q. Do the mechanics of prorationing in the
19 Mesaverde pool allow the deliverability of a spacing
20 unit to be set by the corresponding deliverabilities
21 of the offsetting spacing units?

22 A. What the request is, is that we take two
23 times the deliverability of the highly-deviated well.
24 Let's use this example. For example, "D" is equal to
25 our rate of 2.7 million a day. What we're requesting

1 is that we utilize two times the "D" of that well.
2 So, in this case, it would be 5.4 million a day as a
3 "D", and that would be the "D" for that proration
4 unit, not the 16 million a day. We're just using the
5 16 million a day to give comfort. That could be the
6 peak. Obviously we would like to make as good or
7 better well than what I've shown here. We would like
8 to have some of that upside. But we are also limiting
9 our upside with that cap that exists out there today.

10 Q. Why shouldn't that cap be reduced to a
11 point where it doesn't exceed the offsetting combined
12 deliverabilities of the Amoco spacing unit, for
13 example?

14 A. Under the current rules and regulations,
15 that's the way it exists today and has existed for 35
16 years.

17 Q. That's simply because we use deliverability
18 as one of the components by which we set the producing
19 rates for the pool?

20 A. That's correct.

21 Q. There already exists, does there not in the
22 Basin for this pool, Mr. Jones, wide ranges of
23 disparities in deliverabilities that are used between
24 and among wells?

25 A. Wide ranges of deliverabilities and wide

1 ranges of cumulative production. And it's a function
2 of the permeability and the amount of pay that is
3 intersected with the wellbores.

4 Q. Would you, as an engineer with experience
5 in this area, Mr. Jones, be willing to have Amoco do
6 what you propose to do in this case?

7 A. Absolutely.

8 Q. Without reservation?

9 A. Yes, sir.

10 MR. KELLAHIN: No further questions, Mr.
11 Chairman.

12 CHAIRMAN LEMAY: Thank you Mr. Kellahin.
13 Mr. Lund.

14 EXAMINATION

15 BY MR. LUND:

16 Q. Mr. Jones, as I understand your testimony,
17 the only difference from the hearing before the
18 Examiner was your proposal that you've raised today to
19 put a production cap?

20 A. That is correct.

21 Q. And is it still your feeling that you need
22 some sort of guaranteed economics to make this
23 drilling project viable for your company?

24 A. That is correct.

25 Q. You're participating in a study committee,

1 aren't you, for New Mexico, that's looking at the
2 prorated pools and potential solutions to some of the
3 problems that have arisen?

4 A. Yes, I am.

5 Q. Isn't it fair to say the real problem we're
6 talking about here is the allocation system that
7 allows deliverability to be calculated?

8 A. Well, obviously it's part of the proration
9 system. We are certainly concerned about the ability
10 to flow the well after the capital is spent.

11 Q. Well, look at your Exhibit 13.

12 A. Okay.

13 Q. You're setting forth there the problem with
14 the way the allocation system works now and how you
15 run into the 12 times overproduced rules therefore
16 requiring a well to be shut in?

17 A. Yes, sir.

18 Q. And everybody is facing that problem,
19 aren't they?

20 A. Yes, sir.

21 Q. All the offsets to the units you've been
22 describing are facing that problem?

23 A. Yes, sir.

24 Q. But yet you want some special rules for
25 your two units as opposed to what the offsets are

1 getting, don't you?

2 A. We are asking for a special allowable to
3 justify the risk.

4 Q. All the offsets are living with those
5 prorated pool rules and yet you want a two times
6 deliverability factor for your two proration units?

7 A. It's two times the deliverability of one
8 well.

9 Q. Of the deviated well?

10 A. That is correct.

11 Q. You think that's fair?

12 A. Yes, sir.

13 Q. Why?

14 A. As I stated before, it's essentially
15 160-acre spacing now and we're covering 320-acre
16 spacing. With this two times ruling, if accepted, it
17 would give us the comfort to go ahead and spend the
18 additional dollars necessary to test this pilot
19 project.

20 Q. No other operator in the pool gets two
21 times the deliverability factor for one, do they?

22 A. Not for one well, but they get two wells
23 within the proration unit.

24 Q. Now, you stated earlier that there's no
25 violation of correlative rights because all the

1 operators have the opportunity to do the same thing
2 you're proposing, is that right?

3 A. The technology exists, we believe.

4 Q. Yet you and your witnesses have spent a lot
5 of time talking about how risky this is, how expensive
6 it is, and how many problems could result?

7 A. Yes.

8 Q. You think it's fair for us to take the same
9 risks in an unproven technology?

10 A. Oh, I think what we're asking for is
11 certainly some guaranteed economic justification for
12 testing.

13 Q. I sure understand that's what your position
14 is. You also testified that with the cap that you
15 propose, that's the same thing that's been happening
16 for 35 years?

17 A. I'm saying there's no more risk to the
18 offset operators than exists today in the
19 Blanco-Mesaverde pool. You have that same risk today
20 if I go out and drill a vertical well. In fact, it
21 could be 20 million a day "D." The reason we through
22 in the cap, obviously we were trying to give comfort
23 to the offset operators, that we'll take the cap for
24 the current proration units that exists today that
25 have been vertically drilled. We're looking for a way

1 to make this more palatable. Obviously the concerns
2 are the correlative rights.

3 Q. Sure, and that's why we're here, you know.
4 We think it's a great idea. I don't think that's
5 really fair, and let me ask you this. You say it's
6 the same thing that has been in existence for 35
7 years, but nobody gets a two times "D" factor for any
8 one well?

9 A. When I say it's the same thing that's been
10 in existence, I'm saying that offset capacity for that
11 proration unit to produce at that level to get that
12 allowable has existed, and it still exists today.

13 Q. That's the other factor you're cherry
14 picking in your proposal, because you're proposing
15 that you look at the highest deliverability from any
16 proration unit in the entire Blanco-Mesaverde pool and
17 match that highest for your two deviated wellbores?

18 MR. KELLAHIN: Objection to the
19 characterization of this as "cherry picking." I think
20 that's argumentative, Mr. Chairman.

21 CHAIRMAN LEMAY: It is. All's you have to
22 do is start out with "are you," and then your
23 statement, rather than being argumentative by saying
24 "you are." Just reverse the pronouns there.

25 MR. LUND: I did not mean to be

1 argumentative.

2 A. We are willing to place a cap equal to the
3 highest proration unit that exists today.

4 Q. The difference is, what you're looking at
5 now is, you're looking at your direct offsets for
6 terms of correlative rights consideration, isn't that
7 true?

8 A. Could you restate that?

9 Q. Sure. Right now, when you're concerned
10 about correlative rights, you look at your offsets and
11 see what they're producing, correct?

12 A. Yes, sir.

13 Q. Then you can take appropriate action
14 depending on what your offsets are producing?

15 A. Yes, sir.

16 Q. Under your scenario, that's not going to be
17 the case anymore, because instead of looking at your
18 direct offsets you have to be concerned about the
19 highest deliverability proration unit in the field?

20 A. Yes, sir, that's what we're asking for.
21 Now, realizing that I think it's a very, very small
22 probability that we'll ever meet that cap. We hope
23 to, but I think it's a small probability that we would
24 meet it. We certainly want it there for our economic
25 justification to go drill these wells.

1 Q. The final question. You're going to move
2 your deliverability up and down depending upon what
3 the highest proration unit does?

4 A. No, sir. We take two times the
5 deliverability of that well. Let's say the well
6 tested at 2.7 million a day. The deliverability for
7 that proration unit would be 5.4 million a day,
8 assuming that 5.4 million a day is no larger than any
9 existing proration unit in the Basin today.

10 Q. So if the highest deliverability of any
11 proration unit in the basin was 2, you would not
12 exceed that for your deviated well?

13 A. The cap would be 2, yes, sir.

14 Q. It would move up and down?

15 A. Yes, sir, as long as the 2 times the "D"
16 was affected by the cap.

17 MR. LUND: I was confused about that based
18 on your testimony. Thank you very much.

19 CHAIRMAN LEMAY: Any additional questions
20 of the witness? Mr. Weiss.

21 EXAMINATION

22 BY MR. WEISS:

23 Q. Is a hearing required if you want to do a
24 massive frac job, I mean, pump a couple million pounds
25 of sand in a well?

1 A. No, sir.

2 Q. How is the "D" calculated on a well out
3 there if you do a massive frac?

4 A. It's calculated the same way as the
5 existing formula. I don't have the formula with me,
6 but it's a function of rate and pressure draw down.
7 In most cases throughout the Basin, the "D" equals the
8 "Q." That's a pretty good assumption.

9 Q. I didn't phrase my question properly.
10 Let's say you drill a third well, one of them is bad,
11 is damaged, you can't use it anymore, on 160 acres,
12 you drill a third well, and you spend a million
13 dollars fracking.

14 A. Yes, sir.

15 Q. What is that "D" based on? Which well?
16 That well? two wells? three wells?

17 A. No, it's that well. But you get that well
18 plus the other well on a proration unit added on top
19 of it.

20 Q. Do you think--

21 A. So you still get two wells out of the 320.

22 Q. You mentioned the "D" was dependent on the
23 quality of the sand and the porosity. Do you think
24 it's dependent upon the amount of money you spend on
25 the completion?

1 A. No, sir, it really depends on the type of
2 rock that you intersect, in most cases.

3 Q. If the "D" were based on the best two out
4 of three wells on a 320 acres, would Meridian drill a
5 horizontal well or deviated well?

6 A. We feel like the two times is justification
7 for us to drill. That's what we're asking for.

8 Q. I didn't hear the answer to my question.

9 A. I cannot answer that at this time. I think
10 that the two times the "D" is a justification that we
11 would need to drill the wells.

12 Q. I had a question on the cap also. Let's
13 say this deviated well comes in at 25 million a day
14 and today the maximum "D" is 16 million a day.

15 A. Yes, sir, for proration.

16 Q. Next month, what would the cap be?

17 A. The proration units, their deliverability
18 changes every two years unless they are retested for
19 some reason, such as workover, reperforating, et
20 cetera. The "D" of 16 million a day was predicated on
21 the 1986 program that took effect in 1987. We have
22 some new tests that will take effect April 1, 1990. I
23 do not know what that maximum is at this time.

24 Q. It's conceivable, then, that that cap could
25 change to what you've deviated?

1 A. I fully expect that cap to change, and I
2 fully expect that cap to go down.

3 Q. Would you expect it to change to the 20
4 million a day out of the deviated well?

5 A. No, sir. My best guess of what I think the
6 cap would change to, let's say April 1, would be in
7 the 12 million a day range. That's what I'm expecting
8 out of the vertical wells in the current proration
9 units. Obviously, if you drilled a 25 million a day
10 highly-deviated well, we would be limited to the 12
11 million a day.

12 Q. For the two years or for a test period, and
13 then it would go to 25?

14 A. No, sir, we're saying we would always float
15 with that.

16 Q. Wells other than the deviated wells?

17 A. Right, the vertical wells.

18 Q. If you would look at Exhibit 3 there, on
19 Section 22?

20 A. Okay.

21 Q. I see that the deliverability on the west
22 half of that section is about six times that of the
23 east half. How are correlative rights handled there?

24 A. There are wide variances in deliverability
25 and cum's throughout the Basin, and the proration

1 system has been in place for many years in an attempt
2 to protect correlative rights, in an attempt to afford
3 everyone the opportunity to protect their correlative
4 rights.

5 Obviously, in this case, the offset
6 operator has a current advantage if he wants to
7 produce his gas. He can produce more gas under the
8 allowable system than we can in the east side of the
9 proration unit at this time. That's a current
10 advantage. Now, I'm not looking at the history.
11 Obviously that was brought up earlier.

12 MR. WEISS: That's all the questions I
13 have. Thank you.

14 CHAIRMAN LEMAY: Thank you, Mr. Weiss.

15 EXAMINATION

16 BY CHAIRMAN LEMAY:

17 Q. Did I hear you, Mr. Jones, say that you
18 thought reserves were based on the amount of pay or
19 that was a factor encountered in the wellbore, the
20 amount of productive sand encountered in the wellbore,
21 was one function of the reserves under prorationing?

22 A. It was a function, yes, sir.

23 Q. As I understand a previous witness, I
24 thought he'd made the comment that it has nothing to
25 do with the amount of reserves recovered under a

1 proration unit?

2 A. It's not the only thing that affects the
3 production in the cumulative recovery from that
4 proration unit. Obviously variations in permeability,
5 fracturing, play a major part in the total recovery
6 from that proration unit.

7 Q. Following up, you have been certainly
8 involved in this field for some time, both with
9 Tenneco and with Meridian. Under the in-fill well
10 drilling program, have you encountered any wells that
11 have had some virgin pressure on the in-fill program?

12 A. Most of our in-fill wells have been in the
13 middle of the Basin where they've been produced, where
14 the Mesaverde has been produced for many, many years
15 in the better quality areas, because these are
16 redrills of old open holes. The old open-hole
17 technique was utilized in the middle 50's and they
18 drilled up the best part of the reservoir first.

19 So I feel like we are intersecting lenses
20 that may have virgin pressure. Whenever you perforate
21 the entire interval you do not see that, because then
22 you're in communication with the rest of the intervals
23 in your wellbore. We don't have the documentation
24 that we have virgin pressure in any one piece. I feel
25 like that's a good possibility. It becomes much more

1 of a possibility as you move to the edges of the Basin
2 where the Mesaverde gets tighter. I believe this
3 technique has a tremendous potential, particularly on
4 the edge of the basin, where the vertical Mesaverdes
5 now are not profitable.

6 Q. The assumption I'm trying to get at is that
7 you have these sand lenses that have not been
8 intersected by a wellbore.

9 A. Yes, sir.

10 Q. Or an alternative, I guess, can't find a
11 way to drain to fractures that set at or to a
12 wellbore.

13 A. Yes, sir.

14 Q. I would expect, unless you're taking gas
15 out of one zone and putting it in another zone acting
16 as a free zone, that when you drill an in-fill well,
17 occasionally you would intersect some of these sands
18 and they would have close to virgin pressure and you
19 would be able to see that, if those sand lenses had
20 not been drained in the past?

21 A. We don't have the measured data for virgin
22 pressure. We have seen higher pressure intervals. I
23 think we showed that earlier on the P/Z.

24 Q. In a production sense, yes. Do you test
25 the pressure of a well when you drill an in-fill well?

1 A. Yes, sir.

2 Q. What are those wells coming in at,
3 generally?

4 A. In the center of the Blanco-Mesaverde
5 reservoir it may vary anywhere from 4- to 700 pounds
6 bottom-hole pressure. As you move out into the edges
7 the pressure increases, because it's a much tighter
8 reservoir.

9 Q. Do you think that the vertical wells that
10 are currently within your proration units would
11 ultimately drain the gas in place in that proration
12 unit? It may take 50 years to do so, but would
13 ultimately get that gas?

14 A. I do not. I feel like we need to intersect
15 additional sand lenses that exist in the proration
16 units today.

17 Q. You don't feel that a diagonal well would
18 do more to increase your deliverability and not your
19 reserves? You feel it would also increase the
20 recoverable reserves?

21 A. We're hoping to under that proration unit,
22 yes, sir.

23 CHAIRMAN LEMAY: I have no further
24 questions. Thank you. Additional questions? The
25 witness may be excused.

1 MR. KELLAHIN: Mr. Chairman, I have an
2 additional witness to call at this time. He has not
3 been previously sworn. I would like to call the
4 president and chief executive officer of Meridian Oil,
5 Inc., Mr. Don Clayton.

6 CHAIRMAN LEMAY: We're very happy to have
7 Mr. Clayton in Santa Fe.

8 DONALD W. CLAYTON

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

11 EXAMINATION

12 BY MR. KELLAHIN:

13 Q. Mr. Clayton, for the record, sir, would you
14 please state your name and occupation?

15 A. Donald W. Clayton. I'm CEO and president
16 of Meridian Oil.

17 Q. Mr. Clayton, will you give us some of your
18 professional background and employment history in a
19 summary fashion?

20 A. I have a B.S. degree in petroleum
21 engineering; I'm a registered professional engineer.
22 I have drilled all over the world and produced all
23 over the world, and I consider expertise not only in
24 drilling and producing, but engineering, geology and
25 geophysics and petrophysical analysis.

1 Q. How long have you been the chief executive
2 officer of your company?

3 A. For a little over two years.

4 Q. During the course of your employment in
5 that capacity, have you been involved with production
6 on behalf of your company in San Juan Basin, New
7 Mexico.

8 A. Yes, I have.

9 Q. Why have you taken the opportunity to come
10 and appear before this Commission today, Mr. Clayton?

11 A. Mr. Chairman, Commissioners, I think that
12 the outcome of this hearing is important to Meridian
13 Oil. I think it's important to the oil and gas
14 industry in the State of New Mexico, and I think it's
15 important to the State of New Mexico.

16 In 1986, the State of New Mexico's annual
17 gas production had gone down to 692 Bcf or about 1.89
18 Bcf per day. In 1989, the production was back up to
19 830 Bcf, or approximately 2.3 Bcf per day. The result
20 of that dramatic turn-around in produced gas volumes
21 in the State of New Mexico is the result of new
22 technology brought to the San Juan Basin in the State
23 of New Mexico.

24 I'm here today on behalf of Meridian Oil to
25 bring additional new technology to the San Juan Basin

1 and to the State of New Mexico. Let me state that
2 Meridian's objective is the same objective that the
3 State of New Mexico has, and that's to efficiently
4 manage the development and production of
5 hydrocarbons.

6 Specifically in the Mesaverde gas
7 reservoir, there has been 7.8 trillion cubic feet of
8 gas produced. What we are here today to ask this
9 Commission to consider is giving us a favorable
10 variance to the proration rules based on economic
11 justification that's been presented on two wells.
12 There have been over 19,000 completions in the San
13 Juan Basin. We ask for the luxury of an exception to
14 the rules on two wells out of 19,000 that have
15 historically been completed. I think that is fair and
16 reasonable.

17 Let me tell you the larger perspective that
18 I see in either proving or disproving this
19 technology. It's my personal opinion and testimony,
20 as a professional registered engineer, CEO and
21 president of Meridian Oil, that this technology of
22 highly-deviated gas wells and/or lateral drilling
23 technology, will increase the ultimate recovery in the
24 Mesaverde gas formation up to 15 percent, or
25 approximately two trillion cubic feet of additional

1 gas reserves will be recovered out of the Mesaverde if
2 this technology is successful.

3 We've heard a lot of testimony here today.
4 I'm going to break it down into two simple things.
5 The highly-deviated gas well in the Mesaverde
6 formation will allow you an increased sweep efficiency
7 of about 10 percent. And that can be demonstrated
8 with follow-up documents, should you like to have it.

9 In addition to that, the San Juan Basin is
10 7,500 square miles. Geology and subsurface
11 engineering, geophysics and petrophysics is not an
12 exact science. When mother nature laid down those
13 formations, she had some areas that had high
14 permeability, some that had low permeability, some
15 that had no permeability, and some that had micro
16 fractures and larger fractures. The second part, in
17 addition to the sweep efficiency, is that drilling the
18 highly-deviated gas well in the Mesaverde will let you
19 intersect micro fractures and other fracture systems
20 that have not been penetrated by the traditional
21 vertical well and have not been fractured into by the
22 wellbore stimulation techniques as we know in 1990.

23 Those two reasons are the reasons that I
24 believe that this new technology has that topside
25 potential. Let me go one step further and tell you,

1 when this technology is developed and applied, it will
2 not be limited to the Mesaverde formation. It will
3 also be applied to Picture Cliff in the Dakota
4 Formation. Again, I think as a registered
5 professional engineer, in my opinion you could expect
6 an increased sweep efficiency and penetrating
7 fractures not penetrated by vertical wells where you
8 will increase your ultimate recovery from those
9 traditional formations up to 15 percent. Or a total
10 now, from all traditional zones in the San Juan Basin,
11 of about five trillion cubic feet of reserves that
12 would not be recovered under current state of the art
13 expertise.

14 Let me break that down into a dollar
15 figure. The Mesaverde alone, with approximately two
16 additional trillion cubic feet, if recovered, would
17 generate incremental income to the State of New Mexico
18 of approximately \$300 million. If the technology were
19 successful and applied to all formations and you got
20 up to the five trillion cubic feet of ultimate
21 recovery, then you would be looking at incremental
22 revenue to the State of New Mexico in excess of
23 one-half a billion dollars, and that's why I'm here
24 today.

25 Let me go ahead and share with you what's

1 going on in the State of North Dakota, the Williston
2 Basin. They're currently relaxing the procedures to
3 allow you to get permitted with high-angle wells or
4 lateral technology wells, and they're also rewriting
5 the guidelines for these type wells.

6 In addition to that, the State of North
7 Dakota has reduced the severance tax on these specific
8 wells with this technology, from 12 percent to 5
9 percent. They did that fully realizing that that
10 would probably be a loss of income to the state.
11 What's happened is, the State of North Dakota didn't
12 lose revenue, their severance tax went up one billion
13 dollars for Meridian alone.

14 If you move into your sister State of
15 Texas, you'll see that one high-angle well or
16 laterally drilled well is given an oil allowable of
17 four times a vertical well. Those rules are currently
18 being relaxed and in this morning's paper they have an
19 article stating that they plan to rewrite the rules
20 governing high-angle wells or lateral wells in the
21 State of Texas.

22 Let me go ahead and talk about this
23 technology. High-angle gas wells and/or lateral
24 drilled wells, it's my personal opinion that when
25 Meridian develops and applies this technology, that

1 all producers in the State of New Mexico will benefit
2 from the work that Meridian and others, such as Amoco,
3 ARCO, Conoco, or any who elect to develop this
4 technology, that they will share in the benefits of
5 this technology very similar to the way that they're
6 now currently sharing in the coal seam degasification
7 project that was brought to the San Juan Basin. That
8 technology is not limited to Amoco and it's not
9 limited to Meridian, and I think you've seen a
10 dramatic turn-around in gas volumes.

11 I'm here today to tell you that, in my
12 perspective, I feel very positive about the technology
13 discussed today, what it can do for Meridian, what it
14 can do for the oil and gas industry in the State of
15 New Mexico, and what it can do for all the people of
16 the State of New Mexico in incremental revenue that
17 would be left behind if these wells were not allowed
18 to be drilled. Thank you very much for taking the
19 time to hear me.

20 Q. Mr. Clayton, let me ask you a follow-up
21 question to your comments. Will you authorize the
22 drilling of the two pilot project wells for the State
23 of New Mexico under the current Examiner Order?

24 A. We have an investment, a high-risk
25 investment in the State of New Mexico in the hundreds

1 of millions of dollars on coal seam degasification,
2 where we took all that risk up front. I feel very
3 good about this type of technology, but Meridian, as
4 the ninth largest gas producer based on domestic
5 reserves, has other projects in the United States.
6 What we do is simply apply the prioritization by
7 discounted profit to discounted investment, and pick
8 the wells that we drill because we have an obligation
9 to the shareholder.

10 Meridian currently, right now, only has
11 about a four-and-a-half-percent return on net assets.
12 From all the hundreds of millions of dollars we've
13 invested throughout the United States, a
14 four-and-a-half-percent return is not adequate to the
15 shareholders, so we have an obligation to invest our
16 money from this point in time forward in the wells
17 that are economically attractive.

18 In answer to your question, the wells,
19 without the two times that some of our people have
20 talked about in the equation, will simply compete on a
21 discounted profit to discounted investment
22 prioritization, and in all likelihood they will not
23 get drilled.

24 MR. KELLAHIN: Thank you, Mr. Chairman.

25 CHAIRMAN LEMAY: Mr. Kellahin, Mr. Lund.

EXAMINATION

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BY MR. LUND:

Q. Mr. Clayton, I think you testified that you want a favorable variance to the proration rules for two wells out of 19,000?

A. I testified to the favorable exception to the current rules on two wells. I doubt very seriously if two wells is a significant threat to any of the producers in a Basin 7,500 square miles, as far as taking an unfair drainage situation. And after the two wells, we'll look at the results jointly and decide with this Commission and with the industry where we go at that time.

Q. You're familiar, aren't you, Mr. Clayton, with the duty of a lessee to protect their lease against drainage, aren't you?

A. Yes, I am.

Q. And that applies to each lease on an individual basis, not on a big picture basis, doesn't it?

A. I think that Meridian has an obligation to its royalty holders. If we're going to leave, as an industry, two trillion cubic feet behind in the Mesaverde because we need to make some rule changes, then I don't think as CEO and president of Meridian,

1 I'm doing my job.

2 I think until that expertise is developed
3 and used and widely accepted by all the industry,
4 there will be some discrepancies. But I think the
5 biggest discrepancy would be to take a landowner's
6 land and not do the things as a prudent operator you
7 need to do, and leave two trillion cubic feet behind
8 in the Mesaverde and leave three additional trillion
9 cubic feet behind in the Picture Cliff in Dakota, when
10 this Basin is going to be running short of energy in
11 the year 2000 and beyond. That's where the bigger
12 obligation lies, and that's where the bigger picture
13 scenario comes in.

14 Q. I don't think we dispute your bigger
15 picture, sir. My question was, isn't it true that as
16 a legal obligation we have to protect each lease
17 against drainage, not just looking at the big
18 picture?

19 MR. KELLAHIN: Object to the question.
20 He's framed it in context of a legal obligation, and
21 this witness is not qualified as a lawyer to render a
22 legal opinion.

23 MR. LUND: That's a good point. I withdraw
24 the question. I didn't mean to state it that way.

25 Q. Based on your understanding of the oil and

1 gas business, and you've got considerable experience,
2 isn't it fair to say that each lease must be
3 protected from drainage?

4 A. When Meridian takes a leasehold, as a
5 prudent operator we do everything that we can to go
6 ahead and see to it that our leaseholder and Meridian
7 is protected from drainage. But that is no excuse to
8 be inefficient and go through, like some of the
9 industry did the last 30 years, and not be as
10 efficient with the State's natural resources or the
11 royalty holder's resources and not develop that
12 property in a prudent and efficient manner.

13 Q. I think you stated that if this technology
14 works, you expect an increase of 15 percent in
15 ultimate recovery from this pool?

16 A. The statement was, up to 15 percent. That
17 would approximately be 10 percent due to the increased
18 sweep efficiency, which I'll be very pleased to draw
19 up on a chalkboard, if you would like to see it, and
20 then up to 5 percent increase from micro fractures and
21 larger fractures not penetrated by traditionally
22 vertically drilled wells and/or well stimulation, such
23 as fracturing, that go in an uncontrolled direction,
24 that may be adverse to what the fractures are.

25 Q. I take it you've done a study that leads

1 you to those two conclusions?

2 A. That's not necessarily a study. I've
3 witnessed that. I've witnessed it in drilling 33
4 lateral wells in the Williston Basin in North Dakota
5 and some 47 high-angle or lateral wells across the
6 United States.

7 Q. That's in some sort of report or some sort
8 of--

9 A. It's in the same form as it is at Amoco.
10 It's in the form of proprietary information.

11 Q. But you're not suggesting you want to
12 disclose that to the Commission?

13 A. I would be glad to show the general
14 principle, if you would like to see it.

15 Q. Yes, sir, I would.

16 A. May I have a chalkboard?

17 A. If the Commission would excuse a non-draft
18 person, if this were 160 and 160, and you drilled two
19 vertical wells, the experts have testified to a radius
20 of drainage in the two vertical wells as such. Now,
21 if you can picture drilling down and horizontal
22 through these points, and let's say this is where your
23 well went down vertical, and you drilled horizontal
24 and, you have this same radius of drainage that
25 earlier experts have testified, then your drainage

1 area is going to come across as a rectangle. And the
2 shaded area here, geometrically, is an area of the
3 reservoir that will not be swept and have the sweep
4 efficiency of the radius drained by two vertical
5 wells. When you calculate that out, you come out with
6 approximately a plus 10 percent additional sweep
7 efficiency that would not get drained under uniform
8 homogeneous permeability of a reservoir.

9 I'm saying you'll get up to 10 percent for
10 increased sweep efficiency. And then, it's my
11 personal opinion, if you have a vertical well here and
12 you have a vertical well here and you have a pooling
13 or a fracturing in this area, in this area, in this
14 area, in this area and some of them running through
15 the well, and these fractures are not hooked up, when
16 you drill down and vertical you'll intersect all
17 fractures. In fact, it's almost theoretically
18 impossible to miss them, because mother nature did not
19 lay them down parallel to each other, and it's highly
20 unlikely that you have the technology to drill a
21 straight, parallel well with fractures, so you're
22 going to pick up the gas in the porosity of the micro
23 fractures and fractures larger than micro fractures,
24 and that's where you'll get up to an additional 5
25 percent. Any questions?

1 Q. I take it you agree with Mr. Dunn, I think
2 his analogy was a vertical stack of pennies, and if
3 you lay it down it will get that increased area?

4 A. I agree with what I just explained.

5 Q. You don't agree with Mr. Dunn's analogy?

6 A. I don't disagree with Mr. Dunn, but a stack
7 of pennies, I think, was an attempt to try to convey
8 something very technical to a legal mind, that would
9 understand what I just explained.

10 Q. We certainly need all the help we can get;
11 as Mr. LeMay always says, lawyers are incompetent.

12 Is it your opinion that the drainage from
13 that deviated wellbore would not cross over into the
14 offsetting 160's?

15 A. On a individual case-by-case, I have no way
16 of knowing whether it it will or it won't, and nobody
17 else does either.

18 Q. You have to look at what the production is
19 before you can make that determination?

20 A. You can't even make that determination
21 after you get a P/Z. Can you look down below the
22 ground in excess of one mile and tell me how far and
23 in what directions mother nature put the main fracture
24 system, let alone the offset azimuth of the micro
25 fractures coming off the main fracture system? It's

1 highly unlikely.

2 Q. All I'm asking you is, can you determine
3 what the drainage radius is going to be of a deviated
4 wellbore in the absence of production data?

5 A. There are engineering calculations. It's
6 not an exact science.

7 Q. Would the drainage radius be larger if the
8 well is extremely productive and it does intersect
9 these micro fractures that you've been discussing?

10 A. I'll refer back to earlier expert
11 testimony. It's not predicated on any one parameter
12 but many variables, such as porosity, permeability.
13 Is it a uniform sandstone with no fractures? does the
14 sandstone have micro fractures? micro fractures and
15 larger fractures? The question is too general.

16 Q. You're not testifying that the deviated
17 wellbore would never drain beyond the 160, are you, or
18 the 320?

19 A. In what example?

20 Q. Well, you're laying out all these factors.

21 A. This is a hypothetical example. I'm sure
22 that you're aware, as an attorney, that you have well
23 spaces down to two acres in size and you have some
24 that are in excess of 2,000 acres. A lot depends on
25 where the drilling is and what the characteristics of

1 the reservoirs are. I can tell you, in 7,500 square
2 miles in the San Juan Basin that you're going to have
3 to look at that on an individual,
4 geographic-by-geographic area, to determine whether
5 160 is proper, 320 or 40 or whatever. You can't make
6 any general assumptions to cover the San Juan Basin in
7 the Mesaverde and Dakota. It's too big.

8 Q. So you can say, too, you can't make a
9 general assumption that this deviated wellbore would
10 not drain beyond a 320, either?

11 MR. KELLAHIN: Mr. Chairman, that question
12 has been asked and answered twice now, already. I
13 don't know how else the witness can answer it.

14 MR. LUND: I think I'm entitled to a
15 response to that, Mr. Chairman.

16 MR. KELLAHIN: He would be answer the same
17 question.

18 CHAIRMAN LEMAY: Just rephrase the question
19 and I'll make a ruling. What were you asking, Mr.
20 Lund?

21 Q. Mr. Clayton, all I'm asking--

22 MR. KELLAHIN: Excuse me.

23 MR. LUND: Excuse me. Let me ask the
24 question.

25 MR. KELLAHIN: You've already asked the

1 question. I've objected. And the basis for the
2 objection is that Mr. Clayton has said that none of
3 the engineers in this room can tell you if there's
4 going to be drainage or not in the Mesaverde, and now
5 he wants to ask him the same question again.

6 CHAIRMAN LEMAY: Is that your question?

7 MR. LUND: I think that mischaracterizes
8 the point.

9 CHAIRMAN LEMAY: I want to hear the
10 question again, if it's the same as Mr. Kellahin says
11 has been answered. If it's a different question, then
12 maybe the witness can respond.

13 Q. (BY MR. LUND) I think you testified, and
14 correct me if I'm wrong, sir, that you can't tell what
15 this drainage radius is going to be on this deviated
16 wellbore because you need a whole bunch of additional
17 information?

18 A. I think within the limits of the technical
19 expertise of the technical group that does reservoir
20 engineering, whether it be at Amoco, Meridian, Exxon
21 or anyplace else, that they can give a very scientific
22 best guess based on accepted formula in all the many
23 parameters that reservoirs have. Now, if you're
24 asking me about a specific well in the San Juan Basin,
25 whether it will or it won't drain more than this

1 radius, I'll defer that to the technical people we
2 have working that specific area.

3 Q. All I'm asking you, depending on those
4 variables that you mentioned, this deviated wellbore
5 could drain less or greater than a 320, isn't that
6 right?

7 A. Yes.

8 Q. Would Meridian still drill these two
9 deviated wellbores if it did not get the two times
10 deliverability factor?

11 A. I think I've answered that question. Those
12 two wells, without what we've asked for, will have to
13 compete on a discounted P over a discounted I basis
14 with the other projects we have across the United
15 States. I don't want to waste the Commission's time
16 or my time answering the same question more than once.

17 Q. So your answer is no?

18 A. My answer is what I said.

19 CHAIRMAN LEMAY: Mr. Lund, we don't want to
20 characterize the witness's answer. I think it was a
21 conditional response, as I heard it, not yes or no but
22 it would have to depend on upon these other
23 variables.

24 MR. LUND: Mr. Chairman, I don't mean to be
25 argumentative. I'm just trying to understand what the

1 witness testified to.

2 CHAIRMAN LEMAY: Yes, I understand that.

3 MR. LUND: Thank you.

4 CHAIRMAN LEMAY: Thank you. Additional
5 questions of the witness? Commission Weiss?

6 MR. WEISS: Yes.

7 EXAMINATION

8 BY MR. WEISS:

9 Q. What has been Meridian's experience and
10 yours, when you go to the Commissions in other states
11 and request this type of an allowable?

12 A. To be quite candid with you, the State of
13 North Dakota at one time ran in excess of 30 rigs and
14 they were down to two rigs running, both Meridian.
15 They came to us, when we elected to move back into
16 fractured fractured Bakken shale, and said, "What can
17 we, as the State of North Dakota, do to get you people
18 to bring your technology up to the wellbore in North
19 Dakota, get it out of the research labs and drill a
20 well?"

21 And we asked at that time, the first
22 horizontal well we drilled in the State of North
23 Dakota, we had a section 640 acres. We had a vertical
24 well here that we wanted to prove up that drilling
25 technology the one time. We were going to go ahead

1 and spud the well somewhere in this area, to the
2 proper spacing away from the lease line.

3 What the State of North Dakota said,
4 "Here's your permit, guys. If you need anything else,
5 let us know." They went ahead and took the
6 conventional, accepted radius of drainage for the
7 vertical, they backed this off, the state requirement
8 on spacing. This was our permit edge. They said, "We
9 wish you well. Keep your bit inside that area, and
10 you can produce the well at whatever it will make. We
11 wish you well getting it down."

12 What we did is, we drilled down vertical.
13 The current world record at that time was about 1,500
14 feet lateral for a medium-radius horizontal, and we
15 went from through vertical to through horizontal in
16 600 feet, and we drilled a well up like that 2603 feet
17 at 86 degrees or higher. The well came in in an area
18 that was considered to be noneconomic by the industry
19 because they had moved out. It came in at 300 barrels
20 a day. That was over two years ago. The well is
21 currently flowing on its own energy source with no
22 pumping or hydraulic lift, and is currently producing
23 about 250 barrels a day. That well has produced in
24 excess of 240,000 barrels and has an ultimate recovery
25 of around 600,000 barrels now.

1 The typical vertical in the Bakken would
2 give you about 40 barrels a day, with an ultimate
3 recovery of somewhere in the 40- to 60,000 barrel
4 range. The State of North Dakota came back, said,
5 "What else can we do to get you to continue to drill
6 these types of wells in the State of North Dakota?"
7 We did not ask for the reduction in severance tax from
8 12 to 5 percent that covers the first 18 months of
9 production, but they gave it to us anyway because they
10 wanted to see us up there.

11 We have approximately in excess of 5,000
12 barrels a day coming out of fractured Bakken shale
13 that the industry several years ago determined to be
14 uneconomic. What we're asking to do in the State of
15 New Mexico is to come in and drill two highly-deviated
16 gas wells. We're asking for a very marginal, in my
17 opinion, variance, to allow us to know what the
18 economic numbers are going to be, and then we'll take
19 the mechanical risk, we'll take the risk of not
20 getting the increased sweep efficiency we talked
21 about, and we'll take the risk on not hitting the
22 micro fracture systems that haven't been penetrated by
23 vertical drilling or wellbore stimulation. At the
24 ends of the two wells we'll come back to the
25 Commission and show you the data.

1 The thing that I guess has been the most
2 eye-opening to me today, is that some of the comments
3 I've heard have been, "Well, my God, what if you're
4 successful. If you're successful your allowable is
5 going to be too big." At Meridian Oil we want to plan
6 for success. We want to go get that five trillion
7 cubic feet. If it means you have to change some rules
8 that were written 30 years ago, we don't want to
9 dictate what the changes would be, but we want to be a
10 part of it to bring that new technology to the State
11 of New Mexico.

12 I can assure you Amoco is a good
13 competitor. Amoco is a very, very good oil and gas
14 operator, and if we drill a highly-deviated gas well
15 and we get a 16 million a day well, they're going to
16 come and offset it. Make no mistake about it. And
17 they'll be coming right back to the Commission and
18 saying, "You know, that isn't such a bad idea. Give
19 us the same deal on two wells that you gave
20 Meridian."

21 And it's not going to be long after that,
22 just as in the coal degasification, that the smaller
23 independents say it can't be that tough to do, and
24 we're either going to join the big boys until we learn
25 the technology, or we're going to go it alone. Right

1 now you can't pick up a lease in the San Juan Basin
2 that have coal underneath it, because Wallstreet, the
3 drugists, the dentists and everybody else is in here
4 to get a piece of the action.

5 I'm telling you, this is a new, different
6 type of technology that has tremendous upside
7 potential. And to put it in perspective one more
8 time, we're asking for a variance on two wells when
9 there has been 19,000 completions already. Was that a
10 long-winded answer to your question?

11 Q. I heard what you said. They didn't give
12 you an increase in the allowable, though, did they?

13 A. The State of Texas will give you four times
14 a vertical well now in the Austin Chalk. A vertical
15 well drilled to that depth will get somewhere about
16 300 barrels per day on 80-acre spacing. They allow
17 OREX, not Meridian, but OREX, to go ahead and replace
18 four 80-acre spacing wells with one horizontal. And
19 the current allowable is 1312 barrels per day on the
20 one horizontal wellbore.

21 The State of North Dakota says produce it
22 at a maximum efficient rate, you determine what that
23 is. If somebody feels like they're being drained,
24 they have the obligation, as a prudent operator, to go
25 in and put a well down and offset that well, very

1 similar to what the industry has done in the last 40
2 years on offsetting the vertical wells.

3 Q. Do you think the fact that that's oil and
4 this is gas enters into it?

5 A. No, not at all.

6 Q. Markets don't--

7 A. No. Excuse my English, but if you go back
8 to Darcy's equation and you look at the mechanical
9 advantage you get, you should get flow volumes of 7 or
10 8 times out of the horizontal or high-angle, relative
11 to a vertical. But, in reality, we're finding out
12 you're probably in the 3 to 4 range. So, I don't
13 think the thing is going to get out of hand.

14 I think on two wells that the type of
15 arrangement that was suggested by our technical people
16 today is very reasonable, because they're willing to
17 cap that, you know, at the values discussed. And
18 we're not going to drill 600 wells like we've done in
19 the coal seam. We're going to drill two wells and
20 come back to the Commission. So the risk of being
21 successful, in my opinion, is not that much of a
22 threat to the other producers.

23 Q. Would you share the information from these
24 two wells with the public?

25 A. We'll follow the same course and procedure

1 we did on coal seam degasification. We think if we're
2 going to take the risk up-front, mechanically and
3 financially, that we should have a certain amount of
4 time to fine-tune that technology. But it's my
5 opinion that in 18 to 24 months everybody can follow
6 suit, if they should so desire.

7 I think that's what we've demonstrated in
8 coal degasification. You have people running the
9 preperforated liners, you have them creating the
10 pressure sinks. The best example would probably be
11 Blackwood & Nichols and a couple of the smaller
12 independents that have moved in, and they have the
13 benefit of the hundreds of million dollars that we've
14 invested to prove this project up to industry.

15 The California customers said it won't
16 work. You had other majors that said it wouldn't
17 work. Our respected Amoco over there said that our
18 technology would only give you short-term volumes and
19 it wouldn't last over a period of time. I think now
20 that our competitor is taking a look at their
21 technology and ours, and I think they'll be doing some
22 of both in the future.

23 So there's no way that one independent--and
24 that's what we are--there's no way that one
25 independent is going to have a captive grasp of this

1 new technology we're trying to bring to the San Juan
2 Basin. There's no way we could hold that tight.

3 Q. You don't publish it as such, do you?

4 A. No. We've been on the cover of The
5 Petroleum Engineer, World Oil, The Oil & Gas Daily
6 Investor, and other publications with our data on
7 horizontal drilling, and with our data on coal
8 degasification.

9 MR. WEISS: Thank you.

10 EXAMINATION

11 BY CHAIRMAN LEMAY:

12 Q. Mr. Clayton, in the Williston, they put the
13 Bakken horizontal in 640's up there, didn't they?

14 A. They have just recently changed those
15 rules. We're drilling on 320's. The industry went up
16 there and leased up a lot of land without intending to
17 drill, and they wanted to drill one well on 640's not
18 to get the rigs running but to hold the acreage until
19 they could cut a deal.

20 The State of North Dakota, on December 19,
21 1989, changed the rules to read that you're allowed to
22 drill up to four wells on a 640. What they're saying,
23 if you want to drill one, go drill one. If there's
24 another operator that thinks the maximum efficient
25 drainage pattern is 160, he can drill four.

1 Q. There are no allowables in the State of
2 North Dakota, are there?

3 A. No, sir. You have some restriction on the
4 gas that's allowed to be flared, so there is a delay
5 until you get your pipeline, but it's temporary
6 restriction until you can sell that natural gas.

7 Q. On the vertical hold, was the Bakken in
8 40's before you came into the horizontal--

9 A. It's my understanding that they had some
10 drilled on less than 40's. You either hit the
11 fractures or you didn't. If you hit the fracture you
12 made a well. If you didn't, you had a dry hole. And,
13 consequently, when you did full-cycle economics on 10
14 wells, 20 wells drilled, you were losing money until
15 this technology was proven.

16 CHAIRMAN LEMAY: That's all the questions I
17 have, thank you.

18 THE WITNESS: Thank you very much.

19 MR. KELLAHIN: Mr. Chairman, that concludes
20 our presentation.

21 CHAIRMAN LEMAY: Thank you, Mr. Kellahin.
22 Do you have any witnesses, Mr. Lund?

23 MR. LUND: I think you indicated earlier
24 you would like to hear some of the production data and
25 things like that, and we're prepared to present that

1 for you.

2 CHAIRMAN LEMAY: I'll take a break for
3 lunch, if you are. I suggested that it would help the
4 Commission if you're posing the application that we
5 have some alternative recommendation. That was all.

6 MR. LUND: We do. And we do have an
7 alternative recommendation.

8 CHAIRMAN LEMAY: Okay. Well, let's take a
9 break and we'll reconvene at 1:30.

10 (Thereupon, the noon recess was taken.)

11 CHAIRMAN LEMAY: Shall we convene? I take
12 it you're through with your case, Mr. Kellahin?

13 MR. KELLAHIN: Yes, Mr. Chairman.

14 CHAIRMAN LEMAY: Amoco's case, Mr. Lund?

15 MR. LUND: We have one witness, and he's
16 previously been sworn.

17 Mr. Emmons, would you take the stand?

18 LARRY N. EMMONS,
19 the witness herein, after having been previously sworn
20 upon his oath, was examined and testified as follows:

21 EXAMINATION

22 BY MR. LUND:

23 Q. Mr. Emmons, would you please state your
24 name and your business address.

25 A. Larry N. Emmons, and business address is

1 P.O. Box 800, Denver, Colorado, 80201.

2 Q. By whom are you employed and in what
3 capacity?

4 A. I'm employed by Amoco Production Company as
5 a petroleum engineer.

6 Q. You've never testified as an expert before
7 the OCD or the Oil Conservation Commission, have you?

8 A. No, I have not.

9 Q. Briefly then, what is your education from
10 college on?

11 A. I graduated from Purdue University in 1979
12 with a Bachelor of Science in Chemical Engineering.

13 Did you want me to go into my work
14 experience after that?

15 Q. If you would, please. Since your
16 graduation from Purdue, what is your relevant work
17 experience?

18 A. I started with Amoco in 1979 in Farmington,
19 New Mexico, where I worked approximately 18 months,
20 drilling a number of wells and hydraulically
21 fracturing a number of wells and participated with our
22 research center in developing a hydraulic fracturing
23 technique.

24 Then I went to our Denver office where I
25 worked Oklahoma production from our division office.

1 I then went as an engineering supervisor to Evanston,
2 Wyoming, and worked the Overthrust area. Then to
3 Oklahoma as a regulatory engineer where I testified
4 approximately 200 times in front of the Oklahoma
5 Corporation Commission.

6 I then came back to Denver, continued in
7 Oklahoma, as well as testified approximately 40 times
8 in Kansas. And my current responsibility includes
9 Arizona, California, New Mexico, and Kansas.

10 Q. You're a Professional Engineer?

11 A. Yes. I'm registered in the State of
12 Oklahoma, and I took the test in the discipline of
13 petroleum.

14 Q. You're not the President and Chief
15 Executive Officer of Amoco Corp, are you?

16 A. I'm not currently nor have I ever been. I
17 do aspire to be so.

18 Q. Before we talk about specific points, would
19 you please give us a summary of what Amoco's position
20 is in this case?

21 A. Amoco is not opposed to the drilling of a
22 horizontal well; in fact, we're looking -- I think
23 it's called a deviated well in this case. In fact,
24 we're looking at doing the same thing. Where our
25 concern is is correlative rights. We're obviously the

1 operator of some offset units. We're concerned about
2 the main dispute here, being the doubling of the
3 allowable or doubling of the deliverability to set the
4 allowable could adversely impact the offsets, as well
5 as impact the balance of the pool.

6 We do have what we feel is a fair alternate
7 proposal. Realizing that the deviated well is in fact
8 encountering both quarter sections, it may actually
9 have the withdrawal and perform like two vertical
10 wells, since it has up to three to four times the
11 contact area. We just don't know what kind of rate
12 will come out of it, but chances are it's going to be
13 significantly higher than a vertical well. There's
14 that possibility. However, we don't feel it's
15 necessary to be as restrictive as what the original
16 order imparted on Meridian, whereby they can only use
17 the deviated well or the two vertical wells.

18 We feel it would be fair to go somewhere in
19 between; that being using any two of the three wells
20 in the unit, provided the horizontal well did
21 encounter the Mesaverde formation in both quarter
22 sections. Obviously, if they have problems with the
23 well, and it's only in one quarter section, then it
24 should be treated as a standard vertical well. As
25 long as it is underneath, encountering the Mesaverde

1 in both quarter sections, we don't care which of the
2 three wells they use to determine the allowable. They
3 can take the best two.

4 Q. Let's turn to some specific points about
5 the testimony. First, let's talk about production
6 data from offset proration units to the two proration
7 units we've been discussing. If you would, please,
8 just kind of give it in summary form. If Mr. Kellahin
9 or others want some additional details, you can supply
10 that later.

11 Let's talk first about current
12 deliverability.

13 A. I took the February 90 OCD books on the
14 Mesaverde formation and looked at current
15 deliverabilities, which is different from what was
16 presented in, I believe, Exhibit 3.

17 I believe Exhibit 3, if they had the latest
18 test, they used it. If they didn't, they used what
19 was the previous test. I don't think that's fair in
20 that you're really kind of comparing apples with
21 apples because the offsets that they didn't have data
22 for may have also had their deliverability dropped.

23 What I determined is that if you look at
24 the -- specifically, on the Howell section and compare
25 that to the offsets, the highest unit deliverability

1 in and around the Howell unit is 2,073 Mcfd, whereas
2 the minimum is 386 Mcfd, while the Howell "E" itself,
3 using the same vintage of data, was 773 Mcfd. So it
4 was by no means the poorest unit, but it wasn't the
5 best unit either.

6 However, if deliverability is the problem,
7 drilling another vertical well could alleviate that
8 problem because the vertical well may have a higher
9 deliverability, and therefore improve the
10 deliverability out of the unit.

11 Q. Mr. Emmons, I think maybe the Meridian
12 witness testified that the deliverability for the
13 Howell "E" was lower. What do you have to say
14 about that?

15 A. I believe he testified it was 531, yet that
16 was because -- and I don't have Exhibit 3 in front of
17 me, but I believe on the Howell E 2, he had something
18 less than around 150 Mcfd range. He had -- in
19 November 1990 deliverability books, it shows that
20 should actually be 428 Mcfd.

21 Q. Let's talk about the current deliverability
22 in the Riddle section and the offsets.

23 A. The Riddle section, the offset units had a
24 maximum rate or maximum unit deliverability of 2,612
25 Mcfd, a minimum rate which was 176 Mcfd, while the

1 Riddle itself had a deliverability of 741. And I
2 don't believe there's an exhibit showing that, but
3 what it shows there is, again, the Riddle section is
4 not the poorest unit in the area, nor is it the best.
5 Again, they can alleviate those problems by drilling
6 another vertical well and therefore getting a higher
7 deliverability.

8 Q. Let's talk for a little bit about
9 cumulative production data. Would you please give us
10 a summary of what your conclusions are about that in
11 these particular proration units.

12 A. Without going into a lot of detail on the
13 production -- I can, if that's desired, but, in
14 general, if you look at the Howell unit and look at
15 the production of the Howell unit compared to the
16 surrounding offsetting units, their production to date
17 has been approximately 150 percent above or 150
18 percent of the production of the average of the
19 offsets. That being if you took the production of all
20 the offsets and got an average for them, the Howell
21 unit is actually doing about 50 percent better.

22 Q. What about the Riddle unit?

23 A. The Riddle unit, unfortunately, I didn't
24 bring all the data with me, but I looked at the units
25 that were to the east and to the west, as well as to

1 the south, and that came up with the Riddle unit
2 producing at 130 percent of the average.

3 Q. So based on your analysis of the current
4 deliverability data and the cumulative production
5 data, do you think that the two units that Meridian
6 has been discussing are suffering under any kind of
7 competitive disadvantage?

8 A. I don't believe so.

9 Q. Let's talk a little bit about the two times
10 deliverability factor that has been introduced by
11 Meridian. Do you have an opinion as to whether that
12 two times deliverability factor would protect the
13 offset owners' correlative rights?

14 A. Yes, I do. I feel that the deliverability
15 factor is a special exception that does not protect
16 the offset unit's correlative rights for a variety of
17 reasons. Basically, that special exception is not
18 given to any other unit or any other well within the
19 Blanco-Mesaverde field.

20 By taking only a single well and doubling
21 that, you've taken out an implied limitation in the
22 proration formula. If you get a tremendous well in
23 one quarter section, you're forced to put that width
24 -- your well in the other quarter section which may
25 not have similar permeability, porosity, or production

1 characteristics. So you're not able to take your best
2 well and double it. You're forced to average it down
3 by incorporating one of the four wells.

4 Also, I expect that the deviated well will
5 have a higher deliverability because it has quite a
6 bit more formation contact. The entire purpose of the
7 deviated well is to have a better opportunity to hit
8 permeable sands, and if they do so, you would expect a
9 higher deliverability.

10 For the offset operators, there's the
11 thought that the offset operators have the same
12 ability to protect themselves by drilling horizontal
13 wells. Unfortunately, that forces the offset
14 operators to abide by someone else's economics. It
15 forces us to drill a horizontal well or a deviated
16 well, which is more expensive, when in fact a vertical
17 well may accomplish the same goal, but in order to get
18 the allowable exception, we would be forced into
19 drilling a deviated well.

20 Q. Let's talk a little bit about Meridian's
21 suggestion that a production cap be placed on
22 deliverability for the deviated wellbore. Do you have
23 an opinion as to whether that is fair and protects
24 Amoco's correlative rights?

25 A. The cap is based on the highest

1 deliverability in the entire pool. Obviously, that
2 doesn't have anything to do with the surrounding
3 units. The surrounding units don't have anywhere near
4 the capability -- the immediate surrounding units
5 don't have anywhere near the capability of what the
6 highest units in the pool make.

7 Also, they're using the -- I think, to
8 demonstrate that, I believe they mentioned they're
9 using the Amoco's Fields LS2A, which is in Section 25,
10 32 North, 11 West, which is two to three townships
11 away from this area; so I don't feel that's a fair
12 comparison.

13 One thing I'd like to add, these units do,
14 even though they may have initially a high rate, they
15 do fall. The current 1990 test on the Fields 2A
16 that's been recently filed with the Conservation
17 Division has a unit deliverability of 2,870 Mcfd; so a
18 significant drop in it.

19 We don't know whether retest will increase
20 that rate or not, but that shows you the kind of
21 variation you can have in a unit. But what Meridian's
22 cap does, it says, if you have that kind of drop on
23 that unit, they want to switch to a different unit.
24 The proration formula has its natural protection
25 mechanism in, whereas if you have an extremely good

1 unit that produces a lot of gas, its pressure should
2 drop; therefore, deliverability should drop; and,
3 therefore, it drops down and helps protect the offset
4 unit. But with this cap, they want to switch to a
5 different unit that may not have had the same
6 drawdown.

7 Q. So Meridian is not willing to live with the
8 natural production decline in this particular field?

9 A. Not based on the cap.

10 MR. LUND: Mr. Chairman, it just occurred
11 to me, I may not have asked to qualify Mr. Emmons as
12 an expert petroleum engineer.

13 CHAIRMAN LEMAY: His qualifications are
14 acceptable.

15 MR. LUND: Thank you. I apologize.

16 Q. Let's talk about some miscellaneous
17 points. You and I discussed the testimony, and we
18 would like to make a few more points.

19 Let's talk first about the fracturing of
20 wells. I think Commissioner Weiss asked about
21 fracturing wells in this area, and whether they get
22 any special treatment in terms of a special allowable
23 or anything like that. Based on your study, what's
24 your opinion about that?

25 A. No. To my knowledge, even though great

1 dollars are spent on hydraulically fracturing wells,
2 especially when the technology was new -- I was
3 working the San Juan Basin when we were doing that. I
4 participated at the research center. We did many
5 fracs where we had expensive gauges. We had a lot of
6 time spent on an individual well just to build the
7 data. So we spent a lot of dollars; yet I don't
8 believe any special allowable exceptions were made on
9 those wells.

10 Q. What about economics? There was some
11 testimony this morning from the Meridian witnesses
12 about their economics. What's your opinion about
13 their economics vis-a-vis other producers in the area?

14 A. The problem I have with the economics,
15 obviously, they want a special exception to the
16 allowables to make it a profitable venture.
17 Unfortunately, that doesn't necessarily tie to the
18 correlative rights of the offsets.

19 As a matter of fact, as I look at their
20 economics, I think they made a pretty good case that
21 they should be drilling vertical wells instead of
22 horizontal wells. It shows they really have to have a
23 tremendous rate on the well in order to make a
24 deviated well pay out. Maybe they can accomplish the
25 same results by drilling vertical wells.

1 Q. There were some other questions this
2 morning I think from Chairman LeMay and from
3 Commissioner Weiss about whether these deviated
4 wellbores would hit virgin pressure areas or pressure-
5 depleted areas. What's your opinion on those
6 particular issues?

7 A. There's always that possibility. It's a
8 heterogeneous reservoir. So I agree that there is
9 that chance, and that's the whole reason we're
10 concerned about the double allowable. However, one of
11 the exhibits that was presented on the Scott P/Z
12 curve, it was stated they drilled a replacement well
13 right next to their original well, and it came in at
14 the same pressure. That shows to me that they aren't
15 generating new reserves. Granted, they did get
16 reserves faster, but they weren't new reserves. They
17 were reserves that were probably going to be recovered
18 by an offset well because it's been pressure depleted.

19 Q. Mr. Emmons, there was also some testimony,
20 I believe, from Mr. Jones about the proration formula
21 and when wells get shut in. That appears to be an
22 issue in this hearing. What's your opinion about the
23 offsets having to live with those proration rules
24 vis-a-vis Meridian's proposal in this case?

25 A. If you look at Exhibit 13, I believe that

1 will apply to any well, the proration formula. If
2 they drilled a vertical well, they would have the same
3 limitations. That is part of the proration formula,
4 and that's part of the protection of the proration
5 formula. They're asking for a deviation from that to
6 pay out their well, and I don't feel that's protecting
7 correlative rights.

8 Q. There was also some discussion about oil
9 wells versus gas wells and drainage and things like
10 that. What are your thoughts about that particular
11 issue in the hearing?

12 A. I don't feel comfortable in making general
13 comparisons between gas and oil. I feel you have
14 different market considerations, different production
15 mechanisms. The Conservation Division even treats
16 them differently. You've got a prorated Mesaverde
17 field. It's not fair to compare it to an unprorated
18 oil pool. Your drainage patterns are different.
19 Spacing unit sizes are different. So I don't think a
20 general comparison is fair.

21 Q. Let's talk next about Mr. Clayton's
22 diagram. We had it up on the board, but maybe you
23 could step to the board and redraw it. It seems to be
24 missing. I know you had a few thoughts about that.
25 Would you go ahead and do that?

1 A. I'm not a draftsman either; so I'll just do
2 my best.

3 Q. You'll have to describe orally as you go
4 because the court reporter won't have that in front of
5 her.

6 A. Okay. I'm simply trying to recreate Mr.
7 Clayton's exhibit, which is a representation of a
8 section divided into quarter sections. Even though
9 this specific case deals with stand-up units, this
10 picture deals with a lay-down unit in the south half.

11 He drilled a wellbore in the center of each
12 quarter section in the south half, representing two
13 vertical wells. If I remember correctly, he drilled a
14 vertical well that started up in the north and then
15 intersected both vertical wells by continuing from the
16 west half into the east half.

17 He then drew a circle around each vertical
18 well, and this is supposed to be a circle
19 (indicating), representing a drainage pattern that
20 incorporated most of the section -- most of each
21 quarter section that would be observed by the vertical
22 wells.

23 By drilling the deviated well, he then
24 connected by tangent the ends of the drainage pattern
25 of the vertical wells and then shaded in the area,

1 showing that that would be what would be produced by
2 the deviated well that could not be produced by the
3 vertical wells.

4 Q. That apparently was part of his figure of
5 15 percent additional ultimate recovery?

6 A. Right. I believe he attributed 10 percent
7 due to that. That doesn't directly apply here because
8 the Mesaverde is segregated, and, actually, they're
9 only going to get, I believe, in one portion of it,
10 the Cliff House, and another portion, Point Lookout,
11 where that same limitation is placed on vertical
12 wells.

13 But the key point I'd like to make is that
14 by drilling a horizontal well, there is an implied
15 location exception that they do not have to be 130
16 feet from the center of the unit boundary. If you
17 take that implied restriction away and drill your
18 third vertical well right in the center, you're going
19 to recover a majority of the reserves that would have
20 been recovered by the horizontal well.

21 Another thing I'd like to point out, this
22 deals with -- here I'm erasing everything except
23 what's in the -- what would be the drainage pattern in
24 a vertical well in the west half.

25 Although the deviated well is projected to

1 go into the other quarter section, there is no way
2 they will be able to govern where the permeable zones
3 are. Obviously, for them to get the drainage that
4 they would desire, hopefully, you have a homogeneous
5 reservoir, and you have homogeneous permeability, and
6 therefore it's all going to be produced equally.
7 Unfortunately, the Mesaverde doesn't necessarily do
8 that.

9 You may actually have one highly permeable
10 zone in the Mesaverde. And that very well could be a
11 single point. You could have an extremely permeable
12 zone. And so the first several years of production
13 out of that well may act as a vertical wellbore.
14 Therefore, it would be unfair to give this unit twice
15 the allowable --

16 Q. And also if you hit --

17 A. -- twice the deliverability.

18 Q. Also if you hit a highly permeable zone in
19 one quarter section, what effect, if any, would that
20 have on its drainage radius?

21 A. Graphically, instead of having -- if, in
22 fact, this turned out to be the permeable area, if you
23 give it twice the deliverability, then it's going to
24 have twice the drawdown from this area; so your
25 drainage area then goes beyond what was being depicted

1 by the original circle.

2 So if your vertical well would have
3 recovered the entire quarter section, the horizontal
4 or deviated well could recover from beyond the unit.

5 Q. If you would, please, just sum up what
6 Amoco's position is and what its proposal is in this
7 case.

8 A. Amoco is concerned about the correlative
9 right impact by doubling a single deviated well's
10 deliverability and applying that to the allowable. We
11 feel a proper alternative and a better alternative in
12 the interest of protecting the offset's correlative
13 rights would be to allow Meridian to take the two best
14 wells and then have those two best wells determine the
15 allowable for the unit.

16 We do not care whether they use the
17 horizontal well plus either of the two vertical wells,
18 or if the deviated well turns out to be a poorer well,
19 they would then use the conventional method of taking
20 the two vertical wells. The only restriction I place
21 upon that, again, is the deviated well should
22 encounter Mesaverde formation within both units --
23 within both quarter sections.

24 Q. Is it Amoco's intention to discourage or
25 prohibit Meridian's ability to drill these deviated

1 wells?

2 A. Not at all.

3 MR. LUND: I have nothing further, Mr.
4 Chairman.

5 CHAIRMAN LEMAY: Thank you, Mr. Lund.
6 Mr. Kellahin?

7 MR. KELLAHIN: Thank you, Mr. Chairman.

8 FURTHER EXAMINATION

9 BY MR. KELLAHIN:

10 Q. Mr. Emmons, this case originated before the
11 Examiner in a hearing on September 20, 1989. Are you
12 aware of that?

13 A. Yes.

14 Q. You've read the order?

15 A. I've read the transcript, and I've read
16 portions of the order.

17 Q. When did you personally become involved in
18 your company's position in this case?

19 A. Prior to -- well, when we first picked up
20 the case on the docket before the initial hearing.

21 Q. Am I correct in understanding that your
22 concerns are with regards to correlative rights'
23 issues as they might apply to Amoco's spacing units in
24 the Mesaverde that offset the two project areas?

25 A. Although obviously I'm here to protect

1 Amoco's interest, but I'm also concerned about
2 correlative rights in general and the direct offsets.

3 Q. Within the context of the issues decided
4 before the Commission, they look to the prevention of
5 waste, and they also look to the correlative rights'
6 issues.

7 A. Correct.

8 Q. Within that, you have not expressed any
9 opinions or objections with regards to this pilot
10 project preventing waste? Your concern, as I
11 understand it, is the correlative rights impact that
12 this project allowable may have on you as an offset
13 operator?

14 A. Actually, you can tie it back into waste.
15 If I, as an offset operator, am forced into drilling
16 expensive deviated wells simply to get an allowable
17 relief when I can accomplish the same thing with
18 vertical wells, then it has caused me economic waste.
19 You're protecting correlative rights through a
20 wasteful action.

21 Q. The prevention of waste concepts that are
22 integrated in the Examiner order are ones that he has
23 predicated on findings that show that the deviated
24 well has got the opportunity to encounter reserves
25 that the two existing wellbores do not encounter. You

1 don't have any disagreement with that notion, do you?

2 A. No, sir, but the vertical well may be able
3 to do the same thing.

4 Q. I guess I'm confused by your position.
5 Amoco is not in opposition to the utilization of the
6 pilot project for highly deviated wellbores, are you?

7 A. No.

8 Q. You're not taking the position that we can
9 accomplish the same thing with vertical wells and
10 therefore should not have the opportunity to drill the
11 two pilot wells?

12 A. Correct. I don't know that anyone knows
13 whether you can accomplish the same thing with a
14 vertical well, but at this time I think a deviated
15 wellbore is a good concept to pursue.

16 Q. Describe for me the basis by which you are
17 concerned about correlative rights.

18 A. In what manner? I think I --

19 Q. In any manner you choose, sir.

20 A. I think I stated several reasons. I think
21 I just restated one. In order to get a similar
22 allowable relief in the offsets, the offset operator
23 will be forced into drilling horizontal wells. I
24 don't believe that the OCD will grant twice the
25 deliverability on another vertical well.

1 So you have the economic waste in order to
2 protect against a horizontal well, if it turns out to
3 be a good well.

4 Q. Your basis assumes that the highly deviated
5 well is going to be more successful in terms of having
6 a higher deliverability than the third vertical well;
7 right?

8 A. I think that's the whole -- it does, but I
9 think that's the whole reason it's being drilled. I
10 don't think if you were going to get a poorer well,
11 you would drill it.

12 Q. What if the Commission disagrees with you
13 and decides to offer Meridian twice the deliverability
14 of the highly deviated well and establishes a cap.
15 Now, you and Mr. Lund have talked about the cap.

16 A. Um-hm.

17 Q. Do you have a recommendation as to where to
18 place that cap in the event the Commission disagrees
19 with your proposal that we don't use twice the "D"?

20 A. I can't support that option because I've
21 already explained all the reasons why I don't support
22 the option. I guess I have a problem answering your
23 question because that's not an option that I want to
24 pursue.

25 Q. I understand it's not. Let's talk about

1 your reasons to object to the cap. You'll concede
2 with me, won't you, that the highest deliverability in
3 the Mesaverde is a well that you operate that's got 16
4 million a day?

5 A. I don't believe you'd call it the highest
6 based on the current test.

7 Q. Let's assume that's approximate, 16 million
8 a day; all right?

9 A. Okay. That's incorrect, but that's fine.

10 Q. And that's permitted under the allowable
11 system that we have now?

12 A. Correct.

13 Q. We have a deliverability-driven allowable
14 system?

15 A. Correct.

16 Q. There are no special limitations on that
17 well even if it was the third well in the spacing unit
18 that had -- this big horse in the reservoir that's got
19 this humongous amount of gas it produces every day;
20 it's not restricted, is it?

21 A. No. However, its current test is less than
22 3 million a day. So it's gone from 16 to 3 million,
23 and yet under the proposed cap, then they would switch
24 -- Meridian would then switch to the next best unit.
25 So you aren't comparing apples with apples there.

1 Q. Let's see if we can find some apples. Do
2 you have a copy of Meridian's exhibit book?

3 A. I'm afraid I don't.

4 Q. Let me find one for you. (Indicating.)

5 Let me have you turn to page 3 of the
6 Meridian exhibit book, Mr. Emmons.

7 A. Okay.

8 Q. If you'll look in the lower left-hand
9 corner in Section 22, look at the 86 statewide
10 deliverability on the Howell K 2A well; do you see
11 that?

12 A. Yes.

13 Q. 12.4 million a day, is it?

14 A. Yes.

15 Q. Look at the offsetting spacing unit that
16 Amoco has, the Florance 45, a little over a million a
17 day?

18 A. That's correct.

19 Q. If we're looking for places to peg a cap,
20 here's one within a section of the subject spacing
21 unit, and it shows 12.4 million a day; right?

22 A. That's the deliverability, yes.

23 Q. When we look at the advantage that one well
24 enjoys over another in Section 22, there is a
25 significant range of dissimilarities between the two

1 deliverabilities, isn't there?

2 A. Today. That may not happen tomorrow.

3 Q. And if this cap is allowed to float, as Mr.
4 Jones proposed, then what you're doing is restricting
5 the allowable rate on the highly deviated well to what
6 actually occurs in the reservoir of this particular
7 pool, don't we?

8 A. Yes. I have a problem with your term
9 "float." I've already shown you where it should have
10 floated from 16 to 3 million, and you just floated
11 over to 12.4 million. So it's not the same thing as
12 your taking a single unit and abiding by the natural
13 corrective processes within that unit.

14 Q. Isn't your concern that there's going to be
15 some net uncompensated drainage from the Amoco
16 property to the Meridian because they're going to put
17 this big horse right next to you, and it's going to
18 take your share of the gas? Isn't that what you're
19 trying to worry about?

20 A. I don't have a problem if Meridian does
21 that and can comply with the current proration
22 formula. Where my problem is is that Meridian is
23 trying to go beyond the proration formula and ask for
24 a special provision to allow a higher allowable. To
25 get to that cap, they're going to have to get 8

1 million a day out of their well.

2 I don't see any wells in the immediate
3 offsets units, and when I'm saying "immediate," I mean
4 directly offset units, that come anywhere near 8
5 million a day in a deliverability out of a single
6 well. And so --

7 Q. Then you're telling me if we take twice the
8 "D," we're really giving it an artificial allowable
9 that any well in this area can't expect to meet?

10 A. Let's use an example, Section 22. My
11 answer is possibly.

12 Look at Section 22. The very example you
13 gave me, it had a rate of 12.4 million a day for its
14 deliverability. Look at the other wells in that same
15 unit that it has to combine with it. It's 413. It's
16 not that -- that well could have come in at 8 million
17 and had the other well in the unit be 413. It would
18 still be limited to 8 million a day. What you're
19 asking for is 16 million a day.

20 Q. Isn't the underlying concern one where
21 you're worried about the allowable for the highly
22 deviated well enjoying some unfair competitive
23 advantage over Amoco whereby there is net
24 uncompensated drainage from your spacing unit to ours?

25 MR. LUND: I object to the question as far

1 as net uncompensated drainage. It calls for a legal
2 conclusion. I have no objection to Mr. Emmons
3 testifying about what his understanding of drainage is
4 in general.

5 CHAIRMAN LEMAY: I'm not sure where you're
6 going, Counselor, on this.

7 MR. KELLAHIN: Let me rephrase the
8 question.

9 Q. You're worried, aren't you? Correlative
10 rights means what to you, sir?

11 A. As Mr. Jones mentioned earlier, the
12 opportunity to produce your fair share of the
13 reservoir.

14 Q. Without waste?

15 A. Without waste.

16 Q. Your share is defined, I presume, by some
17 volume of gas that underlies your spacing unit?

18 A. Generally, yes.

19 Q. You have expressed concern over the cums
20 that have been produced within the areas around the
21 Howell well; right?

22 A. Right.

23 Q. Can you tell me what percentage of the
24 total gas in place for the spacing unit that that
25 cumulative number represents for any of the spacing

1 units?

2 A. I would have to share some of the same
3 concerns that the geologist presented; that it is
4 difficult to map the area. Quite often, the four
5 volume numbers and the P/Z numbers do not compare. So
6 to compare it directly to gas in place, Amoco has the
7 same concerns that Meridian has.

8 Q. I assume then by your answer that you have
9 not attempted to calculate volumetrically the
10 recoverable gas in place either under the Howell unit
11 or any of the other spacing units that might offset
12 that spacing unit?

13 A. That's correct.

14 Q. And that's true of the Riddle as well?

15 A. Correct.

16 Q. Have you as a reservoir engineer attempted
17 to construct a P/Z versus Q plot on any of the
18 producing wells in this particular area for the Howell
19 or the Riddle?

20 A. No, I have not.

21 Q. So based upon that analysis, you can't tell
22 me what you would project to be the ultimate recovery
23 from any of those wells?

24 A. I have looked at some P/Z analysis for the
25 two units involved.

1 Q. Can you tell me what portion of the current
2 cumulative production from any of those wells is
3 related to the gas volumes you get from the P/Z
4 analysis?

5 A. I'm not sure what you're asking me.

6 Q. You told me you haven't done volumetrics to
7 give us gas in place or recoverable gas for any of the
8 spacing units?

9 A. Correct.

10 Q. Have you taken the methodology of looking
11 at P/Z to get you cumulative gas from that particular
12 well?

13 A. I have looked at the P/Z curves on the
14 wells.

15 Q. Is the basis of your opposition based upon
16 ultimate recoveries per spacing unit, using the P/Z
17 analysis?

18 A. I didn't do the type analysis you're
19 asking. What I did is I looked at what has been
20 recovered to date. And if you can't do poor volume
21 analysis, you can't really relate it back to what's in
22 the ground. You're just looking at what's happened to
23 date.

24 And based upon your deliverability test
25 data, which I addressed in my first comment, that

1 problem can be overcome by drilling a vertical well.

2 The other comparison I made was to
3 production to date. Clearly, the Howell and the
4 Riddle have not had a disadvantage in getting the
5 amount of production out of the ground when you
6 compare their unit to the offset units.

7 Q. Does Amoco have plans to drill any highly
8 deviated or high-angle wells in the Mesaverde
9 formation?

10 A. We're evaluating it.

11 Q. What is the status?

12 A. I don't know -- you know, I can't say we're
13 going to drill a well within a month or three months
14 or a year, but I know that's being evaluated.

15 Q. What is the status of the evaluation at
16 this point?

17 A. I don't really know.

18 Q. You don't know where you are on the process
19 within the company of deciding whether you'll go
20 forward?

21 A. No.

22 Q. I presume, because you don't have such an
23 application, that you're some distance removed from
24 where Meridian is at this point in their project?

25 A. I do not work the Blanco-Mesaverde field.

1 The parties -- the engineers that work that have
2 obviously a lot better handle on that.

3 Q. Do you know what your engineers that work
4 this particular reservoir and are involved in studying
5 the high-angle wells, what they're proposing to do
6 about the allowable for Amoco?

7 A. I reviewed in detail -- obviously, if this
8 is something Amoco is going to turn around and ask
9 for, it would be foolish for me to come in and protest
10 it. I reviewed in detail whether the recommendation
11 we are proposing is something we are willing to live
12 with. And the answer was yes.

13 Q. Simply because the current allowable system
14 doesn't have provision for an allowable for a highly
15 deviated well doesn't preclude the Commission from
16 creating a special project allowable for these wells,
17 does it?

18 A. No.

19 Q. There are no other highly deviated wells
20 such as this that you're aware of in the Mesaverde
21 Pool, are there?

22 A. Not to my knowledge.

23 Q. Certainly not in the San Juan Basin; right?

24 A. I can't answer for a large area but for the
25 Blanco-Mesaverde. I can answer that I don't know of

1 any others.

2 Q. Does your company have any well like this
3 in any other of the producing pools in the San Juan
4 Basin?

5 A. We've drilled horizontal -- not in the San
6 Juan Basin; I'm sorry.

7 MR. KELLAHIN: Thank you, sir.

8 CHAIRMAN LEMAY: Thank you, Mr. Kellahin.
9 Additional questions? Mr. Weiss?

10 FURTHER EXAMINATION

11 BY COMMISSIONER WEISS:

12 Q. Is Amoco satisfied with the method that
13 Meridian uses to publicize, say, their efforts in the
14 coal gas, their development techniques and such and
15 their completion techniques or their technology in
16 general?

17 A. Unfortunately, though I am responsible for
18 New Mexico, the one area in New Mexico I'm not
19 responsible is coal D gas. I know that Mr. Nance, who
20 is sitting in the audience, was in our office in
21 Denver yesterday talking about that, but to say
22 whether we're satisfied or not, I can't answer that.

23 Q. I have one other question. I guess I'm
24 confused on this cap. Maybe you can explain it to
25 me.

1 If this proposed well would make -- had a
2 "D" of 20 million a day, it would only be allowed to
3 produce 16 million is the way I understand it?

4 A. Or whatever is the highest. If Meridian
5 goes and drills a well tomorrow that comes in at 50
6 million based on their cap, the cap would then go to
7 50 million a day.

8 But to answer your question directly, yes.

9 Q. So it's based on the best well in the
10 field?

11 A. Best unit. It's a little confusing, but I
12 think they meant the best unit production out of a
13 vertical drilled unit.

14 COMMISSIONER WEISS: Thank you. That's all
15 the questions I have.

16 FURTHER EXAMINATION

17 BY CHAIRMAN LEMAY:

18 Q. Mr. Emmons, do you happen to know if Amoco
19 happened to have a policy on granting maybe an
20 incentive allowable for encouraging new technology and
21 balancing the risk encountered in using that new
22 technology?

23 A. I don't have any knowledge firsthand. They
24 may; they may not, but I don't have any knowledge on
25 that.

1 Q. Would you care to comment on regulatory
2 approaches that do encourage new technology through
3 allowable increases?

4 A. I think that has a lot of merit.
5 Unfortunately, here, we're talking about a prorated
6 pool that not only Meridian but also Amoco has
7 concerns about how the allocations are currently being
8 handled. I'm participating as well as Meridian is
9 participating on a subcommittee that's part of the
10 overall committee, trying to make changes in the
11 rules.

12 That very well could be brought up as a
13 recommendation, and let's change it for the entire
14 pool instead of doing it on a special exception basis,
15 well by well or unit by unit.

16 I guess my feelings are, let's make sure we
17 look at the entire pool and make sure it's fair to the
18 entire pool. What I tried to do is point out today
19 some of the concerns I have when you apply it in a
20 limited nature.

21 Q. Extending that, though, it has to start
22 somewhere, doesn't it? If you're going to apply an
23 incentive allowable somewhere that would be a policy
24 throughout that pool, you would start with an
25 application, I would assume?

1 A. But you may be providing an incentive
2 allowable by just making them use the horizontal well
3 plus one of the other wells.

4 I haven't heard them say they won't drill
5 it if they take our proposal. That was asked. I
6 don't believe we got a direct answer on it. So you
7 may in fact -- they expect to get a better well.
8 There's no question. If they don't, then I don't
9 understand why they're here.

10 So you may be in fact providing that
11 incentive allowable because, if the well acts like two
12 vertical wells, and you throw in another one of the
13 vertical wells, you provide them an incentive
14 allowable adding in one of the other vertical wells,
15 essentially taking three vertical wells and adding
16 them together.

17 Q. Was it your testimony that no one knows if
18 a diagonal well will increase the ultimate recovery
19 from the proration unit?

20 A. What I'm saying is, I agree with Meridian
21 that there's a lot of unknowns today. If their
22 deviated well does not encounter any better
23 permeability than what a typical vertical well would
24 get, then they may not have any positive results from
25 it. But I think there's also the same likelihood they

1 may encounter new sands; therefore, have additional
2 recovery, but that may have also been accomplished by
3 drilling another vertical well.

4 I just don't know enough about it today to
5 say in advance whether they're going to get additional
6 reserves or not. I think there's a chance that they
7 will.

8 Q. In that same vein, if you say another
9 vertical well, you would be amenable to allowing three
10 wells in a proration unit and having the operator be
11 able to choose the best two out of the three, if he
12 was so inclined, to increase his ultimate recovery?

13 A. The deviated well throws in kind of a kink
14 in that. The reason I'm not limiting Meridian with
15 the deviated well is because I think there's probably
16 a good chance that they will not get all the
17 production out of both quarter sections. They may
18 actually get the predominant production out of a
19 quarter section. Without forcing Meridian to go in
20 there and test to find out really where their
21 production is coming from, we don't know which well to
22 pair it up with.

23 So to remove that obligation, I'm saying
24 they can use the horizontal well plus any of the other
25 two. That's not to say that I think when we start

1 drilling three vertical wells in a unit that they have
2 to not include the offset unit -- an offset quarter
3 section. I still feel that's a proper requirement.

4 CHAIRMAN LEMAY: I have no further
5 questions. Thank you.

6 Any additional questions of the witness?
7 If not, he may be excused. Thank you.

8 MR. LUND: We have nothing further, Mr.
9 Chairman.

10 CHAIRMAN LEMAY: Are there any statements
11 in this case? Do you care to wrap it up, Counselor?

12 MR. KELLAHIN: Mr. Chairman, I don't know
13 if the Commission has additional questions. We have a
14 number of technical people that can quickly respond if
15 there's any further questions. I don't presume to
16 know what is of concern to you in the case. We've
17 done what we can to give you the background
18 information. If there's other information you want
19 from us or want to recall a witness, we certainly
20 still have them available.

21 CHAIRMAN LEMAY: Let me check with
22 Commissioner Weiss. We keep that option open, as you
23 know.

24 I think with the incorporation of the
25 record of the previous case and what we've heard today

1 that we certainly have enough evidence to make our
2 decision, Counselor.

3 MR. KELLAHIN: We're ready to conclude
4 then, Mr. Chairman.

5 CHAIRMAN LEMAY: Let's conclude.

6 MR. LUND: We've all heard enough today,
7 and the only point that I would make, with all due
8 respect to Meridian, I think that they have a very
9 good idea, and I understand their technological
10 concerns, but what they want to do is cherry pick, and
11 I know that was objected to earlier when I suggested
12 that. They want to get a production cap, and they
13 come in here and say, "Well, we're going to give the
14 Commission something that we did not give Mr. Catanach
15 the opportunity to consider. We're going to put this
16 production cap in there." But it's cherry picking,
17 and it's unfair for the reasons that Mr. Emmons
18 testified.

19 We do not oppose the technology. We do not
20 oppose this project. We think it's a great
21 suggestion. But it's unfair to the offsets. It's
22 unfair to those who are concerned about correlative
23 rights to allow Meridian to get what they're asking in
24 this case.

25 The final thing I would say is that I think

1 Mr. Catanach in his order very appropriately summed up
2 our concern. In his Findings 12 and 13, he talked
3 about the concerns for correlative rights and the
4 unfair advantage that Meridian would be seeking in
5 this case. And for the reasons that Mr. Emmons
6 testified to, we respectfully request that their
7 request be denied, and that you adopt the proposal
8 that Amoco has suggested. We think that would give
9 them a fair opportunity to generate a return for the
10 dollars that they've been spending and also protect
11 correlative rights.

12 With all due respect, it's simply not fair
13 to grant the Meridian request as stated today. Thank
14 you.

15 CHAIRMAN LEMAY: Thank you, Mr. Lund. Mr.
16 Kellahin?

17 MR. KELLAHIN: Gentlemen, Mr. Lund wants
18 you to focus on correlative rights. He says it's
19 unfair. It somehow gives us an unfair advantage over
20 Amoco; yet, despite their involvement in this case
21 from September onward, they have provided you nothing
22 by which to determine the extent of their correlative
23 rights and to what extent you must protect them. They
24 have not given us what they believe to be the gas in
25 place underneath their spacing units, or why the

1 establishment of a special project allowable should
2 somehow be unfair to them.

3 The concern that we have is that Mr.
4 Catanach has also put the wrong emphasis on what he
5 was doing when he wrote the Examiner order. The
6 fundamental obligation of the Commission and the
7 Examiner is to prevent waste. It is not simply to
8 look solely at the correlative rights issue;
9 particularly, in a case like this, where it's so
10 subjective and so hard to quantify. Who are we to say
11 that twice the deliverability is going to impair
12 anyone? There's some doubts as to whether this well
13 is going to be as good. It's a vertical well. So the
14 speculation on correlative rights is really not what
15 we ought to be concerned about.

16 It's undisputed that prevention of waste is
17 the paramount obligation of this Commission. It's
18 been set forth in cases that have gone to the New
19 Mexico Supreme Court. That's your fundamental
20 obligation. There is absolutely no disagreement in
21 this case that a pilot project -- and we're not asking
22 for blanket rules for all highly deviated wells in the
23 Mesaverde. We're looking for a project incentive that
24 makes this economically viable so that we can do what
25 Mr. Catanach has found that we ought to be doing. And

1 that is to drill these wells to prevent waste.

2 Mr. Clayton told you his position and that
3 of his company far more eloquently than I can, but the
4 one thought that sticks in my mind from all the
5 discussion this morning is why should we be penalized
6 for the opportunity to enjoy success in this
7 reservoir? And that's all we're asking you for.
8 We're not asking you for a blank check. We've
9 proposed some limitations on how we might operate
10 this.

11 If you'll look at the transcript, I think
12 it's interesting to look at the exchange between Mr.
13 Catanach and Mr. Jones, and that demonstrates why I
14 think Mr. Catanach had the wrong focus and emphasis
15 when he wrote the very findings that Mr. Lund wants to
16 draw your attention to.

17 He presumed in his question to Mr. Lund
18 that approval of this application was going to harm
19 the offsets, and he posed the question in that
20 fashion. He presumed a question for which there was
21 only one answer: if this project harms other
22 operators in the pool. Harm, I would define as
23 impairing their correlative rights. And this
24 Commission always has retained jurisdiction of all
25 your orders. In fact, you've got the fundamental

1 obligation if subsequent evidence demonstrates to you
2 that harm is occurring with this project, you can set
3 a show cause hearing and bring us back in the next
4 day. You're not writing a check for us that we fill
5 in the amount and we're not accountable to you ever.
6 That's certainly not true. You always have the
7 ultimate power to determine what we do.

8 And what better way to judge what happens
9 with the Mesaverde than to test it with a pilot
10 project? This is the way we historically do these
11 kinds of things, and any new technology normally goes
12 through a cycle of pilot project. This particular
13 project needs an economic incentive, a special project
14 allowable.

15 And there's some logic to what we've
16 discussed for you. It's a single wellbore that
17 penetrates both halves of the spacing units, and why
18 not double the "D" for that? It sounds reasonable to
19 me. I'm not a technical person, but it just seems to
20 make sense that that should be a choice when you've
21 penetrated both halves of the 160 with this deviated
22 well, that you have the choice of taking that or the
23 other two vertical wells and calculating your
24 allowable.

25 This is a technology whose time has come,

1 and we want the opportunity, if you'll permit us, to
2 exercise the chance to see if we can't recover
3 reserves that might not otherwise be produced in this
4 reservoir. It's not unusual for this Commission to
5 encourage the development and use of additional
6 technology. We request that you not unreasonably
7 restrain yourselves as regulators and remove the
8 flexibility from us as operators in order to test this
9 project.

10 You provided that to Mr. Merrion not long
11 ago in Order R-9079. Now he's got a horizontal
12 directionally drilled pilot project. Admittedly, this
13 is an oil reservoir, and you might want to make a
14 distinction, but this Commission provides those kinds
15 of incentives. Mr. Merrion had a bonus allowable in
16 here. He had a special project allowable that was
17 higher than his depth bracket oil allowable.

18 We're not asking you for something
19 unusual. We're simply asking to make this project
20 work, to test the technology, and let us do it now
21 before we lose the opportunity to exercise this and
22 bring it back to you and show whether or not it can be
23 a success or not, and that's all we're asking.

24 CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

25 Is there anything additional in these

1 cases? If not, the Commission will take them under
2 advisement. Thank you.

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1 CERTIFICATE OF REPORTER

2
3 STATE OF NEW MEXICO)
4) ss.
5 COUNTY OF SANTA FE)

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7 Shorthand Reporter and Notary Public, HEREBY CERTIFY
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10 that I caused my notes to be transcribed under my
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13 I FURTHER CERTIFY that I am not a relative
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17 WITNESS MY HAND AND SEAL March 2, 1990.

18 
19 CARLA DIANE RODRIGUEZ
20 CSR No. 91

21 My commission expires: May 25, 1991
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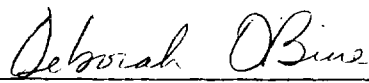
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17 WITNESS MY HAND AND SEAL March 2, 1989.

18 
19 DEBORAH O'BINE
20 CSR No. 127

21 My commission expires: August 10, 1990
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23
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