STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

APPLICATION OF CONOCO, INC.

CASE NO. 11,349

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

ORIGINAL

BEFORE: DAVID R. CATANACH, Hearing Examiner

July 27th, 1995

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner, on Thursday, July 27th, 1995, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

July 27th, 1995
Examiner Hearing
CASE NO. 11,349

* * *

E X H I B I T S

(Continued...)

E X H I B I T S (Continued)

Applicant's	Identified	Admitted
Exhibit 34	55	63
Exhibit 35	56	63
Exhibit 36	58	63
Exhibit 37	60	63
Exhibit 38	61	63
Exhibit 39	62	63
Exhibit 40	67	70
Exhibit 41	68	70
Exhibit 42	68	70
Exhibit 43	69	70
Exhibit 44	69	70
Exhibit 45	70	70
Exhibit 46	70	70
Exhibit 47	70	70

* * *

A P P E A R A N C E S

FOR THE DIVISION:

RAND L. CARROLL
Attorney at Law
Legal Counsel to the Division
2040 South Pacheco
Santa Fe, New Mexico 87505

FOR THE APPLICANT:

KELLAHIN & KELLAHIN
117 N. Guadalupe
P.O. Box 2265
Santa Fe, New Mexico 87504-2265
By: W. THOMAS KELLAHIN

* * *

WHEREUPON, the following proceedings were had at 1:20 p.m.:

EXAMINER CATANACH: Call the next case, Number 11,349, Application of Conoco, Inc., for downhole commingling and for two unorthodox gas well locations, Rio Arriba County, New Mexico.

Are there appearances in this case?

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

EXAMINER CATANACH: Will the four witnesses please stand and be sworn in at this time?

(Thereupon, the witnesses were sworn.)

MR. KELLAHIN: Mr. Examiner, Tom Scarbrough is our fist witness. He is a land expert with Conoco, resides in Midland, Texas.

TOM SCARBROUGH,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Tom Scarbrough. I'm a senior landman with Conoco in Midland, Texas.

Q. On prior occasions, Mr. Scarbrough, have you testified as an expert in matters of petroleum land management?

A. Yes, I have.

Q. Pursuant to your employment in that capacity, have you made yourself knowledgeable about the land title arrangements within what is known as the San Juan 28-7 Unit?

A. Yes, I have.

Q. And based upon that information, have you undertaken the task of tabulating the interest owners that are entitled to share in production from the Dakota and the Mesaverde reservoirs within that unit?

A. Yes, sir.

MR. KELLAHIN: We tender Mr. Scarbrough as an expert witness in matter of petroleum land management.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let's turn to the first display, if you'll unfold that. The San Juan 28 and 7 Unit is a federal exploratory unit located in Rio Arriba County, New Mexico; is that not true?

A. That is correct.

Q. When we look at Exhibit 1, what are we seeing?

A. Exhibit 1 is a map of the boundary of the 28-7

Unit. The Mesaverde participating area is shaded in red. The offset Mesaverde operators are shown surrounding the unit boundary.

Q. When we look at this display and see the symbols for wells, are we looking only at Mesaverde wells?

A. Yes, sir.

Q. All right, sir, let's set that one aside for a moment and look at the next display. Exhibit Number 2 is what?

A. Exhibit Number 2 is the same type map. It shows the San Juan 28-7 Unit boundary, and the Dakota participating area is shaded in green. The offset operators are operators of Dakota wells only.

Q. And again, when we look at the well symbols on this display, Exhibit 2, those well symbols simply represent Dakota wells?

A. That is true.

Q. As part of your work, have you caused a tabulation to be made of all the offset operators for either of the two reservoirs in terms of their identity and their current addresses?

A. Yes, I have.

Q. In addition, are you knowledgeable about the ownership within the unit as to the two reservoirs?

A. Yes, sir.

Q. Are there different participating areas within the unit for each of the two pools?

A. Yes, there are.

Q. As a result of those differences in participating areas, is it fair to conclude that there is not an identity or a common ownership in each of the spacing units for which you intend to commingle production?

A. That is true.

Q. There will be some small differences that occur because of the participating areas?

A. Well, due to the size of the participating areas, there will be differences in every ownership.

Q. All right.

A. Royalty ownership, the overriding royalty ownership and the working interest.

Q. Okay, let's look at Exhibit 3. What are we seeing on this display?

A. This is also a map of the San Juan 28-7 Unit, which shows the type of acreage contributed to the unit.

The federal land is unshaded. It's white on the map. It consists of about 28,000 acres. It covers 95 percent of the unit.

The red-shaded acreage is State of New Mexico land, which consists of about four percent of the unit.

And the purple-shaded acreage is fee land, which constitutes the remaining one percent of the unit area.

Q. Apart from the two unorthodox locations, your company is seeking to downhole commingle Mesaverde and Dakota production in three general categories, are you not?

A. Yes.

Q. You want to take some 14 existing Dakota wells and add that production in a commingled fashion with Mesaverde production?

A. That is correct.

Q. In addition, you want the authority to drill 17 new wells, initially approved as commingled Dakota/Mesaverde wells?

A. Yes, sir.

Q. And then finally, you want an administrative procedure for the balance of the undrilled spacing units within the unit, by which you can go to the Aztec OCD and get approval to produce those under an allocation formula adopted and ordered by the Division here in Santa Fe?

A. That is correct.

Q. Those are the three things you're trying to do?

A. Yes, sir.

Q. All right. Let's look at the activity you have undertaken with regards to the federal properties and the federal interests within the unit. They're apparently significant. When I look at Exhibit 3, most of this acreage is federal acreage, is it not?

A. Yes, it is.

Q. As part of your regulatory approvals, have you sought out approvals from the appropriate officer of the Bureau of Land Management to authorize you to downhole commingle all three categories of production?

A. Yes, we have.

Q. And how have you documented that for this Examiner?

A. We have Exhibit Number 4, which is a letter from the BLM, which grants approval of Conoco's proposed downhole commingling plan.

Q. All right. In addition to the BLM approval for commingling, have you sought out and obtained the approval of the Commissioner of Public Lands, State of New Mexico, for commingling as I've described it?

A. Yes, we have.

Q. And how have you documented that?

A. In Exhibit Number 5 is a letter from the Commissioner of Public Lands stating that our proposed downhole commingle procedure has been approved by their agency, contingent upon like approval by the New Mexico Oil Conservation Division and the Bureau of Land Management.

Q. All right, sir.

A. Which has already been received.

Q. Okay. In order to inform the parties entitled to notice, either the offsets or the interest owners within the unit, have you caused a summary of the Application to be prepared, and is that what I'm looking at when I see Exhibit 6?

A. Yes, it is.

Q. And was this part of the enclosures sent to all the appropriate parties entitled to notice?

A. Yes, sir.

Q. This is what they got?

A. That is correct.

Q. In addition, they got copies of some maps that help them visualize what you were trying to do in terms of where the unit was and where these wells were?

A. That is right.

Q. All right. Identify for me Exhibit 7. What is this?

A. Exhibit Number 7 is a listing of all the royalty interest owners, carried working interest owners, working interest owners, and overriding royalty interest owners, in both the Mesaverde and Dakota participating area, within the San Juan 28-7 Unit.

Q. All right, sir. And then finally Exhibit Number 8. Would you identify and describe what you have included in this exhibit package?

A. Exhibit Number 8 consists of letters that we had sent to the working interest owners in the San Juan 28-7 Unit, requesting their waiver to objection for the downhole commingle project.

Q. Give us a general idea of the working interest owners within the unit that have given you waivers or consents to do this.

A. Out of the ten waivers that we have received, their interest consists of over 95 percent of the total working interest in the San Juan 28-7 Unit.

Q. Despite the caption on Exhibit 7, does this summary of receipts also include the offset operators? You have listed the various interest owners within the unit, but does this not also include the offset operators that you've identified from an earlier exhibit?

A. Yes, it does.

Q. Okay. And then you have the waivers that you described in Exhibit 8.

Are you aware of anyone that's registered either a written or a verbal objection to Conoco with regards to this Application?

A. No, I'm not.

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

We move the introduction of his Exhibits 1 through 8.

EXAMINER CATANACH: Exhibits 1 through 8 will be admitted into evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Scarbrough, is it likely that the Dakota or Mesaverde PA's will change at all?

A. The Dakota participating area is basically fully expanded at this time. The Mesaverde participating area has not undergone an expansion since, I believe, 1975.

Q. Are any of your proposed new wells located in an area that's not in the Mesaverde PA?

A. No, sir, all of the new proposed locations are within both the Mesaverde and Dakota participating area.

Q. The list of interest owners that you notified, did that just include owners within the PAs?

A. Yes, it did. As far as the working interests, royalty interests and overriding royalty interests is concerned, yes.

Q. Are there certain interest owners that were excluded from notification?

A. No, there were not. We did notify all the offset operators as well. We notified all parties who are currently a working interest owner or receiving revenues from the Mesaverde or Dakota participating areas.

Q. That's not necessarily everybody within the unit, is it?

A. Well, there's a possibility in the Mesaverde formation that there are some lands which are undrilled that are not located within a participating area. Therefore, any owners who may own under those leases would not be entitled to revenue at this time.

Q. Exhibit Number 6, is that what you have sent to the interest owners?

A. Yes, sir, it is.

EXAMINER CATANACH: That's all I have of the witness.

MR. KELLAHIN: Call Mr. Tom Johnson.

THOMAS B. JOHNSON,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Johnson, would you please state your name and occupation?

A. Thomas B. Johnson. I'm a geological advisor with Conoco.

Q. And where do you reside, sir?

A. Midland, Texas.

Q. On prior occasions have you qualified as an expert geologist before the Division?

A. Not in New Mexico, no.

Q. Summarize for us your education.

A. I received a bachelor of science degree in geology from Winona State University in 1979.

Q. And summarize your general employment as a petroleum geologist.

A. I was employed by Conoco in 1980 as an associate geologist, working exploratory projects in the Appalachian Basin for the first two years of my employment.

I then worked for the next two years on an exploratory project that I was in charge of in southwest Oklahoma through about mid-1984.

From 1984 to 1991 I worked development geology, primarily in the west half of Oklahoma, in the Texas panhandle.

In 1991 I was assigned to work the San Juan Basin, which I work to this day.

Q. As part of your geologic duties since 1991, has it included examining the geology for areas including your company's interests within the San Juan 28 and 7 Unit?

A. Yes, it has.

Q. Conoco is currently the operator of that unit?

A. That's correct.

Q. And as operator, have you then continued to examine the geology?

A. Yes, sir.

Q. And as a result of the geology, have you worked with the engineering staff to determine the feasibility and the practicality of downhole commingling production within the unit from the Dakota and the Mesaverde reservoirs?

A. Yes, we work closely with engineering, as well as other departments such as drilling.

MR. KELLAHIN: We tender Mr. Johnson as an expert geologist.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let's start with a couple of introductory displays, Mr. Johnson. If you'll turn to your Exhibit 9 identify that display for us.

A. That is a stratigraphic chart showing the Cretaceous producing horizons in the San Juan Basin. The exhibit is modified after Molenaar.

What this exhibit shows, or was intended to show, is just the intervals that we're talking about today. In yellow -- The near-shore marine sandstones are colored yellow. Nonmarine shales, siltstones and coals are the orange color.

And in particular we're talking about he Cliffhouse, Menefee and Point Lookout members of the Mesaverde and the various members of the Dakota --

Twowells, Paguate, et cetera -- that are shown on the bottom of the stratigraphic chart.

Q. All right, let's take those two reservoirs, then, and go through the next series of geologic displays, and perhaps we can do a couple of these concurrently.

A. I think that would be appropriate.

Q. Let's look at 10 and 11 side by side. And for the record, identify what I'm looking at when I see Exhibit 10.

A. Okay, Exhibit 10 is a structure contour map that's made on the top of the Cliffhouse sandstone, the uppermost sandstone in the Mesaverde unit.

Q. Is that a commonly utilized marker point by which to map structure when we're looking for Mesaverde production?

A. Yes.

Q. All right. And then Exhibit 11 is what?

A. It's an exhibit similar to Exhibit 10. It's a structural contour map on the top of the Graneros or Base Greenhorn.

Q. All right. Now, both maps use the same criteria in terms of color coding?

A. Yes, the darker shades, the red indicates deeper depths, grading up to the lighter colors, indicates shallower depths.

You can see we have regional dip, irregular regional dip, from southwest to the northeast. Contour interval is 50 feet on both maps. And again, nothing more than irregular regional dip is exhibited. There are no extreme structural flexures, no faulting, anything that you might expect would enhance production or create any sweet spots in any way, shape or form.

Q. When the engineers have studied the reservoir and concluded it's a candidate for downhole commingling --

A. Yes.

Q. -- they've come up with three categories of well types, existing Dakota, add to Mesaverde --

A. Correct.

Q. -- some new drills, and then the option in the future for an administrative procedure for approximately 38 still-open locations?

A. That's correct.

Q. When we look at the geology, has existing development in both reservoirs continued throughout both -- all areas of the unit?

A. Yes.

Q. So you have geologic data throughout the entire unit for both reservoirs?

A. Yes, the unit's been fairly heavily drilled since the 1950s, which was when most of the Mesaverde wells were drilled.

I don't think we're going to find any surprises in here, either from a structural standpoint or a stratigraphic standpoint. There's quite a bit of well control in the unit.

Q. All right. When we look at the structural component, that is not a geologic item of importance in determining the trapping mechanism for either reservoir, is it?

A. No, this trapping mechanism in the 28-7 Unit, as in most of the San Juan Basin, is purely a stratigraphic mechanism.

Q. All right. And looking at structure in both reservoirs, if the engineers reach a conclusion in one portion of the reservoir as to commingling possibilities, you don't see any change in geology that would make those decisions different if they moved elsewhere in the unit?

A. No.

Q. All right. Let's set those aside, and let's go to Exhibit 12.

Before we talk about what this means, describe for us the identifications and the codes for the display.

A. Okay. Well, this is an outline of the 28-7 Unit, which covers all of 28 North, 7 West, and portions of 27 North 7 West, Rio Arriba County, New Mexico.

The blue dots on the map with corresponding blue number below represent Dakota wells, and the green dots with black numbers above represent Mesaverde wells.

Q. You've got two lines of cross-section shown?

A. That's correct.

Q. Which one goes where?

A. We've got two cross-sections, A'-A and B'-B, both starting from a common point in the northeast portion of the unit, and both traversing from northeast to southwest across the unit.

Q. A-A' is going to specifically look at which of the two reservoirs?

A. A-A' is a cross-section that looks specifically at the Mesaverde, and B-B' is a cross-section that looks specifically at the Dakota.

Q. Is there a reason for the orientation of this line of cross-section?

A. Yes, there is.

Q. What is it?

A. As a general statement, in fact, most of the reservoirs in the San Juan Basin are deposited in a northwest-southeast manner. Therefore, we run our cross-sections from northeast to southwest, and it shows the changes in the sandstones across the unit, the changes in development, in thickness, in the reservoir quality, as opposed to a strike section, which wouldn't show you the changes that occur from northeast to southwest across the unit.

Q. All right. Let's look at the first cross-section. Exhibit 13, then, is the Mesaverde cross-section?

A. That's correct.

Q. If we can try to characterize the productivity of the Mesaverde in the unit in terms of ultimate gas recovery out of the Mesaverde, where are we having the better wells located?

A. The better wells are located in the north and northeast part of the 28-7 Unit.

Q. And let's start there, then. Let's start at A', which is the right-hand side of the display, and have you show the Examiner where those wells are being perforated and where you're finding the productivity.

A. Okay. Well, this cross-section is hung on a marker just above the top of the Cliffhouse. It breaks out the Cliffhouse, the Menefee and the Point Lookout.

They're gamma-ray induction logs. You can see, looking at the gamma-ray, particularly for the Cliffhouse and Point Lookout, that the sands are fairly clean to the northeast. And as you move along the Cliffhouse, from the right-hand-most log, the number 218 well, moving along to the 136 and so on, you can see that the sands stay well developed by the kick of the gamma ray to the left.

This continues -- you see that -- stay in clean development until you get past the 193, when the quality of your Cliffhouse reservoir falls apart. It is very thin and almost nonexistent as you continue on to the southwest.

Same thing shows up in the Point Lookout. The sands are fairly well developed to the northeast where the Mesaverde has better productivity in the unit, and as you move to the southwest, again, reservoir quality deteriorates and production becomes poorer.

Q. Is it fair to say that the Mesaverde wells have been adequately perforated and completed in such a way that those wellbores have had the opportunity to effectively produce that reservoir?

A. Yes, they have, particularly the Cliffhouse and the Point Lookout. There may be some isolated instances in the Menefee, which are much shalier sands, although you stall may contribute a little bit to production. But the Cliffhouse and Point Lookout, there's very little potential behind pipe.

Q. In terms of reservoir continuity, if the engineers are seeing pressure depletion in various points in the reservoir, is it logically -- is it logical geologically to see an explanation for a pressure depletion in an offset well?

A. Oh, certainly, you've got -- These are fairly tight reservoirs. You've got porosities on the order of nine to ten percent in the Mesaverde. Mesaverde has qualified as a tight gas reservoir to receive Section 29 credits.

But there still is some pressure depletion in the Mesaverde. Wells, again, have been drilled and many still producing since the 1950s. The initial reservoir pressures in the Mesaverde were on the order of 1200 to 1400 pounds, and recently drilled wells show pressure in the 750 to 950 range.

So we have seen pressure depletion in the Mesaverde.

Q. Geologically, then, you don't see any reason that would preclude the Division from authorizing commingling of the Mesaverde with the Dakota?

A. No.

Q. Let's look at the Dakota now. If you'll turn to Exhibit 14, again, it has the same general orientation --

A. That's correct.

Q. -- line, and so let's start on the far right with B', have you characterize these logs, and let's move then to the southwest portion of the unit.

A. Okay, this is another stratigraphic cross-section, again B'-B, which is hung on the top of the

Greenhorn limestone.

I show a breakout of the Greenhorn, the Graneros, and then the various Dakota sands, the Twowells, Paguate, Cubero and a dashed line to indicate the top of the Burrow Canyon.

Unlike the Mesaverde, you can see that the Dakota has more of a consistent development across the unit, and correspondingly on production maps you'll see that there isn't that sharp break between good production and poor or no production.

Production -- Although there's some variability in current rates and cumulative productions, the Dakota is a little more consistently developed across the unit.

Q. Do you see any behind-the-pipe potential in the Dakota?

A. There occasionally is behind-pipe potential in the Dakota, but most of the wells in the 28-7 Unit have been perforated and productive Dakota sands.

Q. Are we likely to find, in all reasonable geologic probability, any untapped, potential high-pressure, high-rate Dakota in the unit?

A. No, sir, we don't expect any surprises. This has been a very heavily drilled unit, and the wells that have been drilled have been completed in virtually all productive intervals.

Q. Sir, let's look at Exhibit 15. Exhibit 15 deals with the Mesaverde. You have mapped cumulative gas?

A. That's correct.

Q. All right, let's set that aside for a minute, and let's get the other Mesaverde map out, which is Exhibit 16, and that's going to be the daily rate map of the Mesaverde?

A. That's correct.

Q. All right, let's look at these side by side.

The mapping, the coloring and the contouring is exclusive to either cum gas or gas rate, and there are not components or parameters based upon geologic criteria?

A. That's correct.

Q. We're just looking at volumes and rate?

A. We're looking at volumes and rates, although there's a relationship between the production that we see on both the Mesaverde cum and daily rate map --

Q. All right.

A. -- that relates to the geology.

Q. Yeah. Let me get to that point in just a second.

Now, let's start with the cum gas map, and tell us what you see.

A. The cum gas map, the darker colors indicate the higher production. The darker reds are the highest production and -- cumulative production -- and the lighter colors, going to the yellows, are the lowest cumulative productions.

You can see in the north and northeast part of the unit is where we have the best cum production, even though -- although there is some variability in the cums that we see.

Q. All right. When we take this cum map and have you analyze the geology, is there an explanation that you see as to why cum gas is higher in the north part of the unit?

A. Yes, that relates directly back to cross-section A'-A that we looked at a moment ago. Where the sands are developed in the northeast part of the unit, the production is better. As you move to the southwest where the sand quality deteriorates, the production drops dramatically.

Q. In order for the Examiner to find that he can administratively approve on a unit-wide basis commingling, he will want assurances that as you move to the south portion, you're not going to improve in reservoir quality such that he has, instead of marginal salvage operations, high production rates and cum volumes that would justify producing this as not commingled production; is he going to see that here?

A. No, I don't think we'll find any surprises in the Mesaverde. You've got Mesaverde penetrations and Dakota penetrations that don't show up on these maps. We've got a lot of control. We don't expect any surprises out here. It's a fairly well developed unit, and we feel fairly confident about where we're going to cross over from better production to poor or no production.

Q. All right. Comments and observations about the daily rate map on the Mesaverde?

A. Similarly to the cum map, you see, while there is some variability in the daily rates to the -- in the north part of the unit, that is where the best current daily rates exist. They exist for the same reasons that the cums are better in the northeast, and that is the sand development.

Average current daily rates from the Mesaverde are currently about 83 MCFD.

Q. All right. Let's look at the Dakota side of the problem. Let's look at Exhibit 17 and 18, in connection with each other.

Seventeen is the Dakota cum map, Exhibit 18 is the Dakota daily rate map?

A. That's correct.

Q. Again, give us the conclusions about the two maps and help us understand how they fit into the context of your geologic study.

A. Okay. Well, as with the Mesaverde maps, we're also color-coded with the deeper colors indicating areas of higher cumulative production and higher daily rates.

As you saw in cross-section B'-B, the Dakota is more uniformly developed across the unit, some variability, reflecting some variability in cums and current daily rates as well.

Current daily rates

MCFD for the Dakota. Average

a cumulative basis are about

So you see a more ur

and that is because of slightl

development across the unit.

Q. As we deal with the s

commingled wells and future new-drill commingled wells, do you see the opportunity here for any significant primary gas production out of the Dakota that would preclude commingling?

A. No, again we expect no surprises. You've got massive development all the way across the unit. It's fairly heavily drilled, but we don't expect to encounter anything new.

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

We move the introduction of his Exhibits 9 through 18.

EXAMINER CATANACH: Exhibits 9 through 18 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Johnson, the 14 existing Dakota wells that you intend to add the Mesaverde to, are those in one general area in the unit, or are they --

A. Yes, they're in the northeast part of the unit.

Q. Northeast part of the unit.

Are these 14 existing Dakota wells -- are they tracts that the Mesaverde has not been developed at all?

A. That's correct.

Q. There's no Mesaverde production?

A. There may be a few of them where the existing production -- Well, there's one I know of where the Mesaverde has been plugged back and recompleted to the Fruitland, so there would have been production in the past.

So we have the opportunity in that case, if sufficient reserves exist to justify the lower cost of recompletion, to come back and add the Mesaverde in cases like that.

Q. But as it stands right now, there's no Mesaverde production on these units?

A. There are some that we're looking at where the Mesaverde production has -- or was when I looked at it -- had dropped significantly. Those were possible recompletions. We may not do those if Mesaverde production in the existing wells has improved.

But for the most part, they are undeveloped in the Mesaverde.

Q. There's no instance where this will be the third Mesaverde --

A. No.

Q. -- on any of these units?

A. No.

Q. Okay. There's 17 wells you propose to drill as a new DHC. Are those also located in the northeast part of the unit?

A. Yes, sir, they are.

Q. On those units, would that be typically a second well in the Dakota?

A. It will be the 160-acre infill. There are -- Where we propose the new drills, there's currently no Dakota or Mesaverde; it's an empty quarter section, as far as those two horizons are concerned.

Q. So they're all the second well on the proration unit?

A. In the proration unit, yeah, the 160 infill.

Q. In the Dakota, not necessarily the Mesaverde?

A. Yes.

MR. KELLAHIN: Yes, what? Yes, it's a new drill in both pools?

THE WITNESS: Yes, that's correct, in both pools.

Q. (By Examiner Catanach) In addition to the 17 wells, is there additional potential for new drills in the unit?

A. Well, we're asking for the -- I believe it was 34 in the southwest part of the unit. That would be something that may be done at some point in the future, if we got much, much better gas prices and got all our costs optimized.

But those we're not looking at doing in the near future. Those -- for some time in the future -- If we're going to do them, we're going to have to do those commingled. There's no doubt about it.

Q. Did you say 34?

A. It's 38, excuse me.

Q. In the southwest part of the unit?

A. That's where they're located, yes, in the south and southwest, out of that Mesaverde, better Mesaverde productive --

Q. Those would fall under subsequent administrative approval?

A. I think we're seeking that now.

Q. Right, okay.

The -- Have you identified the 17 and the 14 well specifically?

A. Yes, we have, and the engineer will be presenting a map showing those locations.

Q. All right. You mentioned something about an average producing rate. Was that derived by -- Was that an average production rate?

A. Yes, I have an average producing rate of -- from the -- current producing rate from the Mesaverde of about 83 MCFD, and from the Dakota of about 70. And that's just the total number of wells, or completions in those, divided by the daily rates, or vice-versa.

Q. In the newly drilled wells and in the Mesaverde wells that you're going to add to the Dakota, do you expect any high producing rates?

A. No, after the initial decline -- And these wells decline hyperbolically. They come on at a fairly high rate, but then they quickly decline and level off to a constant, predictable decline rate.

We expect a range of about from 200 to 600 MCFD, stabilized production after that initial decline. We don't expect anything huge.

Q. 200 to 600 stabilized right after the initial decline?

A. Yes, and I'm speaking a little bit of engineering. And if I misspeak, our engineer can clarify.

Q. Is that in both the zones?
A. Yes.
Q. In the southwest part of the unit, would you expect that range to go down considerably?
A. Oh, yes. Yes, that would. The Dakota may not change much, but the Mesaverde, yeah, we don't expect those kinds of rates down there. Or certainly it would be at the low end of that range at best.
Q. The main produced intervals in the Mesaverde in this unit are the Cliffhouse and Point Lookout?
A. That's correct.
Q. Menefee is not much --
A. We will -- If there's some clean and developed Menefee -- and even the clean Menefee is not as clean as the clean Point Lookout and clean Cliffhouse. It's shalier, more of a siltstone.
But if it shows a clean-up and it shows some resistivity and we have indications of gas shows and some favorable log characteristics, we will attempt to add it to the flow stream.
EXAMINER CATANACH: That's all I have of the witness.
MR. KELLAHIN: Our next witness is Matt Stanley.
Mr. Stanley is the reservoir engineer on the project.

MATTHEW L. STANLEY,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Stanley, would you please state your name and occupation?

A. Yes, sir. Matthew Lee Stanley. I'm a senior reservoir engineer with Conoco, Incorporated, in Midland, Texas.

Q. And you reside in Midland?

A. Yes, sir.

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

A. No, I have not.

Q. When and where did you obtain your degree in engineering?

A. I graduated from New Mexico Institute of Mining and Technology in Socorro, in May of 1984 with a bachelor of science in petroleum engineering.

Q. You and Mr. Catanach were not there at the same time, were you?

EXAMINER CATANACH: Not quite.

Q. (By Mr. Kellahin) No hard feeling between you, nothing personal. Here we need to disclose --

A. He's probably not a Socorro native either.
Q. Describe for us your function here with regards to what you've done in this project. I assume that you were the project engineer that took the lead in doing the engineering work to determine whether commingling was appropriate.
A. Yes, sir, one of my primary responsibilities when I moved down to Midland Division in 1992 was to study the infill drilling and development potential of the unit.
Q. How long have you been working on that project, Mr. Stanley?
A. The main project was completed in 1993, and we became the operator of the 28-7 Unit in March of this year, hence were here before the Commission to try to optimize the development, that we saw potential existed in the unit.
Q. The Application that you're presenting to Mr. Catanach, is this the same information and request that you have provided to the Bureau of Land Management?
A. Yes, it is.
Q. And is this the same concept and request that you applied for and received approval from the Commissioner of Public Lands?
A. Yes, it is.
Q. And based upon your study, do you have conclusions and opinions that support approval of this

Application?

A. Yes, I do.

MR. KELLAHIN: We tender Mr. Stanley as an expert reservoir engineer.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let's take a moment and have you summarize for us your major engineering conclusions, and then we'll look at the reasons that support those conclusions.

A. Sure. One of the things that's evident, probably evident from the geologist's maps, is that this is a fairly marginal unit. We're talking about production from the 1950s, and the average cums of 1.3 to 1.4 BCF in the Mesaverde and lower in the Dakota.

So it's obvious that this is fairly marginal production, yet there are a number of locations where we know hydrocarbons exist in the ground in the Mesaverde and Dakota, and we would like to somehow develop those.

In the course of studying the unit, we basically proved that the only way to further development of the hydrocarbons in the unit is to downhole commingle. What this allows us to do is to reduce the drilling costs, development costs, in the unit.

The other thing it allows us to do over the dual situation is to improve the recovery from both zones. We have a liquid-loading problem in the unit, and we need to address that. We're trying to address that through the downhole commingling.

And I think we'll show in the exhibits here that the potential loss of reserves, when you compare a dual versus a commingle, amounts to several million dollars' worth of reserves.

And that's another main reason for trying to commingle in the unit.

I'll try to address the three categories, if you will, of commingles that we're seeking to have approval for, and also any potential problems with Rule 303 that might exist.

Q. As a result of your work, are you able to make a recommendation to the Examiner on an allocation formula to apply?

A. Yes, sir, I am. I've done some extensive modeling work in the area, and I'll use that to show you how we propose to allocate fairly the reserves from the two zones when they're commingled.

Q. Let's go through your study. Let's start with Exhibit 19. Perhaps that's a good one to look at. And then we'll hold it available because I think it's a pretty good reference map.

A. Yeah, I think some questions were being asked about this --

Q. All right, sir, let's talk about this one for a moment, then. Help us understand your locator.

A. Okay. Again, you see the outline of 28-7 Unit on here and the Dakota participating area. That was simply the map we chose to put all these symbols on.

The blue dots are the 17 staked locations that we have out in the unit.

The green circles represent the wells that we were looking at for possible recompletion commingles with the Mesaverde formation.

And the red dots are the potential future commingle locations, Mesaverde-Dakota, in the unit.

Q. All right, sir. Let's hold that aside and then look at some of the other tabulation of data.

First of all, identify for the record what Exhibit 20 is.

A. Exhibit 20 is simply a list of the staked locations that we currently have in the unit.

Q. All right. These are the 17 new drills?

A. Yes, sir.

Q. All right. After that, Exhibit 21 is what?

A. These are the additional undrilled Mesaverde quarter sections, the 38 wells.

Q. In each instance, then, this would be the infill or the second well for both pools? Do we have some exceptions?

A. There's some exceptions in the Mesaverde where the PA has not been expanded, and there may be shut-in wells. So there's not a currently producing well in those --

Q. All right, I didn't ask you this right.

A. I'm sorry.

Q. When I'm looking at a 320 in the Dakota and a 320 in the Mesaverde, are all these open 160s --

A. Yes, sir, they are.

Q. -- that are common to both pools?

A. Yes, sir, they are.

Q. All right. Exhibit 22, what's this?

A. Exhibit 22 is a list of the wells that we're looking at for possible recompletion commingles. They're existing Dakota wells, and we'd be looking at adding the Mesaverde pay in the well as a commingle with the existing Dakota production.

Q. As we look at the proposed 14 existing Dakota wells to add the Mesaverde to, do you as a reservoir engineer see any material difference in any of these wells to cause you to exclude any of those wells as candidates for commingling?

A. No, sir, I don't. In fact, the wellbore configuration in these wells emphasizes the need for us to commingle. We cannot dual these locations because of the size of the casing.

Q. Okay. When we look at the new drilled 17 locations as they are distributed in the reservoir, as a result of your work do you see any material difference as we move among those 17 locations to exclude any of them?

A. No, I don't, I sure don't.

Q. And is your engineering work consistent with the geologic conclusions that were expressed concerning the fact that as we move to the south in the reservoir, we're moving to less reservoir quality, and therefore less productivity in both reservoirs?

A. I see the same thing on the type-curve work and the modeling that I've done.

Q. All right. Let's talk of the next topic, which is the next few displays. It is to have you quantify and illustrate this liquid-loading problem issue.

Give us a quick summary of what's the problem and how are we going to fix it.

A. Okay. Basically, these are gas wells which produce minor amounts of condensate and water.

What happens, though, as the reservoir pressure and wellbore pressure declines and the rate declines, is that these liquids can no longer be flowed up the tubing.

So what happens, the liquids eventually build up downhole and hurt our production. It causes the production to drop below what would be considered a normal production rate, because we're increasing the bottomhole pressure, we're increasing the liquid saturation near the wellbore and potentially introducing a scale problem.

So we see the hydrocarbon production dropping off as the liquids load up in the wellbores.

Q. Now, is that characteristic of what we're seeing with existing Dakota wells, or is it true of the Mesaverde as well?

A. It's true of both zones.

Q. All right. Let's take an example. If we've got a well that's currently a single Dakota, it's plunger-lifted, you've exhausted your efficiency on that well and you still have a liquid-loading problem. By adding the Mesaverde to those wells, what do you achieve?

A. What we achieve by adding the Mesaverde to those wells is additional gas influx into the wellbore to allow for the expansion that's required to lift the plunger to the surface.

So what it's going to allow us to do is to get the Dakota production back on its normal trend, because we're able to lift the liquids off the Dakota.

Q. All right. You've identified the issue. Now, let's try to quantify it. If you look at Exhibit 23, can you give us a range of the problem?

A. Yes, sir. Exhibit 23 is a compilation of 27 wells that have plunger lift in the unit. And you can see from September of 1994 through February of 1995, we've had a significant drop in production from these wells.

What happened in this time period is, operatorship shifted to Conoco, and there was the necessary removal of some of the equipment that controlled the plungers that were traveling to remove the liquids from the wellbores.

When this equipment was removed, the liquids could no longer produce to surface, and we had a loading problem, and you see the subsequent drop in production rate.

And this is a combination of Mesaverde and Dakota wells, the 27 wells that we knew that existed in the unit that had plunger lift.

And again, for both zones we see significant drop in production due to the liquid-loading problem.

Q. What are the numbers?

A. Okay, the numbers -- We see a drop from 2.4 million a day, roughly, to about a million a day. So a very severe drop in production during that time period, when the plungers weren't operating efficiently.

Q. All right. Let's give the Examiner two examples, one from the Dakota and one from the Mesaverde, where we can see typically the performance of each category of well that exhibits this problem. Let's look at 24 and 25 together.

A. Okay.

Q. 24 is what?

A. 24 is an example from a Dakota well. It's the Number 134E. It's up in the northeast portion of the unit.

Q. 25 is what?

A. And 25 is a Mesaverde well, Number 44. It's also up in the northeast portion of the unit.

And on both of these I'm going to try to show the potential reserve loss if we weren't able to plunger-lift these wells.

Q. All right, show us.

A. Okay, 134E, to the best of my knowledge, plunger lift was installed in 1989. Prior to then, the well had to be blown down continually to try to lift liquids from the wells.

Basically, a well gets blown to atmosphere during this time. There's a loss of lots of hydrocarbons to the air. And you can see that the well just did not produce very often. It was shut in for lengthy periods there.

After the plunger lift was installed, you can see a much more uniform production history, much like what you would expect from a typical gas well.

And I calculated a minimum reserve increase for installing plunger lift on this well of about 250 million cubic feet. And there's an associated liquid hydrocarbon increase as well. It's relatively minor.

Q. Are these characteristic of both categories of wells throughout the unit?

A. Yes, sir, they are.

Q. So when we look at Dakota wells in other portions of the unit, they are going to exhibit a liquid-loading problem that can be minimized by downhole commingling?

A. That's correct.

Q. And the same is true of the Mesaverde?

A. That's correct.

Q. So not only are the existing Dakota wells candidates to commingle to solve the liquid problem, the new drills are going to have the same problem that you can avoid by initially drilling them as commingled wells?

A. That's correct. In fact, in some of the most recently drilled wells we've already seen some liquid-loading problems. In fact, one well dropped to zero MCF per day recently in the Mesaverde because of the liquid-loading problem.

And because of the casing and tubing design in that well, we're having a very difficult time removing the liquids from the Mesaverde side.

And I want to point out that it's also the time in the wellbore's life that they're seeing the highest pressure they'll ever see. So I want to emphasize that these are the highest pressures these wells will ever see, and we're still having a liquid-loading problem and the associated loss of reserves.

Q. Let's turn to Exhibit 26 and have you identify and describe that display.

A. Okay, Exhibit 26 is a very simplified force calculation on a plunger-lift operation. Basically, it's just P1/V1 equals P2/V2, if you will, from when the plunger is at the bottom of the hole to when it's at the surface.

If you look carefully, there's a solid line traveling diagonally through the graph. That's just where force upward equals force downward when the plunger is at the surface.

Now, I did not put any liquid load on here. I did not put any slippage or friction, so it's very simplified.

And for the red and blue case that you see on here, those are the typical dual configurations that you would see out in San Juan Basin. And you can see that for the simplified case they're both near the upward force equals downward force, or below that point.

When we go to the commingled case, which is with 4-1/2-inch casing, we can see that it's always above the line. That's why we're able to lift the liquids in the case of a commingled well and not able to do it with dual completion.

Q. You described that you had taken reservoir data and constructed a computer-assisted model?

A. Yes, sir.

Q. What was the purpose to do that?

A. The purpose to do that was, we knew there was some depletion in the reservoir through time. We wanted to confirm to ourselves that there were still reserves to be had in the infill location, so that was one of the purposes.

The other purposes that kind of grew from there was to see, well, once we knew we needed commingling, you develop this unit, is there a fair way to allocate production? And what would the commingling do for us in terms of the potential crossflow or other problems that might exist?

Q. As part of the modeling effort, then, you were able to determine there were additional recoverable gas reserves that could be achieved in the unit most efficiently by commingling?

A. Yes, sir.

Q. And that you figured out downhole commingling was the only practical option by which to increase that production?

A. Particularly in light of the liquid loading. I cannot simulate that easily when I run a model, so everything you're going to see coming up in my models does not include liquid loading. I just want to get that out.

But all the -- Even with that aside, all the modeling work indicated we needed to commingle in order to efficiently develop the reserves here.

Q. Well, the model, then, would give you your best-case --

A. Best case.

Q. -- most optimistic results, and we know real world would be worse?

A. Yes, sir.

Q. All right. And then finally you can use the model to help you come up with an allocation formula?

A. That's correct.

Q. All right. Let's look at the input data, if you will, on Exhibit 27, by which you set up your model.

A. Okay, because of the lack of pressure-transient data in the unit, I needed some method to determine rough permeabilities, skins, drainage areas, and so forth, to try to get an idea of what the typical well's parameters are, the reservoir parameters, drainage area and so forth.

What I utilized was a series of Fetkovitch type curves in which you plot production versus time on a log-log scale and fit that to type curves in a transient low period and depletion period for the well.

From that fit of the data points, you can calculate your skin for your well, permeability, assuming you know a thickness. And entering a porosity number, then, you can enter -- you can calculate an area of drainage, as well as a potential recovery factor for that area and ultimate recovery from the well.

Q. All right. You get your model set up, and then you're going to have to validate it by calibrating it to actual data of some kind?

A. That's correct. I used --

Q. What did you calibrate against?

A. Okay, I calibrated to a series of Fetkovitch type curves for all the Dakota wells and all the Mesaverde wells in the unit, at least all that had curves that were normal. Wells that were shut in for long periods of time, I could not fit, obviously. But wells that had smooth curves, I could look at all those. And it was over 50 wells in the Dakota and the Mesaverde that I was able to derive this type of information from.

Q. Once you calibrate your model and start putting in all these reservoir values for which you have confidence and then you'll run your model and try to match gas-production histories; is that what you did?

A. In this case, all I did was take the average values to see -- Well, does that represent the infill wells that we saw in the Eighties?

Q. All right, let's do that. Do you have an example of how you did that?

A. Yes, sir.

Q. Exhibit 28?

A. Exhibit 28 is a plot showing the average production for the 1980s infill Dakota wells, along with simulations for the unit based on the data that I've just described.

Q. Why did you use the 1980 infill wells?

A. The 1980 infill wells represent a period later in the life of the reservoir, where there's been some pressure depletion, and we know we're even farther down the line now.

I wanted to get an idea on calibrating this model that we're matching the pressure history, as well as the rate decline through time has been depleted somewhat, the pressure in the area.

Q. All right. Are you satisfied with the match?

A. Yes, I am. I think all the points basically follow within reason, with the real numbers here.

Q. All right. When we move over to Exhibit 29, then, what do we see?

A. Exhibit 29, rather than taking an average for all the 1980s wells, I pulled three wells at random from the northeast portion of the unit and plotted those with what I call Dakota base model run. And you can see that those curves fall right in line with what the model is predicting.

Q. Did you also try to validate your model by looking at pressure information?

A. Yes, sir.

Q. And how did you do that?

A. On the next plot, if you'll turn to Exhibit 30, you see the decline in Dakota pressure through time, based on shut-in pressures at the surface that the states required the operators to gather.

And the red blocks in there are the model numbers, and the blue triangles are the actual data from the field. And again, I think the match is very good.

Q. All right. We're talking about the Dakota and how you've calibrated and validated and matched Dakota parameters. What did you do on the Mesaverde?

A. Mesaverde was very similar, constructed a model, and input the 1980s infill wells onto this graph along with the various model runs. And again, the curves basically overlie each other.

Q. Okay, now that you've got your model set up where you're satisfied as an engineer that it's accurate, reliable and can make forecasts upon which you can spend money and do things, did you make some forecasts?

A. Yes, sir, I did.

Q. And what's shown on Exhibit 32?

A. On Exhibit 32, what I'm looking at is -- I'm making a series of model runs, and what I'm varying is the permeability and pressure that we might see in the new infill locations, the 17 wells that we have proposed, as well as possible future locations.

And what you see on this plot, the blue blocks represent both Dakota and Mesaverde cum production at the end of ten years. And the green diamonds, if you will, represent the rate at the end of that ten-year period for those various model runs.

Q. On the left side of the display, then, the rates for Mesaverde, I don't see any point in here where you're going to be above 200 MCF a day.

A. No, sir. Again, it's very typical of the unit, the averages that we're seeing now, 70 to 80 MCF per day, these wells, because they want them produced as long at ten years. But they're dropping down in that range as well.

Q. And the best you can see on the gas recovery, the cum for Dakota is just shy of 700,000. And then on the Mesaverde side, the best forecast is up somewhere under 900,000?

A. That's correct.

Q. All right. You're going to use that information, then, later when you look at your cost components and try to figure out which is the most efficient way to do this and whether you can afford to do it any other way?

A. Yes. We use these cases to develop our economic models to determine, can we access these potential reserves in the unit? And what's the best way, if we can?

Q. One of the issues that we commonly talk about is whether you can make informed decisions on commingling based upon an initial rate, and I think the geologist described that in the first two to three months we have a rate that suddenly falls drastically on decline?

A. Yes, sir.

Q. How did you address finding out what happens and whether what you saw happen is typical of both reservoirs in the unit?

A. Okay, again, if you look back at the previous plots, the match of the model production and the actual infill location is very good.

I also compared the 1994 infill wells with the models to see, are they still valid? Because I was comparing 1990s data. Now I have 1994 data -- Or 1980s data.

Now I have 1994 data. Do the models still reflect what we're seeing when we're infill drilling in the unit?

Q. All right.

A. And Exhibit 33 shows that.

Q. All right. Show us the conclusions off of Exhibit 33.

A. Okay. I'd like first to concentrate on the two upper lines.

The star represents two base-case totals, the Mesaverde and Dakota commingle case. That's the total production we see at the end of three months and the end of six months.

What we see in the kind of magenta -- whatever color that is -- blocks is the actual 1994 total at the end of three and six months.

Now, those are dual wells. All I'm doing is adding the Mesaverde and Dakota production to get those numbers.

So those are the average rates for the 1994 infill wells, compared to the base-case model runs. And again, there's a very good comparison.

Q. All right, let's turn to the issue of costs. If you'll look at Exhibit 34, you're summarized for us the historical and projected costs --

A. Yes, sir.

Q. -- for the different kinds of wells that might be drilled.

A. Okay.

Q. Summarize that for us.

A. First, in the upper box, I have some historical numbers. Highlighted in red are the 1994 average from the 28-7 Unit. The average cost for the duals was $785,000.

Conoco's benchmark for a dual that we drilled last year was $724,000, so basically in the same range. And there's a couple of them that Meridian oil -- they dual wells for about $740,000. The AFEs that come into Conoco are for about that amount.

What we did when it became apparent that we were going to take over the unit was, we got a team of drilling engineers, production engineers and reservoir engineers and geoscientists together to see how can we possibly reduce the costs in this unit so that we can develop these infill locations.

And you see in the lower box here what we've come up with for protected costs if we are able to put together a drilling program so we get some economies of scale, and if we're able to commingle. You see the cost drops from last year's $785,000 to $545,000.

Q. Help me understand this economy of scale. The project is a project where you will have authority, within certain guidelines and decisions by the Examiner, to go ahead, plan for, budget, buy materials, equipment for a comprehensive plan for commingling?

A. That's correct. If we're able to commingle, then we'll be able to buy our casing in large quantities, our tubing, our separators, and all of that we'll realize an economy of scale by ordering in large volumes.

Q. Rather than doing these one at a time?

A. That's correct.

The other economy of scale, is in talking with the various drilling contractors, our drilling engineers have revealed to us that the lowest cost that we'll be able to get is if we're able to put a drilling package together, such as the 17 wells that we've staked.

Q. All right, let's look at the economics now to understand why you've concluded that it's -- the only practical means to do this is with commingled production.

A. Okay. If you'll look at Exhibit 35, these are just some generic economics for those base model cases. Again, those are optimistic, because there's no liquid loading in there.

If you'll look at the blue triangles up at the top, that's for the Mesaverde and the Dakota base cases combined in a commingle. So those are the flow streams for the commingle case.

And what you see on the X axis is various development costs. And I've highlighted on there the cost for the 1994 duals and the projected commingle cost if we're able to realize these economies of scale.

And you can see that based on $1.18/MCF gas price, even last year's projects are pretty marginal, below 15-percent rate of return. Our actual gas price out in the unit right now is below 90 cents.

Q. If I'm reading the horizontal scale, I'm going to pick a point, I guess, halfway between the $500,000 and the $600,000, which is your projected commingling cost, the $545,000?

A. Yes, sir.

Q. I'm going to read vertically, and I'm going to find that on the commingled case we can just barely break 20 percent --

A. That's correct.

Q. -- initial rate of return.

A. And I might add that that's not our risk case. We've obviously tried to develop the best locations already in the unit. We're coming down to the worse and worse locations. So when we look at a risk case, it's even worse than that.

Q. All right. And this doesn't include the liquid loading-issue that increases the risk?

A. That's correct.

Q. So your best case in the better part of the reservoir shows a 20-percent rate of return?

A. That's correct.

Q. It doesn't let you do it any other way, does it?

A. There's really no other way to develop these locations. And currently Conoco's hurdle for tight gas -- We typically look for profitability index of about 2. That would be about a 26-percent rate of return on these flow streams.

Q. All right, let's look at another way to approach that issue. If you'll identify and describe 36, Mr. Stanley --

A. Okay.

Q. -- Let's talk about that.

A. What I wanted to show here is a worse case -- some of the worse locations that we're getting into, lower permeabilities, lower pressures -- and combine those two worst. Now, it's not the worst cases that we saw in the previous graphs, but it's a little worse than the base cases.

And you can see the effect that that has on the rate of return. The combined-case rate of return for our commingled costs is now down around 15 percent at best. And again, that's not for current gas prices.

Q. You said earlier that you had examined all the issues under Rule 303 in terms of the regulatory limitations on commingling, and you found that you could satisfy all of those?

A. Yes, sir.

Q. When we look at those technical issues, is there any problem with regards to the compatibility of fluids or gases?

A. No, sir, the gases -- the BTU content is essentially the same, the Mesaverde and Dakota. The water analyses that we've seen from the unit are basically the same, and there's no compatibility problem there.

Q. Commingling the production is not going to result in reduced value for the product?

A. No, it won't.

Q. Any kind of pressure-differential issue that should be of concern in terms of crossflow?

A. Okay, in terms of crossflow there's not a concern.

If you read the rule, the reservoir pressures do exceed the limit. The Dakota reservoir pressure is between 1700 and 2500. At least that's our estimate. And the Mesaverde is between 750 and 950.

But during the time of production, there will be no crossflow, because the producing pressure is much lower than the reservoir pressure.

And because these wells are tight, even during a shut-in period, we don't see anywhere close to reservoir pressure in the bottom of the hole. In fact, if you look at the state seven-day tests, there's only a 45-percent difference on average between the Dakota and Mesaverde on that seven-day test.

Q. Do you have a recommendation on how to establish a method for allocating production?

A. Yes, I do, and it's based on these model runs, which we've shown are realistic, and the next exhibits address that.

Q. All right, let's talk about that.

A. Okay, this next -- I know it's a little busy. This Exhibit 37, what I've done here is take a Dakota case and compared that to six Mesaverde runs, where I varied the pressure and/or permeability.

And what I've plotted here is the percent of production from the Mesaverde formation through time. You see some early variability because the Dakota pressure is higher than the Mesaverde. But as the wells decline hyperbolically, the percent of production from the Mesaverde becomes almost constant. And this extends on throughout the life of the well.

So based on what we see on this plot here, we can test the Dakota zone for three months, test the Mesaverde zone for three months, and then allocate production fairly, based on those three-month tests.

Q. And you could do it on a one-time test?

A. Yes, sir.

Q. We wouldn't have to readjust and reallocate over the life of the well?

A. That's correct.

Q. Okay. Is that what you propose to do?

A. Yes, it is, for the 17 new wells, that's correct.

Q. All right. What do we do for the existing Dakota wells to which we add the Mesaverde?

A. For the existing wells, what we do is take the base Dakota decline and project that out into the future and assign the incremental production to the Mesaverde formation.

Q. Okay. All right, sir, and then we get to the last display, I think, is Exhibit 39.

A. Okay, yeah, 38 is just a comparison. We didn't really talk about it. It's one Mesaverde case versus a series of Dakota cases, so you can see it doesn't matter which reservoir you're sensitizing, the results are the same.

Q. And that's the conclusion and the point of that display?

A. Yes, sir.

Q. All right, 39 then?

A. Thirty-nine is a plot to show what would happen if a well were shut in for a lengthy period of time. Would we have some crossflow?

And if you look at the kind of greenish-colored diamonds at the end of the plot, that shows the production from the Dakota that could possibly enter the Mesaverde formation during an extensive shut-in period.

We don't anticipate that we would ever have this occur out in the unit. If we did, we would address it by setting a bridge plug or somehow addressing the crossflow.

But this potential problem, although it's very minor, really pales in comparison to the loss of reserves that we'll see if we're not allowed to commingle.

Q. Were Exhibits 19 through 39 prepared by you or compiled under your direction and supervision?

A. Yes, sir, they were.

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

We move the introduction of his Exhibits 19 through 39.

EXAMINER CATANACH: Exhibits 19 through 39 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Stanley, on your 17 new drills, how would you -- Would you complete one zone and test it?

A. The proposal is to complete the lower zone, which is the Dakota, first, test it for that three-month period, flowing down the sales line --

Q. Uh-huh.

A. -- and then come uphole -- Set a bridge plug, come uphole, complete the Mesaverde section, test it for three months, use the rates at the end of those periods, then, to allocate production when we finally pull the bridge plug and commingle.

Q. Has the BLM agreed to this procedure for allocation?

A. Yes, sir, they have. In fact, if their engineer told us that he's seen the same thing farther south in the Basin on some of the work that he's done.

Q. Fourteen existing wells, we're just going to take your Dakota decline and project that to give you some daily rates or monthly rates or --

A. What we'd probably do is have an average for a year, so that then we can account for it much easier.

Q. Anything over that would be attributed to the Mesaverde?

A. Yes, sir.

Q. You've essentially determined that dual completions are not going to be economic in this type of situation?

A. No, if you look at the ideal, best cases, the rates of return still aren't fantastic.

And when you consider the liquid-loading on top of that, knowing that those were the ideal cases, it's really -- When you look at a risk case, it's not viable.

Q. Now, your ideal situation represents -- What kind of situation are we talking about?

A. When I run a simulation, I can't have any liquid-loading in the wellbore, at least not easily. So it's just a gas well flowing with no liquid-loading, no scaling, no induced saturation near the wellbore because there's a liquid saturation in the wellbore, or a liquid level in the wellbore.

So you're looking at a lot of idealized cases here, and the model runs just don't reflect reality in terms of constant production at those rates.

Q. Now, you did this for various rates of production?

A. What you see on the different models are -- Which exhibit are you referring to? I'm sorry.

Q. Well, I'm looking at 36, 35.

A. Okay. If you look at Exhibit 36, that's Dakota model Case A and Mesaverde model Case 4A, which -- There's a variation in pressures, I believe, for those two cases, from the base case, which is the previous exhibit. And the blue triangles represent the rate of return that we would see for various costs for those two cases, combined as a commingle.

If you refer to -- What exhibit is it? Exhibit 32, that will give you an idea of how the cumulate recovery varied on those model runs at the end of ten years.

So you have Case 4A on the Mesaverde side and Case A on the Dakota side there.

Q. Okay. On the new drills, you're not going to install any plunger-lift-type situation?

A. Initially, I think there will be enough gas flow to where we won't. But we will set up the tubing string in the casinghead to where we can, and that would probably be a year or two down the road.

Q. Is there any -- Is there appreciable condensate produced from either of these zones, and is that going to be a problem for allocation?

A. No, it's not. The average cum to date in the Dakota is about 6900 barrels, and for the Mesaverde it's 7500. So they're very comparable, similar gravities.

EXAMINER CATANACH: That's all I have of the witness at this time, Mr. Kellahin.

MR. KELLAHIN: We need to take about five minutes and put the topographic exceptions for these locations into the record, Mr. Examiner.

To do so, I'd like to call Mr. Hoover.

JERRY W. HOOVER,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. I'm Jerry Hoover. I'm a petroleum engineer. My current title is Senior Conservation Coordinator with Conoco.

Q. And where do you reside?

A. Midland, Texas.

Q. On prior occasions have you qualified as an expert petroleum engineer?

A. Yes, I have.

Q. As part of your current duties, are you ultimately responsible for assisting your company with regulatory approvals for locations?

A. That's correct.

Q. On occasion you've run across locations that don't meet the standard location dimensions of the various pool rules, don't you?

A. Yes.

Q. Have you found some in this case?

A. Yes, we have.

Q. Let's look to see what they are.

A. All right. If you'll look at the first exhibit in this packet, titled Number 40, it's a section of a topographic map along the eastern side of the 28-7 Unit.

In the red circles we show most of the new drills. This area doesn't cover quite all of them. I think there are 14 here.

This is just to give you an idea of the tremendous problems we have in locating wells in this area. You can see the tremendous relief in the terrain in this area. There are dropoffs of up to 1000 feet off these mesas, down into the valleys. So I think it was remarkable that there were only two wells out of this entire program that we could not stake at standard locations.

Q. Find those two wells for us.

A. You will see those on Exhibit 40 at the bottom right-hand corner with the black arrows, Number 125M and Number 157M.

Q. In what particular or generalized way are they unorthodox locations?

A. They are not the required setback from the edge of the spacing unit.

Q. Okay. What else have you shown?

A. Turning to Exhibit 41, which is stapled with 42 and 43, all deals with Well Number 125M.

We've shown first in 41 the C-102, showing the location that it's staked at. You'll note that the 1140 feet from the west line certainly meets the standard for the pool. We're shy 210 feet on our location from the northern boundary.

Q. You're supposed to be 790, aren't you, from the -- both --

A. That's correct.

Q. -- from the boundaries of both pools?

A. That's correct.

Q. What's the next display?

A. 42 is, again, a topographic plat. I've outlined for you in red the section in which this well is located to give you a little perspective.

You can see from the contours on the topographic map, around the spotted well, how tremendous the relief is.

This well is actually located down in the Gomez Canyon, and we tried to move far enough south from that section line in order to get it the prescribed 790 feet from the line, and that's just as far up that canyon as we could move the location and still stake it.

Q. Exhibit 43, what does that show?

A. Forty-three is a site plan showing the proposed drilling location. I've underlined in red all those things which were restrictions to us, mesa slopes, a deep arroyo on one side, a sandstone ridge and an arch site on the other. We were able to squeeze the location in there to the BLM's requirements.

Q. Is there any other location within this 160 acres that would be standard and yet meets all the topographic and surface limitation requirements?

A. There was not.

Q. All right, sir, let's turn to the next one, which is the Well Number 157M, and --

A. That's correct.

Q. -- and identify for us Exhibit 44.

A. All right, Exhibit 44, down in Unit P of the section, you can see, meets the requirement from the south boundary. It is the prescribed 790 feet.

We were 78 feet short from the east line of meeting the required 790 feet.

Q. All right, Exhibit 45.

A. 45, if you'll look at the topographic map, you can see again the tremendous relief in the southeast quarter of that highlighted section. The Gomez Canyon again comes across that quarter section, which was one of our problems. There were also a number of arch sites which we'll see on the following exhibit, Number 46.

Q. And then finally Exhibit 47?

A. Yeah, 46, you can see it's surrounded by identified arch sites.

Forty-seven, then, is the complete site plan, showing everything, showing the archeological sites, showing an existing well that's already there. It shows the proposed fencing that we negotiated with the BLM in order to protect these arch sites.

Literally, this exact location is the only spot the BLM would approve in this quarter section. We could not push it one foot further to the west.

MR. KELLAHIN: Thank you, Mr. Hoover.

Mr. Examiner, we move the introduction of Mr. Hoover's Exhibits 40 through 47.

EXAMINER CATANACH: Exhibits 40 through 47 will be admitted as evidence.

MR. KELLAHIN: That concludes our presentation.

EXAMINER CATANACH: I have no questions of this witness. He may be excused.

Is there anything further, Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER CATANACH: There being nothing further, Case 11,349 will be taken under advisement.

(Thereupon, these proceedings were concluded at 2:48 p.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11349, heard by me on July 27 1995.

David R. Catanach, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL August 4th, 1995.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998