STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

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

APPLICATION OF MERIDIAN OIL, INC.

CASE NO. 11,274

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

ORIGINAL

BEFORE: WILLIAM J. LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
GARY CARLSON, COMMISSIONER

April 27th, 1995

Santa Fe, New Mexico

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

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I N D E X

April 27th, 1995
Commission Hearing
CASE NO. 11,274

(Continued...)

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E X H I B I T S

Meridian	Identified	Admitted
Exhibit 1	10	60
Exhibit 2	15	60
Exhibit 3	18	60
Exhibit 4	54	60
Exhibit 5	20	60
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Baker Hughes INTEQ Brochures:		
Drilling Systems	26	-
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Oil Conservation Division		
Exhibit 1	92	102

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* * *

A P P E A R A N C E S (Continued)

ALSO PRESENT:

BILL HAWKINS
Amoco Production Company

LARRY SANDERS
Phillips Petroleum, Odessa, Texas
Representing Permian Basin Petroleum Association

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WHEREUPON, the following proceedings were had at 9:15 a.m.:

CHAIRMAN LEMAY: Call Case Number 11,274, which is the Application of Meridian Oil for statewide administrative approval for high-angle/horizontal directional wells drilled in New Mexico.

Appearances in Case 11,274?

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing today on behalf of the Applicant, Meridian Oil, Inc.

I have two witnesses to be sworn.

CHAIRMAN LEMAY: Thank you.

Additional appearances?

MR. HAWKINS: Commissioner, I'm Bill Hawkins with Amoco, and we don't have any legal representation today, but we would like to make some comments and suggestions on the rules.

CHAIRMAN LEMAY: Thank you, Mr. Hawkins.

MR. CAMPBELL: Mr. Chairman, Dow Campbell, attorney with Marathon Oil Company, and -- out of Midland, Texas, and we have one witness.

CHAIRMAN LEMAY: One witness?

MR. CAMPBELL: One witness.

CHAIRMAN LEMAY: Thank you.

MR. KENDRICK: Ned Kendrick with Montgomery and

Andrews law firm for Mobil Exploration and Production, Inc.

No witnesses, just a couple of comments.

CHAIRMAN LEMAY: Thank you.

MR. SANDERS: Larry Sanders with Phillips Petroleum out of Odessa, Texas, representing Permian Basin Petroleum Association.

And we have just a prepared statement that I'll read in.

CHAIRMAN LEMAY: Thank you, Larry.

MR. CARROLL: Mr. Chairman, Rand Carroll on behalf of the New Mexico Oil Conservation Division.

I may have one witness that I'd ask you to swear in.

CHAIRMAN LEMAY: Okay, anyone else?

Those witnesses that are going to be giving testimony in the case, will you please stand and raise your right hand?

(Thereupon, the witnesses were sworn.)

CHAIRMAN LEMAY: Thank you. You may be seated.

Mr. Kellahin, you may begin.

MR. KELLAHIN: Thank you, Mr. Chairman.

(To audience) There's more of these handouts up here if you'd like to have copies.

Mr. Chairman, Meridian appreciates the opportunity to present a discussion for you this morning concerning the adoption of some administrative procedures for horizontal wells.

The two experts I'm bringing to you this morning are Mr. Alan Alexander, who's a petroleum landman, and Mr. Frank Seidel.

We've handed out to you an exhibit book and the existing rules, along with a copy of brochures that Frank has provided to us from Baker Hughes -- I'm sorry, Frank, what's the source of the material? Baker Hughes --

MR. SEIDEL: Baker Hughes INTEQ, Baker Hughes Corporation.

And the reason for the information is purely to provide some description of some of the equipment that we use to horizontally drill with.

MR. KELLAHIN: There are three different pamphlets, Frank. Identify for us and we'll discuss in a minute each pamphlet.

Identify each one for me so that I --

MR. SEIDEL: Okay, we have a *Drilling Systems* pamphlet; one on *MWD*, which is an acronym for *Measurement While Drilling*; and one pamphlet for the *Navi-Drill Downhole Motors*.

MR. KELLAHIN: The concept that Meridian has proposed to you is one in which we have taken from our past horizontal cases. Meridian and I have presented probably two dozen horizontal cases to the Examiner.

I have given you a sample of one of the Examiner orders out of the Canyon Largo case, so you can see how the Division has handled these issues in terms of the hearing process.

With that background of information, then, Mr. Alexander and Mr. Seidel and I drafted what we filed on February 21st as a discussion draft of the proposed rule.

That discussion draft was generated in this fashion: Prior to filing with the Division, we circulated a working copy to all operators that we could find who had filed a horizontal application before the Division in the last several years.

And in response to that solicitation we obtained the cooperation and assistance of our other operator friends. They included Bill Hawkins with Amoco, John Rowe with Dugan, Ken Schramko with Phillips, David Boneau with Yates, Dow Campbell and the technical staff at Marathon for Marathon, Sally McDonald with Meridian; and others.

From those early drafts, then, we compiled what I will call a shopping list. And we filed a shopping list in terms of the proposed rule, which is what you have before you when you look in the exhibit book and look behind Exhibit Tab Number 1. That was the discussion draft application rule that we then recirculated to all parties that had done these type of cases.

Mr. Alexander and I decided on the strategy that we would have a detailed, all-encompassing rule, the idea being that if you had a suggestion on paper, it might trigger your thought process to recognize whether you actually wanted that item in the rule or not, rather than having a very simple rule as currently exists in Texas.

As a result of circulating that information, then, we have received comments, suggestions and ideas from other participants in the industry.

Mr. Seidel and Mr. Alexander will, this morning, present to you what Meridian believes to be their revised proposed rule. Others are going to propose suggested changes.

The New Mexico Oil and Gas Association, through Ruth Andrews, has also circulated these proposed rules and ideas to their membership, and she has received written comments from Arco and Texaco.

Our recommendation to you is that after the presentation this morning, the industry has done just about all we can do in terms of suggesting a rule, and we would like to recommend that you then, with your guidance and decision, suggest to the Division, to Mr. Stogner and to Mr. Carroll, that they then formulate what the Division would utilize as a final rule. We think the process has evolved to the point where we are ready for you to make a decision on what the rule ought to be.

The purpose, then, this morning is to bring a drilling expert with Mr. Seidel's experience in horizontal well technology, tell you the major parts of his activity so that as you see the rule proposed to you unfold, you'll understand why we did what we did. So that's the purpose of our presentation this morning.

And with those comments, then, I'd like to call Mr. Frank Seidel.

FRANK A. SEIDEL,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. Frank A. Seidel. I'm a senior staff drilling engineer with Meridian Oil in Farmington, New Mexico.

Q. Mr. Seidel, would you summarize for us your education and your employment background?

A. I have a BS degree in chemical engineering from New Mexico State University, and I've worked for 12 years for Amoco Production Company in various assignments throughout the company, and for the last year I've been employed by Meridian Oil in Farmington.

In that time I've drilled 14 -- or worked on 14 horizontal projects, in the Austin Chalk, in the Texas Pearshall field, in Mississippi, in the Wilcox field in Louisiana, and also in Oklahoma in the East Velma Middle Block field, and in New Mexico I engineered the first horizontal well for Amoco in the Mesaverde.

Q. Mr. Seidel, have you had an opportunity to participate in a proposed rule to be sponsored by Meridian Oil, Inc., for the establishment of an administrative procedure for obtaining of approval of the Division for the application of this technology in the State of New Mexico?

A. Yes, sir, I have.

Q. As part of that review, have you looked at the current Rule that deals with deviation tests and directional drilling?

A. Yes, sir, I have.

Q. And based upon that study and your background and information, do you now have certain opinions, conclusions and recommendations for the Commission?

A. Yes, I do.

MR. KELLAHIN: We tender Mr. Seidel as an expert drilling engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) If you'll turn with me, sir, to the first topic, let's look at what I've passed out to be the current Rule. It's Rule 111. And without going through the details of the Rule, describe for us whether in your opinion the existing Rule is adequate within the context of its procedure to handle the processing of the horizontal/high-angle directional drills that are -- wells that are the subject of this case.

A. No, I do not believe that it's adequate to support the administrative approval of applications for either drilling a high-angle or a horizontal or a deviated wellbore.

Q. As Meridian proposed to craft this rule, do you propose that Rule 111 be entirely eliminated, or simply supplemented and edited to be consistent with the adoption of a new rule that deals with the horizontal wells?

A. I believe that Rule 111 should be supplemented with the information -- further detailed information that we've come up with to support an administrative process for obtaining approval.

Q. Once that editing has taken place, then, what purpose would be served by the current Rule 111?

A. The current Rule 111 could still be utilized to handle wells where the wellbore was just deviated due to junk in the hole, where we -- what we call in the -- in our industry a blind sidetrack, where you've lost a piece of bottomhole assembly in the hole and you just want to go around it, you don't have any control of azimuth.

And that's one definition that we have in our proposed application, is that a directional well is any well where the azimuth is intentionally controlled, whereas in -- Rule 111 does talk about directional wells, but it doesn't provide for the administrative approval of an application in itself, it doesn't have the detail needed in order to provide that process.

Q. Let's turn to Meridian's proposed rule, which is found behind Exhibit Tab Number 2. This proposed rule has been edited using as its master the original proposed rule contained in its application. Let's turn and have you then help us understand how the rule, proposed rule, is organized.

A. Okay.

Q. Where would we find a definition, then, that would tell us the kind of creature that's going to be covered by these horizontal rules?

A. Okay, the first page that you find in our applications -- and then the subsequent several pages, three pages, the first three pages, you find definitions.

And I'd like to go ahead and give you a bit of background, why we decided to have such a detailed series of definitions.

The main reason was, in my opinion, to put everyone on a level playing ground, have everybody speaking the same language. Even within our own industry there's some confusion as to what people define as various terminologies. So this was our attempt to provide common understanding of our proposed rule.

And we even went as far as to characterize a vertical well, which is -- you'll find this under A (h); a horizontal, which you'll find under A (i); a high-angle well, which is found under A (j); and a directional well, which I spoke of earlier, which is found under A (k).

And then -- Do you want me to go on further about the characterization?

Q. Not just yet.

When we look on page 2 at the definition under (k) -- it says "directional drilled well" -- describe for us what you mean as a technical person when we make that statement.

A. What that means -- what this statement means, from my -- in my opinion, is that I have a preconceived plan of controlling both inclination and azimuth intentionally in order to steer my wellbore intentionally to a predesignated bottomhole target.

Q. How is that different, then, from what would still remain as the type of activity to continue to be controlled under Rule 111?

A. Well, as I previously stated, there are some situations that are common practice within the industry worldwide where we control inclination, but we don't necessarily control azimuth, and that's for steering away from old wellbores or junk in the hole, where there's no intentional control of the azimuth or no intentional bottomhole location to be penetrated.

Q. Under the proposal, then, anytime a well has an intentional deviation plus an intentional azimuth, it would fall within the context of this horizontal rule?

A. Right, it would be designated a directional well.

Q. Okay.

A. And all wells -- In my opinion, all wells that have a controlled inclination and azimuth, which includes horizontal wells, are directional wells.

So what I'm saying is that a horizontal well is just a type of directional well.

But since it is a new technology, it's been around for roughly -- commonly been around for roughly ten years, we felt that there was some characterization necessary so that once again we would provide a common ground for -- which industry and regulatory people -- to converse.

Q. The next definition is for the term "lateral". What does that mean to you?

A. The term "lateral" is -- to me, is a term that's expressively used to describe a horizontal wellbore. It's -- In my experience, it's never been used to describe a -- purely a directional well. It's a horizontal wellbore term.

Q. Can you further refine the term "lateral" to be subdivided into different types of categories?

A. Yes, we broke out the lateral into five different categories, and --

Q. Let's turn to Exhibit Number 3. If you'll look behind Exhibit Tab Number 3, there's a schematic that I think illustrates this next topic.

Without describing in great detail what this means, give us a summary of what you've illustrated here with this display.

A. Okay. Due to the fact that horizontal technology is still relatively new to some people -- there are some companies out there that still have not drilled their first horizontal well -- but there's been -- which I'll show later in my presentation.

But there's been a sharp increase in the number of directional or horizontal wells done over the last ten years. It's become a common practice within the oilfield.

And what I have depicted in Exhibit 3 are some common descriptions of the different types of radiuses and laterals that are found commonly within the oilfield today.

Q. Have these illustrations been reduced to a written portion of the definition section for the rule?

A. Yes, they have.

Q. Is there any significance attached, when we get to qualifying a particular well under the administrative order, to what category you put your well in, whether it's an ultra-short radius or a long-radius type of horizontal well?

A. No. Once again, this is a -- purely a description, a process, so that once -- when -- The intent here is that when industry talks to the regulatory body, that we're able to talk in common terms, and it's a -- It's purely a descriptive type of a process here.

Q. All right, sir. Have you reviewed Meridian's records to find an example of an application that went to a hearing --

A. Yes, sir, we have.

Q. -- the purpose of which was to demonstrate to the Division the appropriateness of the horizontal well and to obtain Division approval?

A. Yes, we have.

Q. And do you have an example of that?

A. Yes, I do. It's -- I'd like to refer to Exhibit 5.

Q. All right, and if the Commission please, Mr. Seidel is beginning to talk about the Canyon Largo presentation, which is the topic of the order I distributed.

If you'll pull that foldout, Exhibit 5, out, Mr. Seidel, before we talk about what you're showing here, describe for us how this fits into an administrative application.

A. The way it would -- Under the new rule?

Q. Yes, sir.

A. Okay. Well, under the new rule, the information that is depicted in Exhibit 5 is asked for under Section C, Number (3), (4) and (5).

So this is something that the Examiners would typically see, because it's asked for under our rule application.

Q. All right. When we look at this display, what are the parts in the display that fit in with the proposed administrative application?

A. Okay, I'm going to refer back to the proposed application, to Number C, Number (3), and I will read it:

a vertically oriented well plan view of subject well including true vertical depth of the top and bottom of the subject pool, true vertical depth, lateral length, estimated kickoff point, penetration point and degree of angle to be built in the project wellbore(s);

And Number (4) is:

a horizontal plan view of the subject well and its spacing unit showing the directional unit, the -- and drilling-producing window, including the estimated azimuth and maximum length of the lateral(s) to be drilled;

And Number 5 is :

A type log section on which is identified the top and bottom of the subject pool and the anticipated kickoff point(s) for the wellbore;

And the intention here, from a drilling standpoint, is to tell the story of what we want to do.

It shows the top exhibit -- At the very top of the exhibit shows a plan view of what we're intending to do. It indicates the area which will be affected and the surface location and the terminus of the horizontal wellbore also depicted, so that the person looking at this can get an appreciation for our plans.

Q. In this particular case, you are dealing with the Blanco-Mesaverde Pool, 320 gas spacing, and the project then included two spacing units consisting, then, of an entire section?

A. That's correct.

Q. Within that section, how was the proposed producing lateral to be oriented within the section? Where was it to be located? In the top part of the display you have Section 3.

A. Right.

Q. Within Section 3 it's been subdivided --

A. Uh-huh.

Q. -- and there's some setback dimensions.

A. Right.

Q. Within that display there's a red line.

What is achieved by controlling that red line, which is the producing lateral?

A. It's -- By keeping it within the spacing unit, by -- that's --

Q. All right, within that spacing unit, what are the setbacks from the section?

A. They're whatever was legal for this particular pool.

Q. All right. In this case, then, it's 790 feet?

A. That's correct.

Q. All right. Within that area, then, what is proposed under the administrative rules we're recommending to the Commission?

A. I guess I don't understand the question exactly.

Q. Are you proposing any setbacks for the producing lateral within the administrative rules?

A. Yes, we are.

Q. And how do you achieve that setback?

A. The setback is achieved in the same way a vertical well would be achieved.

Q. All right, for purposes of the Canyon Largo well, then, what was proposed?

A. A 790 setback.

Q. Within that outer boundary, then, what was the plan?

A. The plan was to not go outside of the boundary; it was to drill from one drill block to the next.

Q. Is that consistent with other orders entered by the Division in terms of a setback for the horizontal wells?

A. Yes, it is.

Q. And is that a concept crafted into the proposed administrative rule?

A. Yes, it is.

Q. When you look at the profile portion of the display, what amounts to this cross-section --

A. Uh-huh.

Q. -- describe for us what happens, as a drilling engineer, when you take this well and start at the kickoff point. Describe for us what you do.

A. Okay, what we do is, we have -- We pre-plan this existing profile, and what we do is, we try to follow this plan as closely as possible.

We have a kickoff point which -- the definition of which, that's where we begin our directional angle-build process.

And we build at a fixed radius, which is depicted in the definitions and also on the previous exhibit, and we build a curve up to a predetermined inclination. And in this case it was 88 1/2 degrees.

And also depicted here are the tops of the -- the top and bottom of the producing interval, which is required by the proposed rule.

It also indicates the pay zone that was targeted, and it also shows how we were attempting to stay within that target interval, or pay interval.

And it's also depicted on two type logs, on either end, which are intended to be offset wells.

And also on this particular exhibit, it also shows the dip of the formation.

So it's -- In my opinion, it's a very inclusive type of exhibit, showing the detailed drilling plan.

Q. Can you give us a short history of the development of the horizontal technology?

A. Yes, it was developed by -- Texas Eastern was the short-radius developer, where they used the old articulated collars, and -- But they were able to build in the -- along the lines of the short radius described in the definitions.

And then in the early 1980s, working with Arco, Texas Eastern, which became Eastman Christensen, developed the intermediate-radius technology. And I was lucky enough to be involved in some of the first commercial pools that became available, working in the Austin Chalk.

And at that point, it became more of a common drilling process in that it used common drilling equipment, used mud motors and existing telemetry equipment. And from there, it's been a constant improvement in our ability to directionally drill and to control our wellbores.

Q. Let's turn to some of the brochures that Baker Hughes provided and have you go through those and give us a taste for the kinds of advances in technology that have occurred and the types of equipment that you have and what you can achieve with that equipment.

A. Okay. Well, once again, I would like to state that horizontal drilling is now a worldwide accepted drilling practice.

The brochures that I have today that I'd like to refer to are: *Drilling Systems* brochure -- It kind of gives an overview of the type of tools that we use.

I'd like to also point out on page number 2, Baker Hughes is a worldwide company and they're real good at keeping statistics. They do our rig count, for example, within the United States.

But this gives an indication since 1986. If I'm reading this graph right, there was approximately 1000 directional horizontal wells done in the country. And as of 1993, if I'm reading this graph right, it looks like about 14,000 were done in 1993. So that's a tremendous growth in the use of directional horizontal technology.

The next page, page 3, gives a cutaway view of a mud motor. These mud motors are called positive displacement motors, and they work very much like a progressive cavity pump, which a lot of you may be familiar with. But it works by pumping mud, pumping drilling fluid through the motor and causing the bit to spin, and the drill string is fixed and you're able to control which direction the drill string goes by some telemetry equipment which I'll talk about later.

But we have the capability -- the industry, not just Baker Hughes INTEQ, but there's many other companies within the oilfield that have this capability, and it's all similar.

I'd like to refer to page 7, 6 and 7, and it gives you an idea of -- it shows some of the -- First of all, I'd like to point out the maximum build rates for Baker's Navi-Drill motor configurations. And these fall right in line with the definitions that were provided in our Application.

And it also shows the different types of motors, short-radius motor, and then a -- the AKO/ABS-type motors and DTU can either be used on just a directional well or a horizontal well, and they are commonly used that way. And we have very good capability.

Page 9 shows a plan view of multi-horizontal wells off an offshore platform, to give you an idea of what our capabilities are as far as knowing exactly where our bottomhole locations are. And this is an extreme necessity offshore, because you don't want to drill into another one of your wellbores.

So we feel that in the drilling industry we have very good capability for controlling our directional well paths and providing any regulatory body a survey indicating exactly where a bottomhole location is.

And I'd like to -- That's all I have for this.

And these other two brochures, the *MWD* brochure just speaks about -- Once again, MWD is an acronym for measurement while drilling.

It's something we typically use throughout the world to not only tell us where we are from a directional standpoint by providing inclination surveys and azimuth readings, but we've also advanced to the point where we can get formation information, like gamma-ray logs, nuclear logs, resistivity logs, porosity information.

So there's been a continuous improvement of the technology, and a lot of it was spawned from the increase in directional and horizontal work that's been done over the last ten years.

And the last brochure, the *Navi-Drill Motors*, just gives a little bit more detail about the mechanical workings of the motor. It talks about the definition of a positive displacement motor.

And it's here purely for -- just to provide a common understanding, once again, of some of the tools that we use, typically, in the oil field.

Q. Let's turn to page 4 of our revised proposed rule and look at subsection C, and let's walk the Commission through the parts that you now suggest to us ought to be utilized in a submittal to the Division for administrative approval.

You've had a chance to work on the original draft application and to reconsider each of the parts of an application. Do you now have recommendations for the Commission as to what are the necessary components of an application?

A. Yes, sir, we do, and they're outlined in Section C, (1) through (12).

Q. All right, sir. Let's go through how you would recommend an operator apply for an application in terms of the pieces of the request that he should furnish information.

A. Okay, what this is based upon is something that's already typically been done on cases that have been heard before the Commission, and what we tried to do was go through our cases, as well as other operators' cases, and find things that we felt would be necessary exhibits for the Commission to have so that they could make a determination of -- from an administrative standpoint, whether to approve an application or not.

And they are -- Number (1) is a plat indicating the section, township and range that the well is to be drilled in and the project area, the proposed surface location, the drilling producing area for subject well, any existing wells in the proposed project area or adjoining sections, and all offset drilling units in the applicable pools and all of their associated operator well and well location and spacing units, which is a typical exhibit.

Q. You're recommending striking the specifics of a nine-section plat, are you not?

A. That is correct. And the reason for that is that -- as Mr. Alexander will indicate, that we're fortunate enough to live in a -- work in a Jeffersonian-laid-out type of a survey system, but there are some areas where it may not be applicable just to have a nine-section plat. You might want to have more than a nine-section plat or less than a nine-section plat.

But the intent here is that we show the correct information.

Q. Part (2) is to simply put a label on the kind of horizontal project you're proposing?

A. That's correct.

Q. And that would track the definition section so that everyone would know if you had a short-radius application or a long-radius application of the technology?

A. Right, and that's purely for communication in the applicant process.

It's also to provide a means for the industry to track the different types of wellbores that are currently being drilled in different types of directional wells.

Q. We've already discussed sub (3), which was the submittal of a graphic representation of the plan view and the vertical view of the well plan, as you've shown in your exhibit book?

A. That's correct.

Q. And (4) would be the horizontal plans?

A. Right, (3), (4) and (5) have already been presented.

Q. All right. You're proposing to strike the initial suggestion of some type of written summary concerning drilling and stimulation, which is (6)?

What's the reason to delete that?

A. Well, the first reason is that this information is generally already provided through an APD or a sundry process.

And oftentimes when we're doing a horizontal project, we don't know exactly what we're going to do. We have an indication -- We have an idea of where we're going to put our lateral or our wellbore, but we don't oftentimes -- don't have all the data. We may be out processing seismic data up until the drilling. But we -- It's not going to change the spacing that's associated with the horizontal wellbore, but it may -- the exact details of the plan may be unknown at the time of application.

Q. Are the Division orders currently allowing the operator the flexibility to make these types of changes in the field, so long as you honor the side boundary setbacks for your producing lateral?

A. Yes, they do.

Q. Subparagraph (7) is proposed to be deleted. What's the reason to strike that?

A. We feel that this is already adequately covered -- Let me backtrack.

One thing that we tried to do here was, anything that was covered already, any rules that were already covered in a vertical well situation, we felt didn't need reiteration here.

And as far as plugging and abandonment, we feel that there's adequate rules available to -- that provides for the plugging and abandonment of a -- of any wellbore, regardless of the configuration.

Q. Okay. In reviewing the cases that went to the hearing, those cases almost always deal with a request for and the approval of some type of allowable to be assigned to the horizontal well?

A. That's correct.

Q. And subparagraph (8) proposes to have some request from the applicant as to what type of allowable and method to be assigned to the horizontal well?

A. That's correct.

Q. All right. So you propose to leave that in?

A. Yes, sir.

Q. All right. Sub (9), what is that?

A. In the event there are any existing wells within the project area producing from the same pool from which the project well is intended to produce, then the applicant shall submit engineering and technical data, including a written summary, which demonstrates why any existing wells are unable to effectively drain the project area.

And this is something that we've already been presenting in the hearings. It's an exhibit, and we propose to leave it in. But, you know, we -- because we felt that any data which will provide further understanding for the Examiners to approve the application would be beneficial.

Q. You're proposing at this time to strike -- While the edited draft does not show that, you propose to delete paragraph (10) as to the cost and the consent of the working interest owners in the spacing unit?

A. That's correct.

Q. And number (11), which you also propose to strike, deals with the same topic insofar as it talks about the participation of the interest owners within the spacing unit that pays for the well?

A. That's correct, this -- In our opinion, this deals with contractual type of relationships and --

COMMISSIONER WEISS: What are you talking about? (11) here, did you say?

MR. KELLAHIN: (10) and (11).

(10) is an affidavit saying that the working interest owners in the spacing unit have consented and that there's a disclosure of cost.

And (11) deals with notification by the applicant that he's notified all those parties within the spacing unit.

COMMISSIONER WEISS: And you want to strike that? Is that what you said?

MR. KELLAHIN: That's Mr. Seidel's recommendation, that those two items be deleted.

THE WITNESS: And the reason is, we feel that this is an internal -- you know, a contractual type of a relationship between us and our working interest partners.

Q. (By Mr. Kellahin) All right, sir. Let's turn, then, to the last part of the submittal, which would be subparagraph (12), and what does that involve?

A. "A statement or plat showing the names and addresses of all operators of spacing units, or working interest owners of undrilled spacing units offsetting the unit in which the project is located and attesting that applicant, on the same date the application was submitted to the Division, has sent notification to all those parties by submitting a copy of the application to them by certified mail return receipt requested."

Q. And that's currently what's being done for the hearing purpose, is it not?

A. Yes, it is.

MR. KELLAHIN: That concludes my examination of Mr. Seidel, Mr. Chairman.

We're going to call Alan Alexander to talk about the other parts of the proposed rule, but that concludes my direct questions of this witness.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Are there any questions of the witness?

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, I just wanted to make clear in my own mind here that (11) and (12) are -- one is for within the unit and (12) is for anybody outside the unit?

A. That's correct.

Q. And you don't propose to quit notifying --

A. Oh, we're going to --

Q. -- people outside of the unit?

A. -- we want to keep 12 in.

Q. Very good.

Let's see, I had a couple others too.

Do you think that -- You had a lot of definition, detail.

A. Uh-huh.

Q. Do you think that will change as the science progresses?

A. No, that's one thing that we made some changes to, that we pretty much have it covered in that -- The only thing that's been changing is the lateral length. And in the original draft, lateral length was in there.

And like -- they said that -- in the original draft, I believe, short radius was 750 feet. Well, I don't agree with that. I already know some places in the world where short radius, they're up to 1500 feet.

So -- But the radiuses are pretty well standard.

Q. Well, I guess my question is, maybe it's not necessary to define it because it might change next year. You already know of some this year, so -- I don't know.

A. Yeah. It's my opinion that these are standard -- pretty well standard types of radiuses.

And once again, the -- we have it covered from -- all the way -- from zero all the way up to 90 degrees, basically.

Anything less than two degrees is a typical directional well, two degrees per hundred. And we have it -- 90 degrees in one foot, that's about as severe as you can get.

So we pretty well have it covered from -- the whole spectrum.

Q. And then would you tell me again why you think (9) is necessary?

A. Well, we're kind of -- We took this one out and put it back in, took this one out and put it back in. And the reason why we left it in there was to provide an understanding for the Examiners, to give them further data to support our application for administrative approval of the horizontal well.

Q. Some people may be of the opinion if you want to drill a dry hole, go ahead.

A. That's right.

(Laughter)

MR. KELLAHIN: The issue has come up within the -- Mr. Chairman, Commissioner Weiss, the case has -- the issue has come up within the context of the horizontal well being a well in addition to the well spacing density pattern for that pool.

And it is not universal, but it is often presented to the Examiner to demonstrate that the horizontal well is going to recover additional reserves within the spacing unit that's not achieved with additional vertical wells.

And so Frank's right, we keep putting it in and taking it out, but it's internal within the spacing unit.

COMMISSIONER WEISS: Is it a waste issue? It's not a -- I don't understand what's in there, frankly.

MR. KELLAHIN: Well, it could be one or both.

It could be a waste issue in terms of drilling an unnecessary well.

And it could be a correlative-rights issue in terms of whether the interest owners within that spacing unit want the additional horizontal well, are satisfied with the two vertical wells.

Now, that's often a contract issue among those parties, but it's also a regulatory issue for regulators when they decide what your well density is for a pool. The horizontal well counts as another well.

It's a judgment call, and that's why we air it with you, because it's the kind of thing that you need to make directions to the Division on how to handle this issue if there is to be a rule that deals with it.

COMMISSIONER WEISS: Yeah, I have no other questions.

Thank you.

CHAIRMAN LEMAY: Commissioner Carlson?

EXAMINATION

BY COMMISSIONER CARLSON:

Q. In your notification I guess, under paragraph C (12) --

A. Uh-huh.

Q. -- you envision as part of that notification, notifying those owners and operators what their rights are?

In other words, do they have -- notifying them that they have to submit an objection within 20 days? Or it's just a copy of the application that we're --

A. I have to refer that to Mr. Alexander.

MR. KELLAHIN: Mr. Alexander will cover that, Commissioner Carlson.

But the concept would be that that notice is similar to what we do now for administrative notices, that the 20-day notice period, the applicant sends a copy to the offsets and says, You need to file an objection or you don't get hurt.

COMMISSIONER CARLSON: Okay, and it does inform them that they have 20 days to do that?

MR. KELLAHIN: And perhaps this needs to be edited to make that specific, but that was certainly our purpose.

THE WITNESS: Yeah, it's the same -- under the same process that we've been notifying.

MR. KELLAHIN: If you'll look at --

COMMISSIONER CARLSON: And Mr. Alexander will address those issues?

MR. KELLAHIN: Yes, sir. If you'll look at subsection D under that, it says the Division will approve it when...

COMMISSIONER CARLSON: Right, yeah, I understand that. I just -- You know, if an operator doesn't know he has that right -- well --

MR. KELLAHIN: The point is well taken, and perhaps we should edit that to make it specific.

COMMISSIONER CARLSON: Okay. I'm sorry, Tom, what else is Mr. Alexander going to testify to?

MR. KELLAHIN: We're going to go through how the Division has handled the allowable allocations --

COMMISSIONER CARLSON: Uh-huh.

MR. KELLAHIN: -- give you an example of how the rest of the parts of the application are crafted, particularly in terms of notice, that kind of thing.

COMMISSIONER CARLSON: Okay. I have no other questions. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. As I understand it, this application for administrative approval would not cover what we call drainholes where you just go out a couple hundred feet. That would be more than under the administrative approval for a vertical hole?

A. This will cover all directional wells.

Q. Where you have a multiple fishhook-type situation at the bottom, this would cover that also?

A. Yes, sir. Any directional well drilled within the state could be handled under these definitions.

Q. There was some talk, I know -- and maybe I just picked this up -- that that type of well where you go down and drill out three or four 200-foot laterals --

A. Uh-huh.

Q. -- as long as you're not going very far out from a 200-foot radius, we'll say, around the vertical, would be basically the same as a vertical well, it would maybe not have to be covered by the detail in here.

Was that a topic of discussion at all?

A. Not that I know of. Multilateral wells are spoken about under Section B, Number 4.

Q. Uh-huh.

A. It talks -- The project well includes either a single lateral or multilaterals which conform to conditions 1 and 2 that are already talked about as far as the spacing.

So as far as high-angle drill holes, anything --

Once again, this takes the burden -- I think this also takes the burden off the Commission that any well that has intentional control of inclination and azimuth is a directional well and will be handled under this application.

Q. Uh-huh. And could I refer you, Mr. Seidel, to Exhibit Number 5 just again?

A. Uh-huh.

Q. In terms of that -- I understand that without seeing the log, you certainly don't know where you're going to perforate the well, but the assumption is when you submit this that you will be perforating within that drilling window and not outside of it?

A. That's correct. And Mr. Alexander will -- He has some exhibits to indicate that.

Q. Okay. One final question for my own clarification. This measurement while drilling, what's the tolerance of error within that? Can you tell within a few feet of where you are when you're drilling or --

A. Yes, sir. There is a -- what they call circle of uncertainty, but it's as good as -- As far as I know, in my experience, it's as good as the best survey instruments that we have, which would be a gyro survey. It's very similar to that, as far as accuracy. So it's within 10-percent accuracy.

Q. Which is what in feet, offhand?

A. Well, if it's a 100-foot radius, it's within ten feet.

Q. Within ten feet?

MR. ROBERT ORR: Mr. Witness, with what?

THE WITNESS: I believe it's with -- I believe the -- As far as I know, the circle of uncertainty is within 10 percent.

Q. (By Chairman LeMay) That was translated within ten feet, you say?

A. I believe so.

Q. Ten feet would be the maximum you could off of drilling?

A. Right. It may give some indication in here. Let me look quickly.

But it's -- They're becoming as accurate as any other type of survey that we've had before, which would be a gyro survey, is the most accurate.

And right now, I believe what's acceptable within the Oil and Gas Commission are multi-shot surveys. Any kind of inclination and azimuth type of a reading is accepted. So this is just one type.

CHAIRMAN LEMAY: Uh-huh.

THE WITNESS: But there's many types.

CHAIRMAN LEMAY: Okay. I think Commissioner

Weiss had an additional question.

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, follow up on Mr. LeMay's comment there about lateral length.

Do you think there's any need for -- cover a minimum lateral length in here or --

A. No, sir.

Q. The direction is purely enough, huh?

A. Yes, sir. I think the reason is that the spacing unit is going to determine lateral length, typically, or mechanical considerations.

Q. Well, I'm talking about short laterals, 20 feet long or something. Say some guy -- I don't know if this becomes a practice or not.

A. I don't think it needs to be --

Q. Just directions?

A. Yes, sir.

COMMISSIONER WEISS: I have no other questions.

CHAIRMAN LEMAY: Commissioner Carlson?

FURTHER EXAMINATION

BY COMMISSIONER CARLSON:

Q. Mr. Seidel, I'm unclear as to when an applicant would use the existing Rule 111 and the proposed rule. Could you explain that a little bit?

A. Uh-huh. Well --

Q. Explain the different -- as you envision the difference between the two.

A. Okay. What I see Rule 111-A is in addition to Rule 111.

It's up to the Commission to decide whether to take Rule 111 and overhaul it to include all of the considerations that we have in Rule 111-A, or to take some of the redundancy that's in Rule 111 and 111-A and restrict Rule 111 to a single rule that will handle only what I call deviated wellbores.

And the deviated wellbore is any wellbore where you have a control of inclination but you don't have a control of azimuth.

Any well that has a control of inclination and azimuth will be considered a directional well and will be provided by -- under the provisions that we have in Rule 111-A.

But it's up to the Commission if a whole new rule is necessary or can be incorporated with the existing Rule 111-A.

But what I would ask is that we go back through, that the Commission goes back through, and takes out any kind of conflicts or redundancies between the two rules if it was going to be merged together.

COMMISSIONER CARLSON: Okay, thank you.

CHAIRMAN LEMAY: Additional questions of the witness?

MR. CARROLL: Yes, sir, Mr. Chairman, I have a couple of questions.

CHAIRMAN LEMAY: Yes, Mr. Carroll?

EXAMINATION

BY MR. CARROLL:

Q. Mr. Seidel, is it your proposal that the Division can administratively approve the extension of setback limits?

A. I'd rather refer that question.

Could you wait and refer that question to Mr. Alexander?

He's an expert witness in that regard.

MR. CARROLL: And the other question I'll refer to Mr. Alexander too.

That's all I have, Mr. Chairman.

THE WITNESS: Thank you.

CHAIRMAN LEMAY: Any other questions of the witness?

If not, he may be excused.

THE WITNESS: Thank you.

MR. KELLAHIN: I'd like to call Mr. Alexander at this time, Mr. Chairman.

ALAN ALEXANDER,

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

A. Yes, my name is Alan Alexander, and I'm currently employed as a senior land advisor with Meridian oil in the Farmington, New Mexico, office.

Q. Have you been involved on behalf of your company in obtaining information in formulating a proposed draft rule to be adopted by the Commission for administrative processing of horizontal wells?

A. Yes, sir, I have.

Q. Have you also been involved on behalf of your company in the horizontal well applications they have filed with the Division, which have been processed through the hearing procedures of the Division?

A. Yes, I've been involved in several of those applications.

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

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) Mr. Alexander, let's turn to a schematic so that we can better understand some of the definitions.

If you'll turn behind Exhibit Tab Number 6, let's look at that display. Would you identify it for us and describe for us how each of these terms is utilized, then, on this display?

A. Yes, this display is meant for informational purposes for everybody that is involved in this hearing this morning. It's not intended as one of the data display items, just strictly for a discussion of the efficiencies and the terms that we're using in the proposed order.

The exhibit behind Exhibit Tab Number 6 is a plan view of a generic horizontal well, and this particular one I drew up thinking about a 320-acre spacing unit, typical gas spacing unit, or even a 160-acre typical gas spacing unit.

It's scaled, and the setbacks that are employed here are actually 790 feet from the drilling unit boundary.

And if you'll look up -- I have designated certain portions of this plat, and if you'll look at the very top, I have an arrow pointing to the setback for drilling and producing area. And that's the internal rectangular hatched area. That's the distance it is away from the outside of the drilling unit.

And the drilling unit is the larger area, and you'll see an arrow pointing to it that's in the cross-hatched. That would be the proposed drilling unit or drilling units in the case of the 160-acre spacing.

Q. All right. Let's take that point first.

When you look at how the Division has handled the approval of these wells through the hearing process, what have they allowed operators to do in terms of locating that well on the surface, in relation to this setback drilling producing area?

A. Well, historically on vertical wells, the wellbore, of course, would have to be located inside the setback area, because that's ultimately -- the wellbore is ultimately directly underneath or approximately -- very close to directly underneath the well, and so it would have to be within the setback areas.

We've had testimony in prior cases and developed a strategy about horizontal wells in that we don't believe it's necessary any longer for horizontal -- the wellhead itself where you start penetrating the earth, it is not necessary for that to be located within the setbacks for each applicable pool.

The only thing that we see that is necessary for a horizontal well is that, if you'll drop down to the fourth -- or drop down to the fifth definition on this plat, it says "producing interval", and what I've shown is a borehole, a horizontal borehole, and I've colored it black from the area that it penetrates, the setback area, to the terminus of it, which I have run all the way to the other side of the setback area. Now, it's not necessary that the terminus has to go that far, but that's as far as we're proposing that it can go.

And so what we're only restricting here is -- We're not restricting the surface location at all. That's what we're proposing not to restrict. We're only going to restrict the producing interval of the borehole, and that would be strictly limited to the setback area for the applicable pool.

Q. Has that been a solution adopted by the Division when they handle these on a hearing basis?

A. Yes, that's correct.

Q. That they allow the operator the flexibility to satisfy certain surface conditions, as well as the choice of the operator to have the well located within a normal vertical well setback?

A. That's correct.

The other thing that I wanted -- if you could visualize this -- and I didn't show it, but I have shown a determined azimuth for this well in the direction that it's going.

The order is suggesting that that borehole can actually go anywhere from that surface location point, as long as the producing interval is restricted to the setbacks. It could have gone to the north, it could have gone more to the south, it could have gone to the west. And that is not really important, and we're asking for flexibility on the behalf of the operator to make that determination at the time that he drills the well.

We have in the past -- We've drilled a vertical pilot hole in order to run fracture-finding logs, and from those fracture-finding logs we can determine what the directions of the fractures might be.

For instance, if you'll turn back to the plat that Mr. Seidel used under Number 5, if you'll fold that out for just a second and you look up at the top on the plan view, you'll see the azimuth of that borehole extended out beyond the plat, and you come out to a histogram of the fracture in the area.

That's typically what we might do. We might drill a pilot hole first, run the fracture-finding logs in there, see which direction the fractures run, and then orient the wellbore. I mean, we may have had a predetermined orientation, coming to the hearing, that suggested that it went a little bit different direction.

But after we run those logs we say, Well, no, we're a little bit wrong, the fractures in this area run a little bit different direction. Therefore it's necessary for us to reorient the wellbore.

And we're asking for that flexibility in this order, that we can reorient the wellbore either before we actually commence the wellbore or possibly as we're drilling the wellbore.

But the restriction is that it cannot produce anywhere other than the producing interval, no matter which direction it's finally oriented.

Q. And that's a flexibility currently allowed under the orders entered by the Division?

A. That's correct.

Q. All right. Let's look at that producing lateral, then. If you'll look behind Exhibit Tab Number 7, you've got a vertical view of this example?

A. Yes.

Q. All right, let's describe and discuss this display.

A. I wanted to follow up with the prior exhibit, with this Exhibit Number 7, to give you a vertical profile of what I just said, and this exhibit is constructed much on the same lines as the prior exhibit.

I have some dashed setback lines in there that would indicate the area that is permissible for completing the wellbore, and I have drawn the vertical portion of the wellbore outside of those setbacks, just as I illustrated that in the last exhibit.

And you'll see that actually in this one I'm illustrating a situation where the wellbore, as we're building our build rate from our kickoff point, can actually penetrate the target formation. But as you'll see, I have definitely restricted the producing interval of that wellbore to only the setback area.

So what we're suggesting is that you can actually drill a wellbore, and you can penetrate the target formation before you get to the setbacks, but you cannot complete outside of the setback area.

And I think that's the protection we've built in for correlative-rights issues, particularly for offset owners and operators.

But we do want the flexibility to set the surface of the wellbore and the configuration of the boreholes such that mechanically we can devise the best directional wellbore, and we don't want to be restricted by the placement of the surface location to accomplish that task.

And I think we're fully protected when we restrict the producing interval of that wellbore to the setback area.

Q. In addressing the notification to the offsets, let's turn to Exhibit Tab Number 4 and have you describe for us how Meridian and other applicants are satisfying the notice requirements for these types of activities.

A. Yes, this is in relation to the question that was asked about our notice, and more directly with regard to paragraph -- subparagraph (12), where we do believe that we need to notify the offset owners or operators. If there's not an operator there -- We would be notifying the operator if there's an operator there, but if there's no operator of an existing well, then we would notify the owners in that particular drilling block.

We do this by certified return receipt mail, and the subparagraph D under (12) provides that -- it's the normal provision that we have for administrative rules, is that if an operator wants to object after being notified, he must do so within 20 days. If he doesn't do so within 20 days, the Division has the authority to go ahead and approve the order.

Now, they also have the authority to go ahead and set for hearing if they feel that's necessary to do that.

But this would be -- This is the standard type of plat that Meridian uses. There could be other plats and other ways to notify the offset owners.

The idea here is that you notify the offset owners by certified mail so that we know that all of those people have the opportunity to offer comments or suggestions to the Division before the order is approved administratively.

Q. Follow up with the next display after that first plat and describe for us what that shows.

A. This plat we have historically been furnishing in all of the hearings. It's a plat that simply depicts -- In this case, it is a nine-section area, but that's not necessary that it should always be a nine-section area. We just have the flexibility of doing that here since it's a Jeffersonian survey and we have nine sections surrounding it.

But it depicts the offsetting wells that would -- in the offsetting sections to the type of well that's offsetting out there.

It's basically information for the offset owners and for the Division so that they can look at the particular application and see if there's anything that they think causes them any kind of concern from a correlative-rights or a waste standpoint.

Q. Let's turn now, Mr. Alexander, to the topic of what the Division, after noticing hearing, has been doing in terms of assigning a project allowable for the horizontal wells.

If you'll turn to page 6 of the redraft of the proposed rule --

A. Yes, sir.

Q. -- under subparagraph E, let's talk about the original concept, and then let's talk about the proposed change.

First of all, what is the typical solution the Division utilizes for assigning an allowable for the horizontal well?

A. The typical solution that I'm aware of -- and I certainly haven't been involved in all of the cases, but from the ones that Meridian has been involved in it's been that if the borehole cuts the drilling block -- a drilling block -- for the particular pool -- and that could be anywhere from 40s to 320-acre units -- but if it cuts one of those drilling units, then that drilling unit is included in the calculation of the allowable, and it's a multiple of those drilling blocks that are actually cut by the wellbore.

There has been discussion and debate about this, and it's not an easy topic to fully resolve, by any means. But we have offered a possible solution to that.

Q. All right. Let's turn, to illustrate what you're suggesting as an alternative way to set an allowable, to the display behind Exhibit Tab Number 8.

A. The display that I've presented here is just really a graphical representation of the wording that we have provided the Division and the other participants in paragraph E.

And perhaps the display is a little bit easier to understand than the wording is, and maybe if you look at the display and then go back to the wording you'll more easily understand it.

Again, on the display behind Exhibit Tab Number 8, you can readily see in this instance the 40-acre drill blocks. In this case I chose to use 40 acres because it's one of the situations that you could run into that would involve more drill blocks than other situations, obviously.

Q. All right. Let's take this and let's say the operator has dedicated the east half of the section as a project area and that he -- 40-acre oil spacing -- and that the operator is successful in drilling a lateral of the length shown on the display.

Show us what the Division commonly does in terms of assigning allowable. If it's on 40-acre oil spacing and you get 100 barrels a day per 40, how would you calculate the allowable for this well?

A. Well, you can determine from this exhibit which of the 40-acre tracts the wellbore actually penetrated or cut. And they would be the northeast-northeast quarter, the southeast of the northeast quarter, the -- and all of the quarters in the southeast quarter except for the southeast of the southeast quarter.

And that would -- To date, that has typically been the allocation. In other words, you would take those quarter sections and the allowable for each of those, and add them together to come up with a total allowable for the wellbore.

Now, the problem that you get into is that if you'll look down close to mid-section line on this particular exhibit, you'll see that that borehole comes very, very close to the southwest of the northeast quarter. In fact, it's almost between that quarter section and the northeast quarter of the southeast quarter.

Looking at that, you might suspect that that wellbore, in fact, would drain the southwest of the northeast quarter.

Under the current approach, we would not receive any allowable for that quarter section, even though it had been dedicated to the well.

So in an attempt to resolve some of that with some of the common usage that the Division has employed to date, what we're suggesting is that you run a line perpendicular from the wellbore, out from the wellbore, based upon the setback footage for the applicable pool.

Now, in this exhibit I've scaled it, and this is a 40-acre oil pool that has 330-foot setbacks. And so those perpendicular lines running out from the wellbore -- and in my exhibit they're not exactly perpendicular, but that would be the intent -- you would run out 330 feet from that wellbore.

And if that line intersected an undrilled, unpenetrated drill block, then perhaps what we ought to do is include that drill block in the allocation allowable.

And the rationale behind that is, we don't have to come up with a comprehensive study of the drainage radius of a lateral horizontal wellbore. That could be very complicated and time-consuming to do that.

And in using the setbacks, the Division has historically employed those in pools, and those are built around the drainage concept. While they may not be exactly accurate, they do employ the drainage concept. And so we're using, actually, a concept that we've used for many years, if we decide to do this.

And we offer this as a possible solution to the problem of including the correct number of drilling units in the allocation allowable.

MR. KELLAHIN: Mr. Examiner, that concludes my direct examination of Mr. Alexander.

At this point we would move the introduction of Meridian's exhibit book, which includes Exhibits 1 through

8.

CHAIRMAN LEMAY: Without objection, those exhibits will be entered into the record.

Are there any questions of Mr. Alexander?

MR. CARROLL: Yes, Mr. Chairman, I have a couple.

CHAIRMAN LEMAY: Yes, Mr. Carroll?

EXAMINATION

BY MR. CARROLL:

Q. Mr. Alexander, is it Meridian's proposal to allow the OCD to administratively approve the extension or expansion of setback limits?

A. No, sir, not in this application. We would abide by the existing setback requirements for each applicable pool.

Q. And the Canyon Largo unit application involved in Exhibit 5 included two spacing units?

A. Yes, sir.

Q. How would different ownership interests in those two spacing units affect administrative approval under your proposal?

A. Well, that's -- we would have -- That's really a contractual matter, as we see it, that we would provide for the distribution of the revenues to the working interest owners and the burden owners contractually, if we didn't already have a contractual vehicle to do that such as a joint operating agreement.

And that could vary, depending upon the application, on how you want to approach the sharing of the revenues.

But historically, that's been a contractual issue, and I would perceive that it remain in that context.

Q. So it wouldn't affect the administrative application or --

A. No, sir, I don't believe we're asking the Division to solve our contractual problems at all here. I think we have to solve those beforehand.

MR. CARROLL: That's all I have, Mr. Chairman.

CHAIRMAN LEMAY: Thank you, Mr. Carroll.

Additional questions?

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yes, sir, Mr. Alexander, I kind of recall there being something here, like on Exhibit 7, where the well caved in and the operator came in and said, Well, we want to have -- we want to perforate now and complete in the setback area because we need to -- But as I recall, the offset operator didn't want to do that -- didn't want them to do that.

That's the only problem I see coming out of this -- what you've proposed.

A. Yes, sir, in our proposal he would not be allowed to perforate in that area without coming forward to a hearing to do that.

This rule does not allow a person to perforate anything outside of the setback area.

Q. Okay. And then on your proposed twice -- wellbore radius twice the setback distance, were you guys just talking about the ownership problem there if in example -- in Exhibit 8, in that northeast -- well, that section up there, the area, the 40 acres that that's not cross-hatched?

Let's see, if -- or the one right below it. Does that guy have to participate in the AFE, does he have to help pay for the well, or how does that work?

A. Yes, sir, because what we would have done in the beginning in this example is, we would have designated the entire east half of the unit for the drill block for this well.

And then contractually we would have resolved the participation problems before we come to you for administrative approval.

So to answer your question, yes, sir, he would participate.

COMMISSIONER WEISS: Thank you, that's all the questions I have.

CHAIRMAN LEMAY: Commissioner Carlson?

EXAMINATION

BY COMMISSIONER CARLSON:

Q. Yeah, following up on that question, if the owner -- Well, let me back up.

If the language in paragraph E on Exhibit 2, the original language there -- and looking back at Exhibit 8, the owners in the southwest of the northeast there would not be contributing at all under the original proposal; is that correct?

A. No, sir, that's not correct. Really, the -- Let's back up and say again, when we file our APD to drill this well, we would designate the 320-acre unit.

That's really the same for our proposal and the original language and what's been done to date. That hasn't changed. All of those people would participate in that wellbore.

The only thing that we're talking about is setting an allowable for the wellbore, not the participation in it. It's two separate matters that we're discussing now.

Participation is set when you file your APD and you designate the drilling unit. All the people in that drilling unit would participate in the well.

Q. Okay. So you envision that being a 320-acre drilling?

A. Yes, sir, in this example.

Q. In that example?

A. Yes, sir.

Q. All right. When you give notice, now, do you typically notify royalty owners in adjacent acreage?

A. In the event that there is not an existing wellbore offsetting the unit that you want to drill to the same formation, we would notify all owners of production.

Now, if those royalty owners have signed an oil and gas lease, the practice currently in the Division is to notify the oil and gas lessee of that, because they are the owners of the right to drill and participate in that production.

Q. If it's unleased acreage, would the land owner get notice?

A. Yes, sir, the mineral owner, if it's unleased, would be notified.

Q. How many applications for horizontal drilling before the Division have you been involved with?

A. Just off the top of my head, probably six or seven hearings to drill horizontal wells.

Q. Has any party intervened in opposition to the proposal in any of those hearings?

A. No, sir, the only real debate in those hearings centered around the allocation issue. It didn't center around the fact that we wanted to drill a directional hole and around where the directional hole was to be drilled and the producing interval of that wellbore.

We did ask the Division for a special bonus in the beginning when we -- first application for a bonus allowable to justify the technology, and ultimately we were denied that bonus allowable.

But as I recall, that was the only area of any controversy on any of the horizontal wells that we drilled.

Subsequent to that initial application, we have not asked for any bonus allowable on any horizontal wells, so that has not come under contention.

COMMISSIONER CARLSON: That's all I have.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Okay. Once more, on page 6, Section E, I'm -- that may be a controversial point. Or maybe it's just a point of clarification for me, Mr. Alexander.

Back to that southwest of the northeast, I guess you're assuming that would be a nonpenetrated proration unit that you would add onto the allowable. But they would also join in the -- in the designated proration unit, so to speak?

A. Yes, sir, and that's not determined after the fact. That's determined before the fact.

So let me go over that -- I probably haven't explained that very clearly. Let me go over that one more time.

At the time we proposed drilling the well, we would file an APD, and we would propose the drilling unit for that well to be the entire east half of this section. We would contact all the owners in the east half of that section, and they would either participate, or perhaps we would construct some kind of a nonconsent proposal for them to not pay for the cost of the well but ultimately participate in it.

So we would set all of those things up front, and so everybody is in the well and everybody's participating that is going to participate.

Then we go drill the well, and we determine ultimately what the azimuth and direction of the wellbore is. Now, we complete the well.

Then we come to the Division for an allowable after we file our completion report.

Then at this point in time -- Everybody's already in the well, but the only thing we're determining now is what allowable that wellbore is actually going to have.

Q. But you're going after a 320 for -- like a communitization agreement, but you -- You would do that for a San Andres well that would be on 40-acre spacing?

A. If you contemplated that your wellbore was going to penetrate substantially all of that 320-acre block.

Q. And then you would invite in all the interest owners in the 320? What happens if an interest owner had some dryholes in there and you had an offset competing 320 that didn't have any dryholes?

What I'm looking at is competition in the reservoir based on extending the spacing unit to a communitized area and then asking for an allowable based on that communitized area without productive limits basically being established by any other method?

A. Yes. Now, this example really contemplates that this is the first borehole in this particular spacing unit.

I didn't try to go through and describe the various scenarios that you could get into if you had existing wellbores which have already existing dedications to them, such as -- We may have a wellbore in this one of these 40-acre tracts that's currently already drilled and --

Q. If you have a dryhole, maybe you've condemned it, huh?

A. You've condemned it in that dryhole. But maybe not -- You haven't condemned the rest of the 40.

But that's the point: You can have a multiple of conditions out there, and you have to address those contractually before you come to the Division for a request for a horizontal wellbore.

Q. Well, I guess my point -- I was getting more at the complexity of trying to address something administratively when there's still the avenue for a hearing when you have a correlative-rights issue. I mean, aren't we saying that these applications can still go to hearing if they vary from the norm?

A. Certainly.

Q. And I visualize this idea -- And item number 3 may work fine in the San Juan Basin.

But other issues in the Permian Basin can be a lot different when you're dealing with smaller spacing units --

A. Yes, sir.

Q. -- when you're dealing with competition, we'll say, within the reservoir for oil with offset operators, and therefore the allowable can be a significant factor?

A. It certainly can, and that's the whole reason, the whole rationale behind notifying offset people.

Q. Yeah.

A. And you would notify the people in this 320 when you proposed it for the internal owners.

So you've got both classifications of people notified --

Q. Uh-huh.

A. -- and they have the full right to come and protest it, in which case I'm assuming the Division would set it for hearing --

Q. Yeah.

A. -- and explore any of those particular peculiar matters that may impact this particular project.

Q. Yeah, generally we allow for administrative approval for the common case.

My point is, even at Division discretion, there's a lot of cases that don't fit the common case, where there may -- there have to be a designed order to fit -- especially the correlative-rights issues.

A. Yes, sir.

Q. And another example -- and I bring this up only because it's happened and may not be able to be addressed within a rule, but your Exhibit Number 7 whereby -- I think you testified that it would not be administratively approvable, in your recommendation, to perforate outside of the window within the proration unit that's allowed?

A. That's correct.

Q. In other words, to encroach on an offset operator?

A. That's correct.
Q. For a moment -- Have you had Permian Basin experience?
A. Very little.
Q. Okay. Well, in the Permian Basin we do have some Pinnacle Fusselman fields. If you were going to try and directly drill -- encounter the productive acreage, maybe a very small 10- or 20-acre target down there, and maybe you miscalculate on your seismic and you come up with the only productive interval in that wellbore is outside the drilling window that you're allowed to produce in, but you still have it on your acreage.
A. Yes, sir.
Q. It's been experience, common practice for the operator with a rig on location to call me and say, Hey, I've got this deviated wellbore with some productive -- I've got some productive Devonian, some productive Fusselman. It's outside of the window, but it's under my acreage. Can I complete that well at my own risk and expense? Otherwise I've got to move the rig off, move it back on, and therefore come to hearing for an allowable.
A. Yes, sir, I understand that.
Q. You understand that?
A. Yes, sir.
Q. The situation?

A. Yes, sir.

Q. You're not going to address that with this rule?

A. No, sir.

Q. That would be something that would be at the discretion of the Director?

A. That's correct, this rule does not address those situations.

Q. Okay. I bring that up only to say that's common practice, and it's prudent, once you have a rig on location, to generally do what you need do while that rig is there, recognizing that you can have a correlative-rights issue once you perforate, move off, et cetera.

A. Yes, sir, we are not proposing that for an administrative application.

CHAIRMAN LEMAY: All right. I have no additional questions.

Any other questions of the witness?

If not, he may be excused.

And let's take about a 15-minute break and come back for Marathon.

(Thereupon, a recess was taken at 10:43 a.m.)

(The following proceedings had at 11:07 a.m.)

CHAIRMAN LEMAY: We shall continue.

I think Mr. Campbell, with Marathon --

MR. CAMPBELL: Yes --

CHAIRMAN LEMAY: -- are you ready?

MR. CAMPBELL: That's correct.

My name is Dow Campbell. I'm an attorney with Marathon Oil Company out of the Midland, Texas, office, and we're here in support of Meridian's Application and here to offer a few additional recommendations to their proposals.

And we have one witness today, Mr. Dick Pollard.

CHAIRMAN LEMAY: Okay.

RICHARD E. POLLARD,

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

DIRECT EXAMINATION

BY MR. CAMPBELL:

Q. Please state our name, employer and occupation for the record.

A. My name is Richard Pollard. I work for Marathon Oil Company in Midland, Texas, and I'm an advanced senior petroleum engineer.

Q. Mr. Pollard, have you testified before the New Mexico Oil Conservation Commission on any prior occasion?

A. No, I have not.

Q. Okay, please summarize for us your educational background as well as your work experience.

A. I graduated from Marietta College in 1969 with a bachelor of science degree in petroleum engineering.

Following graduation, I spent three years in the United States Army as a petroleum lab specialist.

Following discharge from the Army, I hired on with Getty Oil Company, worked as a petroleum engineer for approximately three years before hiring on with Marathon Oil company, and have worked for Marathon Oil Company continuously for the last 20 years in various capacities, including production, reservoir engineering and government-compliance work.

Q. Okay. Is it part of your current duties to review proposed rules and regulations for Marathon of the OCD in New Mexico?

A. Yes, it is.

Q. Okay. Pursuant to those duties, have you reviewed Marathon's proposed rule for administrative approval of horizontal, high-angle and directional wells?

A. Yes, I have.

Q. Okay, have you actively participated in any of Marathon's Oil Conservation Division hearings regarding horizontal wells?

A. Yes, I recently testified in the OCD horizontal hearing as an expert reservoir engineer in our Denton application.

Q. Okay, based on your studies and experience with Denton, do you have any recommendations to the Commission regarding the proposed rule?

A. Yes, I do.

MR. CAMPBELL: Mr. Chairman, I tender Mr. Pollard as an expert engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Campbell) Before we elaborate on your specific recommendations, let's review for everyone's benefit Marathon's history of horizontal wells in New Mexico, and it might be best to begin with Exhibit Number 1. Please identify that for everyone present.

A. Exhibit Number 1 shows Marathon's operation in the Denton Devonian lease in Lea County, New Mexico.

The yellow area represents our lease holdings, approximately 280 acres.

Our first proposal before the hearing was in March of 1994, for application for a horizontal project area.

Q. Why do you think it's beneficial to summarize Marathon's experience in the Denton field?

A. I feel that this example illustrates the need for administrative approval of directional or horizontal wells, when no correlative rights are being violated.

Q. As opposed to Meridian's example, this is an oil field, correct?

A. That is correct, this is a Devonian oil field developed on 40 acres.

Q. And does the highlighted area have a common ownership?

A. Yes, it does.

Q. Okay, what does the dashed line represent on that highlighted area?

A. The dashed line represents the 330-foot standoff line which is the standoff requirements for this field.

Q. Okay. How many times has Marathon testified before the OCD seeking approval for directionally drilled wells within the Denton field?

A. We've appeared three times, first time being in March of 1994.

Q. Okay. Can you summarize for us what Marathon was requesting in those three hearings?

A. In March, 1994, Marathon was requesting horizontal project area, as shown in yellow on this exhibit.

Initial well that we requested was Well Number 5.

Q. Okay. What was the outcome of that hearing?

A. We were granted approval to only drill the Number 5 well in the northeast direction, as shown on this exhibit in red.

Q. Okay. Did Marathon subsequently directionally drill the Number 5 well?

A. No, we did not. The Well Number 4, which we consider to be structurally higher than the Well Number 5, is a better candidate for horizontal drilling.

However, at the time of the hearing Well Number 4 was still commercial, whereas Number 5 had been shut in for many years. So we elected to ask for Number 5 first.

In the interim, Number 4 production had dropped off to where the well was no longer commercial, and thus a better candidate for horizontal drilling.

Q. Okay. What did Marathon -- What was granted by the Division out of our second hearing?

A. In November -- In our second hearing, Marathon asked that we be granted the horizontal Well Number 4, as well as Number 6, both shown on this exhibit. We were granted permission to drill horizontally out of both wellbores.

Q. Okay. Was either the Number 4 or the Number 6 ever directionally drilled?

A. The Number 4 well was drilled and completed in February, 1995, and production reached a maximum of 499 barrels of oil per day. The well is currently producing over 150 barrels of oil a day.

Well Number 6 has not been sidetracked as of this date.

Q. Okay. Please tell us the purpose of our request for a third hearing.

A. Based on the success of the Number 4 well, Marathon felt that the Number 5 well was now our second best candidate for horizontal work, so we reapplied to the Commission to sidetrack the Number 5 well.

Q. Okay, let's turn to Exhibit 2. Please identify Exhibit 2 for the Commission and tell us what it depicts.

A. Exhibit 2 shows a cross-section from the Number 5 well to the Number 4 well. And as can be seen on the bottom left-hand corner, the cross-section cuts through the Number 5 well and cuts through the intersection of the horizontal in the Number 4 well.

The orange cross-section area is the tight cap of the Devonian, or can be considered the top of the Devonian.

As can be seen, the Number 5 well is programmed to be drilled horizontally, basically parallelling the tight cap and going updip towards the Number 4 well.

The little dot, "horizontal wellbore", basically underneath the Marathon Denton Number 4 well, is the horizontal section of the Number 4 well. If you can think of it, the well's horizontal section is coming out of the paper at you, and that's where it would be in relationship to our proposed Number 5.

Q. Okay, what's the current status of our hearing on the -- our third hearing on the Denton field?

A. We are currently waiting on determination.

Q. Okay. To recap, Marathon's had to testify three times before the OCD seeking approval for directional wells on this 280-odd-acre lease.

Have you estimated what it's cost Marathon for the hearing process?

A. Based on my inquiries, Marathon has expended over four man-months preparing for these three hearings.

Q. Okay. Do you have any idea what the OCD has been -- has incurred?

A. In addition to the expenditure by Marathon for geologic, drilling engineer, reservoir engineer and associated people and the travel expenses, the OCD had to prepare, conduct and issue orders on three separate occasions on this one project.

Q. Okay. Keeping in mind Marathon's experiences regarding the Denton field, let's turn to what we have labeled Exhibit 3. Please identify this exhibit.

A. Exhibit 3 is a proposed regulation by Meridian, as attached to the original application.

Q. Okay. Please summarize what's on this exhibit that Marathon is not requesting be changed.

A. Let me go back to the exhibit one time, just to make it a little clearer. On this exhibit shows the original wording. Marathon has struck through the words we would propose to be deleted, and we have underlined the wording that we propose to be added on it.

Q. Just to clarify the point, this is a red-line version of their original proposal. We had not seen that revised proposal until today.

Again, please summarize what we were not expecting to change, what we were not proposing changes.

A. Marathon fully supports Meridian's effort to allow administrative approval of directional wells. Marathon concurs that the correlative rights of the offset operators should be protected.

We also agree that adequate notification be provided to owners of offset leases. We support the Division's right to retain the discretion to call a hearing when needed.

Q. Since several changes are noted on this exhibit, please summarize the three general categories of modifications which Marathon is recommending to the Commission.

A. First, we are requesting that many of the definitions be removed or simplified.

Second, the amount of information requested should be substantially reduced.

And third, we're requesting we simplify the allowable procedure for directional wells in project areas.

Q. Okay. Without reviewing the proposal entirely, line by line, please state which definitions you're suggesting should be deleted and why you're suggesting that.

A. This proposal was originally presented as well definitions for horizontal wells, high-angle wells and directional wells.

Beyond the definitions, there is no difference or differentiation in the treatment between the three types of wells.

For simplicity's sake, we recommend that only one type of well be defined. That is a directional drill well, which is defined as a well intentionally deviated from the vertical, as Meridian has defined it.

Q. Okay. Do you have any additional definitions that you feel should be deleted? And if so, why?

A. Yes, the definition of ultrashort-, short-, medium-, and long-radius laterals should be removed. Again, there is no distinction or reference made elsewhere in the regulations which warrant these definitions.

It is also my belief that the industry has not standardized on these definitions, and due to the high technology being used and continued development in this technology, the definitions may be outmoded before they're actually put in print.

Q. Is that all your recommendations regarding deviations, other than minor --

A. Yes.

Q. -- typographical changes?

A. Yes, it is.

Q. Okay. You mentioned a second category of modifications as the reduction in the amount of information which is required under this rule.

Please summarize your recommendations regarding that topic.

A. Will you repeat the question, please?

Q. Sure. You talked about the three general categories. The first was refining and deleting definitions, and secondly restricting the amount of information that is required pursuant to this rule to be filed with the administrative application. Please summarize your recommendation as to that category of modifications.

A. It is Marathon's intention in our proposal of changes to reduce the burden on both the applicant as well as the OCD by limiting the required information to that which is required or -- which is not required, excuse me, or provided under other rules or forms or is not needed at the time of application to grant the approval.

Basically, we feel a lot of this information is required and submitted on other forms.

Q. Okay. Can you give us some examples of what you're calling unnecessary or duplicate information?

A. Yes, in Section C, Number (1), as originally proposed by Meridian, require nine-section plat. We feel this is overkill. A plat similar to what we submitted as Exhibit 1, we feel, is more appropriate.

Q. And that's especially in the smaller --

A. Smaller oil-development areas.

Q. -- 40-acre proration units, et cetera, for oilfield.

Okay. Any further examples?

A. And C (2) requires the well be produced by characterization, projected by characterization.

Because we are moving the definitions, that no longer applies, and that requirement does not need to be in the rules, if you remove the definition of high-angle, short-angle-radius wells.

Number (6), a written summary of drilling, casing and completion programs is required. We feel it's not needed, and I believe Meridian has already struck that proposal. That's Number 6.

Number 7, likewise, we feel, is not needed. That refers to the plugging and abandonment procedure being provided in the Application. As Meridian stated, we feel that is provided in other documentation, prior to plugging the well, thus not being needed.

Number 10 also requires a copy of the approved AFE. I believe Meridian has struck this already.

We feel the AFE contains proprietary information and should not be provided and become public record.

Most JOAs provide for nonconsenting parties. An applicant should not be denied if they're not 100-percent approved, as they can be taken care of, as mentioned, by contractual arrangements.

Nonconsenting parties has, of course, recourse to a hearing if they have a problem.

Q. Okay, that summarizes your changes to -- What? Section C of the proposed rule; is that correct?

A. Yes.

Q. Okay, let's turn to the allowables issue, which you referenced as the third of the three general categories of modification.

What is Marathon's recommendation regarding allowables?

A. Marathon proposes to simplify the application process by adopting the concept of shared allowables for routine administrative approval of horizontal wells.

The concept provides for a single project allowable whereby production can be from any -- or any combination of wells within the project area.

This concept was presented during our three hearings on the Denton project, and I believe it was well received.

Q. Do you have any other recommendations regarding the proposed rule?

A. No, I don't.

MR. CAMPBELL: Okay, this concludes my examination of Mr. Pollard, Mr. Chairman.

I move for the introduction of our Exhibits 1, 2 and 3.

CHAIRMAN LEMAY: Without objection, Exhibits 1 through 3 will be admitted into the record.

Questions of the witness?

Commissioner Weiss?

COMMISSIONER WEISS: Yes, I have a couple.

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, concerning -- You were here and heard Mr. Alexander talk about allowables?

A. Yes, I did.

Q. He proposes two kinds of setback as being the -- at least -- I can't understand what he wrote, but I think that's what that says, wellbore radius equal to two times.

A. Yes.

Q. And I looked at your plat here in Exhibit 1. Number 6 would violate that. If you had two kinds of wellbore radius there, you would be over on the unleased or the other operator's acreage there.

I guess it would work in the case of Well Number 5, it would be pretty close.

A. Yes. Well, what Marathon would be asking for in the case of Number 6, that we would have the allowable of Number 6 and Number 7, and we would be able to share that allowable or produce that allowable either out of Number 6 or out of Number 7 or both.

Q. I understand what you're proposing. I'm just --

A. Okay.

Q. -- thinking through what he had proposed and how that would affect you if that should happen.

And I guess that wouldn't work here because Number 6, if you had two times the setback distance there, you'd be over on the acreage there that's not included in your project areas --

A. Yes.

Q. -- is that right?

A. That's correct.

Q. So that wouldn't work there.

Could -- If that were the rule, could you use

Number 7 and drill south?

A. For the benefit of increasing allowable purposes?

Q. Well, to avoid the problem of -- If two times the setback were the apparent wellbore radius, two times the setback distance was the apparent wellbore radius, perhaps you wouldn't be allowed to drill Number 6 because you would be effectively interfering with the acreage there that's not in your project area. But if you drilled from 7, you wouldn't be; is that correct?

A. I believe that would be correct.

COMMISSIONER WEISS: All right. Just a comment. I was just looking at this.

That's all the questions I have. Thank you.

CHAIRMAN LEMAY: Commissioner Carlson?

EXAMINATION

BY COMMISSIONER CARLSON:

Q. In your three hearings for horizontal wells, was there any opposition to Marathon's proposals?

A. As far as I know -- I only attended the last one, which there was not, and I believe there was no opposition in the first two either.

MR. CAMPBELL: No, there was not, there was no opposition.

COMMISSIONER CARLSON: I guess I have a question of Mr. Kellahin.

How strongly does Meridian feel about Marathon's rewrite of your proposed rule? Could you live with the changes they recommend?

MR. KELLAHIN: I'm not sure I know the answer yet, Mr. Carlson. Let me think about it, and may I respond later?

CHAIRMAN LEMAY: I think we'll have, before this is over, some pretty general discussion as to -- I'd like to set a couple parameters to maybe some submittals at the end.

But that's a good question. Let's put that on hold just for the time being.

MR. CAMPBELL: Likewise, Marathon did not see their proposed change till today either, so we're --

CHAIRMAN LEMAY: Yeah, I understand that.

MR. CAMPBELL: -- we're not sure how they apply to every situation we have either.

COMMISSIONER CARLSON: All right. That's all I had.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Okay. But Mr. Pollard, what you're saying basically is, you -- It's a project allowable, you're describing a project allowable as one in which if the directionally deviated well crosses any portion of a proration unit, you add that proration unit's allowable into the total allowable of the well?

A. That is correct.

Q. When you're getting into existing wells -- I noticed your proposal also allowed for dividing up the allowable in any proportion that the operator chose, if there was more than one well on an existing proration unit?

A. That's correct.

Q. I guess I could visualize a situation where if you get in competition in the reservoir, if you had a well very close to an offset operator, that you might pull that one a little harder than another well, a vertical or --

A. Well, in all cases we would be within the standoff area allowed by field rules, in this case 330 feet.

Q. And you're not limiting the number of wells within a proration unit; the only limitation would be one of allowable; is that right?

A. That is correct.

CHAIRMAN LEMAY: Okay.

COMMISSIONER WEISS: I have one more question.

CHAIRMAN LEMAY: Yeah, Commissioner Weiss.

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Does the engineering and geology influence the direction of these wells more than the allowable situation? Or which --

A. In our particular case, yes, we are trying to get structure and trying to cross fractured areas that have not been drained.

Q. I guess you're saying that that could vary by situation though, it's not -- This may be unique to this reservoir here?

A. The allowable is high enough that even a horizontal well cannot produce even one proration unit's worth allowable.

What we could foresee and we could hope, that some day we could find a case that we would need that extra allowable.

COMMISSIONER WEISS: Okay, thank you.

CHAIRMAN LEMAY: Any other questions of the witness?

MR. CARROLL: Yes, Mr. Chairman, I have one question.

CHAIRMAN LEMAY: Mr. Carroll?

EXAMINATION

BY MR. CARROLL:

Q. The same question I asked Meridian.

Is it Marathon's proposal to allow the OCD to administratively approve the change or alteration of setbacks?

A. No, it is not our intention to alter the setbacks administratively.

Q. And why is that?

A. We feel that should be in a hearing.

Q. And why should it be in a hearing?

A. Because it involves the rights of offset operators.

MR. CARROLL: That's all I have, Mr. Chairman.

CHAIRMAN LEMAY: Okay. Additional questions of the witness?

If not, you may be excused. Thank you very much, Mr. Pollard.

Mr. Carroll, do you plan to put on a witness or --

MR. CARROLL: Yes, I do.

CHAIRMAN LEMAY: Okay.

MICHAEL E. STOGNER,

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

DIRECT EXAMINATION

BY MR. CARROLL:

Q. Mr. Stogner, will you please state your name and your place of residence for the record?

A. My name is Michael Stogner. I'm a petroleum engineer with the Oil Conservation Division here in Santa Fe, and I reside in Estancia, New Mexico.

Q. And is it part of your duties as a petroleum engineer for the OCD to review and consider applications for directional drilling?

A. Yes, it is.

Q. On prior occasions, have you had an opportunity to testify before this Commission?

A. Yes, I have.

Q. And have your qualifications as a petroleum engineer been accepted?

A. I believe so, yes.

MR. CARROLL: Mr. Chairman, I offer Mr. Stogner as a petroleum engineer and ask that his qualifications be accepted.

CHAIRMAN LEMAY: They're accepted.

Q. (By Mr. Carroll) Mr. Stogner, you've heard the testimony given prior to yours. What specific comments or recommendations do you have concerning what you've already heard?

A. Essentially maybe a historical retrospect to the Commission's and Division's involvement with horizontal drainholes over the years, and perhaps some additional thoughts for the Commission to consider in adapting rules and regulations for administrative procedures, how we've gotten to this point, perhaps some other pools that already have pool rules that provide for administrative procedures, perhaps another way to look at allowable proceedings, bring up some scenarios and some further exceptions that might prove helpful in the Commission making its decision.

Q. Okay. I'll ask you to look at what has been marked as OCD Exhibit Number 1.

A. Exhibit Number 1 is just a scenario, and which we have seen in the past, perhaps not exact, but what I've tried to depict here would be similar to a situation that Petroleum Development, which is Mr. Jim Johnson out of Albuquerque's company, what they have been doing down in the Chaveroo area in Chaves and Roosevelt County in the Tom Tom-San Andres Pool and down in that area.

And what we have done in that particular area, he has developed leases with horizontal wells, he's had producing wells, vertical wells, old plugged and abandoned wells, vertical, and then he has come in and perhaps drilled a horizontal, decided to change the technology a little bit different in another one and take off.

There in this particular area, the geology or the direction of the drainhole -- and I'm deviating from the terminology here because that's what I'm used to -- the horizontal portion or drainhole is not dependent on geology. So we have had scenarios in there where horizontals would take off in different directions. Food for thought. A project allowable.

And we have provided in those orders, signed by Mr. LeMay and -- whereby the district supervisor could perhaps assign a project allowable when this scenario occurs.

And if you look here, in this particular scenario, I've got three vertical wells producing, three horizontal wells producing. The three horizontal wells go in all different directions.

We have a similar scenario whenever we have a waterflood, we have a project allowable where we take the number of 40-acre tracts attributing production in the lease or project unit, whatever -- in this particular case the project or the lease -- times the depth bracket allowable. This then would become the project allowable.

And then within that project allowable -- With that project allowable being assigned, then all the wells can produce that allowable in any proportion.

Just food for thought, perhaps an easier scenario. That way we wouldn't have -- Well, in this particular instance, we would have two 40-acre tracts attributed to the same well.

It becomes almost impossible in this instance that you would have a proration unit per se. Just something to consider, allowing either the district supervisor or perhaps in the administrative process setting the allowable.

That's all I have on Exhibit 1.

Q. Mr. Stogner, do you have any recommendations as to the definitions proposed by Meridian and the deletion of certain definitions proposed by Marathon?

A. Well, personally I like the definitions. Here in the regulatory realm, we always have inquiries about how many horizontal wells have been drilled, how many of them have been long-radius, short-radius, whatever the case may be.

In that particular aspect, for statistical purposes, it may not be a bad idea.

Also, I think, if we had them in there, perhaps if we revisited whatever rule comes out of the Commission today, in our general rules, revisit it in two or three years to see if it is doing an adequate job, to see if it needs to be changed, to see if it needs a new direction.

That's something that we normally don't do with our general rules and regulations, is revisit them, not like we do special rules and regulations in a pool. Perhaps we may want to do that.

There again, I like the concept of the definitions, and the reasons I think definitions earlier on were important to us is because to get to this point I believe we were trying to, early on, develop pool rules to allow for what kind of directional drilling or horizontal work best in that pool, and that's the reason we came up with that.

But I personally like the definitions.

Q. Mr. Stogner, have you had the opportunity to review Meridian's original proposed rule included with their application and then their proposal to delete certain of the information required under that proposed rule and then Marathon's proposed deletions of information be filed with the Division?

A. Yes, I do.

Q. Do you have any recommendations as to what information should be required?

A. As far as recommendations, no, not at this point. I'd just like to offer some comments, perhaps, or some insight on perhaps some amendments to these rules or even additions that the Commission might want to consider.

Q. Now, are you prepared to offer your insight at this time?

A. Yes, I am, basically.

Q. Will you tell us what you recommend?

A. I really didn't have anything prepared today, inasmuch as I wanted to see what the industry would come up with and see where they were going. Perhaps some of my ideas would be covered by some of the others, perhaps in the closing arguments and closing statements.

As far as a historical retrospect, if I could, this is not the only case. In 1955, Case Number 942 came out, the Conoco-Continental Oil Company, to provide for a short-radius horizontal drilling technology in those days. That case was essentially dismissed due to lack of interest.

And then in 1979 -- or late Seventies, early Eighties -- Arco, down in the Empire Abo, started drilling short-radius horizontal drainholes.

At the same time, Harlan Drilling, which was essentially a spinoff of the Texas Eastern group, at the same time was drilling horizontal wells up in the Gallup formation, up in the northwest. I was heavily involved with that one.

And that was essentially the extent of the horizontal drilling in the early days, and more -- that was more so to develop the tools and techniques.

In 19- -- about 1985, 1986, El Aquitaine [phonetic] wanted to do their great American adventure as far as horizontal drilling, and they were at that time foremost in the horizontal technology. They came out to New Mexico and wanted to extend into the fractured zone of the Mancos formation and intercept different fractures.

After that, Meridian, Amoco, Yates, Petroleum Development, many others, American Hunter, Veteran Exploration, Merrion, Benson Montin and Greer, for various reasons came into different pools and tried to develop horizontal techniques.

Some of the pools that we have -- There's three of them that have special rules. The Basin Fruitland Coal Pool has an administrative procedure for horizontal drilling, and that's in Order R-8769, I believe. The Rio Puerco that Veterans is developing are one of their offshoots. They change names all the time, and I can't keep up on it.

Up in the northwest there's some procedures administrative in that particular pool, and of course the old Empire Abo, which I've recommended to the Director three approvals within the last several months. They wanted to get active again in the Empire Abo.

Some of the comments I've heard with respect to general rules and regulations over the years -- It was our idea in the beginning, or at least we tended that way, was to promulgate rules for different pools, whatever worked, if a short radius worked in one particular pool, or the long, far-extending method in the other, then we would develop it toward that, to its unique problems, such as ownership, if we had 40-acre spacing, versus 640.

I've got two 640-acre proration units that Benson Montin and Greer -- so I've got one -- no, I think I've got two 1280-acre proration units in the state because of the horizontal well. And that's how that got started, or at least that's where we were going.

And I believe now we have had enough experience -- and I know this question has been asked several times. I can't really think of any time where the actual horizontal well has been objected to. There has been objections to, say, an increased allowable or getting close to a lease line. But I -- As far as the actual horizontal, I don't recall any time when that was the cause of the objection.

We've seen many instances in this state where an operator has wanted to push that window of opportunity, if you will, past the regular setback requirements.

Merrion is a good example. In their particular instance, they were trying to avoid water coning when a high-porosity -- how would you say? -- windblown-sand-dune-type formation, substructure formation, where they were trying to get the horizontal well on the crest of the buried sand dune. And in this instance they formed units.

But however, the geology called for them to -- and in this particular instance, skirt within 10 feet of the lease line.

It was thrown out. Everybody had an opportunity to come in and object, nobody did. In this case, geology called for it, nobody objected, they had the opportunity to, and it was approved. It just made the window of opportunity.

And that was one of the things I think this state -- somewhat unique, is the window concept, as opposed to looking at a drainhole or a horizontal. Let's open it up to the window, because you don't know exactly what direction -- In some instances, like Meridian's case, where are we going, actually, when we get down there? Or, if you start drilling and you have a problem, you can pull back, get started again. Or drill multiple drainholes or horizontals.

So we came in with the window concept. I learned this lesson the hard way when I was in Alabama and I watched a supervisor of mine stand up in the commission on a 330-acre spacing -- I'm sorry, 40-acre spacing, 330 offset; the well was at 330-330 -- and we were going to drill a 500-foot horizontal or lateral.

And in those days we had no direction control. The only direction control we had is watching the pipe go down in the direction in which we screwed the directional device in. Those were the days. And they said, Oh, of course we can control the deviation.

Of course we can now, there's no doubt about it. But to what degree of excellence do you want? Sure, you can put it on a dime if you want to, but that's going to be adding cost.

So that's the reason -- and I'm glad that Meridian and everybody else has adopted this window concept. I think in the long run it's economical for them, it's -- it puts less burden on us and our district people to be able to go in.

But I think there ought to be an administrative procedure in which we can push the setback requirements for geological purposes.

We're also looking at, in the next few months, more geological exceptions at unorthodox locations. This, of course, goes hand in hand.

One of the reasons most of these cases go to hearing in the first place is because they took exceptions to several different things. Not only directional drilling. You had to set up a nonstandard proration unit usually, because the lateral extended beyond the proration unit limit. Usually an unorthodox location was involved, whether the surface location, like in Meridian's example on page 6 -- or Exhibit 6, I should say -- showed.

Also, a lot of them wanted an increased

allowable. Well, that kind of comes hand in hand with the formation of a nonstandard proration unit, especially if you have two 40-acres or whatever the case may be, you just doubled it.

But in some instances, many parties -- I can't remember, some company out of Odessa, I believe, wanted an increased allowable, beyond the normal acreage factor. I think that ought to be considered for an administrative process. And then that way, because of the notification, if anybody had a problem, we could take it to hearing.

Also, it has been brought -- some instances, perhaps -- and I refer now to Meridian's Exhibit Number 6. In this particular scenario, their producing portion of the well is within the setback requirements for the proration unit in this pool.

And in this particular instance, why -- or perhaps some of the companies have indicated -- In this particular instance, why go with an administrative process? Why not let the APD and the district's approval be the final say in this one, in this particular instance like this?

And then once the well is drilled and a directional survey is done, and then is shown that the actual producing portion is well within the setback requirements, then an allowable can be signed off or approved at the district level.

That is some of the comments I've heard, perhaps, and I just bring that up for the Commission to consider, because I know as far as -- You heard testimony on Meridian and Marathon today. They did not mention that, nor both of them talked about not being able to extend the setback requirements administratively.

That's all I have.

Q. Mr. Stogner, did I hear you right? You're recommending that the OCD be allowed to administratively approve the expansion of windows through altering the setbacks?

A. Yes, I do. And yes, I am.

MR. CARROLL: Mr. Chairman, that's all I have of this witness, and I'll move what has been marked as OCD Exhibit Number 1 into the record.

CHAIRMAN LEMAY: Without objection, OCD Exhibit 1 into the record.

Questions of the witness?

Commissioner Weiss?

COMMISSIONER WEISS: I don't have any questions.

CHAIRMAN LEMAY: Commissioner Carlson?

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Stogner, I just had one. Just as an example, on your example here --

A. Yes.

Q. -- what happened -- or how would you feel if -- we'll say the -- on a project allowable, if the two wells there were extremely marginal, we'll say a barrel a day -- The two wells I'm speaking to are in the extreme northeast portion of the map and the extreme southeast, the two 40-acre locations that the horizontal wells have not penetrated.

Based on your example, I think you would be recommending an allowable of 8 times 80, or 640 barrels of oil per day for the project, where possibly under the -- if a project allowable was defined as only those proration units penetrated by horizontal wells, you would take maybe 6 times 40 and have 240 barrels of oil per day allowable assigned to the project, because two of those 40s, at least under one recommendation, would not qualify to be added onto the allowable?

A. I think whatever fit the picture. I think we'd have enough flexibility that we could do either.

In this particular instance, let's say all six of these wells were marginal to begin with. And how many proration units do we have? Six wells, eight proration units.

In the vertical concepts you'd have the six wells, six 40-acre proration units, each developing on an allowable.

Now, if we extended that project allowable concept just to those vertical wells, and according to our waterflood, if you want to take a look at it, then perhaps you can take those two proration units that didn't have a well -- I'm talking about the vertical concept here -- take the allowable that would be attributed to those out, because they're not attributing any production.

Q. Right.

A. Now, in this particular scenario, all eight proration units would be brought into the picture, because each of them are attributing production, either through the vertical wells, like the one in the northeast and the southeast corner, and then you've got two of the nonproducing or previously nonproducing 40-acre tracts now being criss-crossed by horizontal wells.

Now, to answer your question, as far as taking -- perhaps omitting the margin allowable of those two vertical wells and then just going with the six proration units that have horizontal wells, I think our -- or what I would propose is that we would have enough flexibility within the project allowable to have six of the 40-acre project allowable proration units, and then those four wells in this instance attributing production, and then take the two

40-acre tracts that's not "participating horizontals", put those out on their own as minimum or marginal allowable.

But for ease of administration -- administrative ease, I should say -- of assigning allowables in the computer, if all the wells are allowable then let's go with all six wells attributing to the eight proration units.

I hope that answers your question.

Q. So would you go with this case, 240 barrels a day or --

A. I would, yeah.

Q. I mean, you take the six and not the eight?

A. No, I would take the eight.

Q. You would take the eight?

A. Uh-huh.

CHAIRMAN LEMAY: Commissioner Weiss, do you have --

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, following up on that a little bit.

What if it was the project was the entire section here? Then it would 16 times 40, would be the allowable?

A. Not necessarily, because that would be the project. But I think -- When we get to a point where we assign a project allowable of some kind, we would have to have a scenario such as this, perhaps, through a large portion of the lease.

Q. And then it gets complex again?

A. Oh, yeah, it gets complex again. But I think that we have enough expertise in our district offices, and hopefully in our new ONGARD system, to take care of it.

Q. The idea is to make it easy, maybe the wellbore radius thing and the setback limit is -- maybe not two, but one or half or something of that nature?

A. Wellbore radius.

Q. Meridian's idea of effective -- I think that's what they said that I can't understand.

But the picture on page -- Exhibit Number 8 in their book, where they discuss the -- They've got the perpendicular lines to the lateral, and if a person -- and those are supposed to be the setback distances.

If you just thought about that as the -- That explains what the verbiage says over there a few page earlier, quite well. Pictures are certainly worth a thousand words here.

But if a person did go to school on that and used the setback distance, some ratio of it, perhaps, as effective wellbore radius, then you could say, well, it contacts whatever and -- whatever proration units there are.

A. Maybe, perhaps, to answer your questions, let's say the project was the whole section, but you assign the project allowable to only those 40-acre tracts that are attributing production to the lease.

Q. Well, they all are maybe. And then you've got to have a reservoir study or something. So that's what --

A. Okay, let me rephrase that. How about effectively participating in the project?

Q. Yeah.

A. And effectively in this instance is that we have a well touching the 40-acre tract.

Q. Well, that's what Marathon proposes, of course

But I can see the point of -- you know, your well goes right by one of these units, and it's certainly draining from it, so it should be included in the allowable.

A. I think we could have enough flexibility, especially if it's one lease.

Q. And then you could have it -- If you had it as a function of the wellbore radius, and that is a function of the setback limit, you could do that. It would catch them all that are -- that you have in your project.

A. If the geology and the radius -- or, I'm sorry, if the geology and the drainage qualified it as such.

Q. Maybe two is too much. Maybe a half or one or something.

A. Just another way to calculate the project -- or an allowable -- in a scenario such as this. It's just what I'm offering at this point.

COMMISSIONER WEISS: I have no other questions. Thanks.

CHAIRMAN LEMAY: Any other questions of the witness?

If not, he may be excused.

I think what we'll do at this point is take the statements that you all -- because I think we want to hear how the rest of you feel about the testimony that's been received to date.

And then I'd like to have a little bit of an informal discussion. I know normally it's not been our policy to take statements and subject to cross-examination. Please don't interpret our questions as Commissioners to be cross-examination. What we're trying to do is find a consensus out there as to what may be the best draft order. So we're going to vary procedure a little bit from norm and follow that.

So with that, I think Mr. Hawkins, you want to make a statement in regard to Amoco's position?

When you make your statements, it would be helpful to us, too, to say, Hey, I support Meridian's, or I support Meridian's with the variations that Marathon put on it.

MR. HAWKINS: Okay, I'm Bill Hawkins with Amoco, petroleum Engineer. I've testified before the Division on a number of occasions, and in fact in horizontal well applications for Amoco I've been here on eight horizontal wells.

We've looked at the Application that Meridian has put forth, and we've looked at the revisions that they've presented today, and also those of Marathon.

And the first thing I want to say is, I want to commend Marathon [*sic*] for putting forth all this effort to gather the comments and bring this Application to the Commission.

We're going to be planning to drill five horizontal wells in 1995 and, if those are successful, extend that program into 1996. So we hope to be able to use the administrative process.

Amoco does support the recommendations that have been made, in general, by Meridian, and also some of the recommendations made by Marathon.

I think our concept here is to put some administrative rules into place that would accommodate the approval of, let's say, 80 percent or so of the horizontal wells that you might see as an application in the State, those that are normal, that stay within a -- you know, basic setback requirements, that don't require -- don't ask for any special exceptions for location or special complex approval of allowable. We think those should certainly be able to be approved administratively.

The -- I guess if we just go through the document that Marathon -- or excuse me, that Meridian put forth, the first question that we saw was the definitions for the radius and how you categorize the type of horizontal well that's to be drilled.

I guess the -- We don't have problem with categorization of those type of wells. The concern we've got is, what's the use for that? If we think the State needs to develop some kind of statistics, then certainly that categorization would be helpful.

Other than that, I think we wouldn't really need the categorization, because we will be able to give the details of each horizontal to you in the Application. What's the rate of build, what's the radius of curvature, and then what's the extent of the lateral?

So we could probably get by with the Marathon proposal to eliminate that, unless the State feels like there's a need to categorize and keep some kind of statistics on it.

The other recommendations that I've seen are generally to delete some of the requirements that were in the first proposal that was submitted, and I think Amoco would support that. We think that even as far as the deletions that Marathon has commented on, that those would be appropriate.

And specifically I think I'd like to point out that under -- Let's see, which section this is. Under Section C on -- to obtain administrative approval, items (5), (6), (7), (8), (9) and (10) are all requested to be deleted by Marathon, some of those also requested to be deleted by Meridian.

Amoco would support the deletion of all five of those, or -- I guess six of those -- those six items, particularly for the administrative process. If we get into a hearing and there's some protest involved or a special, complex case, then maybe we need to draw that out and obviously explain a little bit further what we're trying to do.

But for a simple horizontal well all contained within a single spacing unit or some simple -- a few 40s that are joined together, I think we wouldn't need to supply the type log and the information on how the well is going to be drilled and completed and how -- why we, you know, think we need to drill this horizontal well in this area, what's the engineering and geologic purpose for that?

So I think the key is to try to develop some administrative rules that are going to be simple for us to follow and file a relatively simple amount of information with the Division that can be approved.

The last thing that I guess I wanted to comment on specifically was the -- on the allowable, I know in the northwest pools, in the Blanco-Mesaverde Pool where we've been doing a lot of our horizontal wells, there are already existing wells in that pool. In some cases the horizontal well may be the third well, or it may be the second well or re-entry of a second well and extending that in a horizontal fashion.

The allowables in those cases have typically been set on a deliverability from two of the wells in that spacing unit and been able to produce the calculated allowable by all three of the wells, so long as we didn't exceed that allowable. And Amoco would support the continuation of that type of an allowable approach.

The last thing I guess I have to say is that we support the recommendations that we notify the offset operators and give them the opportunity to object to horizontal wells.

We think that the original requirement to submit an AFE and notify all the owners within the spacing unit and, in some cases, even the royalty owners was not necessarily appropriate. Most of that should be governed under a contractual arrangement. It should be able to be handled in that fashion. We think that the offset operator is the primary person that needs notification of a project.

There's also an item here on item G that I'm not real clear about and that is that, "In the event that there are any existing wells within the project area then the project well, if and when approved by the Division, shall constitute a special exception to the then existing well spacing pattern established by the Division for that pool."

I have a little bit of a problem with that statement, because I don't think that that's necessarily the case. In many cases you may find it's the first well drilled into a spacing unit, it may all be contained within the spacing unit itself. In fact, it may all be contained within the setbacks for a Blanco Mesaverde or some 40-acre oil pool. And in those cases it clearly wouldn't designate a -- or shouldn't be designated as a special exception. I guess I would view that as an inappropriate statement to have in our administrative approval rules.

And I would suggest that we delete item G as well.

And that concludes my comments.

CHAIRMAN LEMAY: Okay. Would you mind answering a question if one of the --

MR. HAWKINS: Sure.

CHAIRMAN LEMAY: -- Commissioners had one?

MR. HAWKINS: Sure.

CHAIRMAN LEMAY: Do you have any questions on --

COMMISSIONER CARLSON: Yeah.

CHAIRMAN LEMAY: -- what Amoco's stating?

COMMISSIONER CARLSON: Mr. Hawkins, it just occurred to me -- something you said about notification to royalty owners. As you know, I represent a royalty owner on this Commission.

What if a project area crosses a lease boundary? How are -- If the royalty owner is not notified, how is that production allocated between leases?

MR. HAWKINS: Most of the time -- and I might want to defer to a land negotiator on this, but I think most of the time the leases are joined either by force-pooling or by voluntary pooling into a spacing unit.

COMMISSIONER CARLSON: So it would be a communitized area before this would ever occur? I'm not --

MR. HAWKINS: That's correct, that would be my understanding, is that would be joined on an acreage basis, generally.

COMMISSIONER CARLSON: Generally. There wouldn't be any --

MR. HAWKINS: Well, I suppose you could pool -- you could voluntarily join it in some other fashion, but it's --

COMMISSIONER CARLSON: Yeah --

MR. HAWKINS: -- generally done on an acreage basis.

COMMISSIONER CARLSON: Sure. Okay, that's all I have.

CHAIRMAN LEMAY: Okay. Bill?

COMMISSIONER WEISS: Yeah. On allowables up in the northeast, I didn't quite follow you there. You say the --

MR. HAWKINS: Northwest.

COMMISSIONER WEISS: Northwest, right, I'm sorry.

The current practice is to -- It's based on the number of wells, not the number of proration units?

MR. HAWKINS: Well, for the most part in the Blanco-Mesaverde, the spacing units are 320 acres --

COMMISSIONER WEISS: Okay.

MR. HAWKINS: -- already.

COMMISSIONER WEISS: And you have one well, and the allowable is what?

MR. HAWKINS: It's based on that one well.

COMMISSIONER WEISS: Okay. Now, you get two wells. Then what happens?

MR. HAWKINS: And it's based on the two wells, one well in each --

COMMISSIONER WEISS: Is it twice the first?

MR. HAWKINS -- quarter section.

No, it's a combination of an acreage contribution and a deliverability contribution --

COMMISSIONER WEISS: Okay.

MR. HAWKINS: -- so it takes into account how well the wells produce.

COMMISSIONER WEISS: Yeah, okay. So then three wells again, the horizontal well producing --

MR. HAWKINS: Yeah.

COMMISSIONER WEISS: -- much more, it would --

MR. HAWKINS: And the way that that's been handled up there is that when you get the third well in, the allowable is based on only two of the deliverabilities.

In fact, that was one of the first cases that came up in the northwest, was, how do you handle the allowable?

And the decision out of the Commission was to take two of the wells, calculate the allowable for that spacing unit, and then allow the three wells to produce.

COMMISSIONER WEISS: And your suggestion is, use all three wells?

MR. HAWKINS: Just continue to produce all three wells, but limit the allowable to two -- to the deliverability from two of the wells.

COMMISSIONER WEISS: Okay, thank you.

MR. HAWKINS: I'm really not suggesting anything different than what's being done today, a continuation of that practice.

CHAIRMAN LEMAY: Just one comment, Mr. Hawkins.

How do you view this idea of taking the setback distance times two and drawing in those proration units into the allowable? Have you -- Do you have a comment on that one?

MR. HAWKINS: Well, I haven't really thought about that. It's the first time I saw it today.

I guess I can understand if you've got a horizontal lateral that comes right up next to the edge of a spacing unit and it's pretty clear that that other spacing unit is going to be drained, that maybe you had better include that into the allowable and into the project.

You certainly wouldn't want to exclude it and have them be not participating in the well and not, you know, sharing in the production.

So I think that's probably a reasonable way to handle it.

CHAIRMAN LEMAY: Anything else?

Thank you very much, appreciate that.

Mr. Kendrick, do you want to give us some comments here --

MR. KENDRICK: Yes.

CHAIRMAN LEMAY: -- the way Mobil feels about all this?

MR. KENDRICK: I have a letter to include in the record.

Mobil Exploration and Producing US, Inc., just has a couple of comments.

Basically, Mobil supports Meridian's approach. And as between Meridian and Marathon, I think -- believe simpler is better. So to the extent that Marathon is requiring less information to be put into an application, generally Mobil supports that, though I think I personally like the idea of categorizing the horizontal wells and defining them more precisely. That sounds like it's not too burdensome, and it produces some good information.

So that the other two specific points are that Mobil would like to make sure that injection wells are covered in the definition of directional-drilled wells.

I think that could be accomplished either by including the word "wellbore" in the definition of "directional drilled well", because "wellbore" includes the word "injection" in the definition. So in the definition of "directional drilled well", if we could say "directional drilled well" means a wellbore which is intentionally deviated, et cetera, and that would include the idea of injection well, as well as production well, or we could say means a production or injection well which is intentionally deviated.

Either way, Mobil would like to get across the concept clearly that an injection well is covered by this rule.

And the other point Mobil would like to advance is that a special test allowable be included in this rule.

I've had some experience with this where a special test allowable was granted for a three-month period. 200 percent of production -- 200 percent of the normal allowable was allowed for three months.

And here we're kind of stepping -- We're not addressing the more complicated issue that we've been discussing this morning about how you determine the allowable in an area where you have vertical and horizontal wells, but just for the purpose of gathering valuable data to allow the administrative approval of a special test allowable, and in this case that I cited in my letter, it was for 200 percent of the allowable for three months, with a make-up period of one year, at the end of the test period, starting at the end of the test period.

So this isn't a bonus allowable; it's something that would be made up, but just a way to, I guess, produce more, to acquire more information during a test period.

I think I heard Mr. Stogner say that he would recommend that this kind of special test allowable be approved administratively.

So really that's the -- that concludes my comments.

CHAIRMAN LEMAY: Bill?

COMMISSIONER WEISS: No, I don't have any questions.

CHAIRMAN LEMAY: Okay, I don't either then.

Thank you very much, appreciate it.

Larry Sanders, do you want to tell us what -- Are you representing Phillips or the Permian Basin Petroleum Association or both?

MR. SANDERS: I have two hats on today --

CHAIRMAN LEMAY: Okay.

MR. SANDERS: -- but I'm just going to wear one of them.

CHAIRMAN LEMAY: Okay.

MR. SANDERS: I'm going to appear as a representative for the Permian Basin Petroleum Association.

My name is Larry Sanders, and I'm currently employed by Phillips Petroleum Company as a regulation specialist. And as I said before, I'm here today representing the Permian Basin Petroleum Association.

I've just been recently appointed as Chairman of the PBPA Regulatory Affairs Committee, appointed by Executive Vice President Bob Kiker. The PBPA does thank the Commission for allowing us to present our comments and concerns.

Some clarification from our draft letter here. We have been working off of the draft that we received at the February hearing, so we're very pleased with the changes that have been made here by Meridian, Marathon and some of the other recommendations. So our comments are more directed at the previous draft that we did have.

Some of the things that we did concern was the vast amount of information that was being required for an administrative approval process. We felt like that administrative approval process should be simpler for both the industry and the Commission to process.

There's a lot of required data there that was basically the same information that was required for a hearing.

A cost reduction -- a large portion of the cost of coming to the hearing is preparing for the hearing, not necessarily coming to the hearing. We look at it as coming to the hearing is part of the benefit too, to get a trip to Santa Fe. I always enjoy those.

We commend the Commission for taking the initiative to allow this hearing, and we commend the people that started the process for an administrative approval process. We just felt like it was far too detailed for an administrative approval procedure.

Our subcommittee, in looking at this procedure felt like that we could get together, or a small working task force could get together and hash this thing out in a day to a good, workable draft that would be acceptable to both the industry and the Commission.

In looking at the changes that have been offered here today, we feel like it could probably be hashed out in a half a day, and we would like to support and provide our assistance in helping the OCD draft that.

I know that you all are time-constrained on a lot of these things. We have the ability and the time, and some people that could come in from various backgrounds, both engineering, geological and regulatory, that we could assist -- not necessarily having the PBPA do it, but ask one of the applicants themselves, maybe a five-, six-member task force could work this thing out very, very quickly, have someone from the OCD on there.

And I'll be more than happy to answer any questions.

CHAIRMAN LEMAY: Commissioner Carlson or Commissioner Weiss?

COMMISSIONER WEISS: I don't have any questions.

CHAIRMAN LEMAY: I've got one, Larry.

MR. SANDERS: Yes, sir.

CHAIRMAN LEMAY: I notice you did recommend a task force. We've talked about that.

MR. SANDERS: Yes, sir.

CHAIRMAN LEMAY: We're forming so many task forces, we felt this could be a slam-dunk or kind of a quick kill, so to speak.

But as an alternative to a task force, could you get together with your group and submit a draft, a draft order?

MR. SANDERS: I think we could, yes, sir.

CHAIRMAN LEMAY: I think that could be the same thing in essence --

MR. SANDERS: Yeah.

CHAIRMAN LEMAY: -- and then indicate on that draft order those parties that participated in it --

MR. SANDERS: Yes, sir.

CHAIRMAN LEMAY: -- because I think that's what I'd like to do, is ask those of you that haven't had input comment, to leave the record open to submit a draft order, and indicate on that draft order those companies that participated in the draft order, in support, which you're submitting to the Commission.

Because we're close -- I mean, I think us hearing here today are awfully close to coming up with an order. And rather than -- We've got these committees all over the place. Rather than --

MR. SANDERS: Well, again --

CHAIRMAN LEMAY: -- form another one, I'd rather try and do it --

MR. SANDERS: Yeah. Again, when you're talking about a work committee, you have something there to whittle out.

The testimony that's being provided here today, you can lay it out on the table, and that working task force can hash that out.

It's not like we're going to start on House Bill 65 where we start from a blank sheet of paper and there's going to be a lot of input and a lot of data that needs to be gathered.

I think we have the data, we have the expertise. And when I say now that this can be hashed out in a half a day by some of the participants here, to hand you a final working draft is what I was referring to.

CHAIRMAN LEMAY: The problem with that --

MR. SANDERS: Again, I --

CHAIRMAN LEMAY: -- we did this before, is, the draft order, then -- those that weren't included in the committee will say, I never had a chance to comment on the draft order.

MR. SANDERS: Yeah.

CHAIRMAN LEMAY: Why didn't it was sent -- Why wasn't that sent out --

MR. SANDERS: Yeah.

CHAIRMAN LEMAY: -- to everyone? Why wasn't testimony presented on the draft order for cross-examination?

I mean, that's the process, and --

MR. SANDERS: Yes, sir.

CHAIRMAN LEMAY: -- and what we've done is used committees in that light.

With this particular deal, we had a kind of a straw man out there that people take shots at, and then we're coming up, I think, as a Commission with a consensus.

And what can help in that, of course, is a draft order --

MR. SANDERS: Yes, sir.

CHAIRMAN LEMAY: -- by any committee that you can put together. And we'll certainly weigh that heavily.

MR. SANDERS: Okay, I'll go back to the PBPA and given them that information --

CHAIRMAN LEMAY: Okay, Bill, maybe you have a comment?

COMMISSIONER WEISS: I have a comment.

I wonder if a telephone wouldn't work here?

MR. SANDERS: It could do it, yes, sir. Conference calls are becoming the very thing. I know our company, our --

COMMISSIONER WEISS: And probably draft orders came in the same.

MR. SANDERS: Yes, sir.

FROM THE FLOOR: If they all came in the same, we wouldn't need the phone call.

CHAIRMAN LEMAY: We're not doing a political survey where we weigh how many of them come in.

MR. SANDERS: Yeah, I think there's just -- And like I say, in sitting back and listening to the testimony today, I agree with you that we are very, very close.

There's a couple items that hadn't been brought up that we will address as the PBPA, but we'll send those in to you, and the reasons behind those comments.

We feel like if there's going to be a lot of activities within the boundaries of the unit itself, the proration unit, the producing interval or something like that, a lot of our members aren't too concerned as far as notification to offsets.

It's when you get within the -- very near the lease lines, the exceptions to the rules are multiple allowables over what's assigned, that we're concerned with there, so -- the protection, so -- We heard comments both in favor of it against that.

But yes, sir, we'll be more than happy to --

CHAIRMAN LEMAY: Appreciate it.

MR. SANDERS: We're going to need a little time. We're small, and we're just forming. I don't know what kind of time limit you were concerned with.

CHAIRMAN LEMAY: Two weeks give you enough time?

MR. SANDERS: Three would be great.

CHAIRMAN LEMAY: I was going to say one.

MR. SANDERS: My company's going through reorganization too at the time so -- Yes, sir, we'll see what we can do for you.

CHAIRMAN LEMAY: Thank you very much.

Is there anyone else that's here, would like to -- Ruth?

MS. ANDREWS: I would like to submit the written comments of Arco and Texaco. Some of their concerns have been addressed.

CHAIRMAN LEMAY: Okay.

MS. ANDREWS: I would also like to make a suggestion that NMOGA would be happy to facilitate consensus of the people who have commented, and probably could do that within the week --

CHAIRMAN LEMAY: Well, thank you.

MS. ANDREWS: -- working with our Regulatory Practices Chairman, Tom Kellahin.

CHAIRMAN LEMAY: Wonderful. Can you wear two hats, Mr. Kellahin, one representing Meridian and the other criticizing --

MS. ANDREWS: I think we all are -- I think we're very close here today.

CHAIRMAN LEMAY: I think so.

Can I ask one quick one on this, Ruth?

MS. ANDREWS: Yes.

CHAIRMAN LEMAY: In summarizing this, is Arco saying simpler is better?

MS. ANDREWS: Yes --

CHAIRMAN LEMAY: I think so.

MS. ANDREWS: -- and I believe Texaco is saying the same.

CHAIRMAN LEMAY: And Texaco is saying the same.

MS. ANDREWS: They are both standing in support of the effort.

CHAIRMAN LEMAY: Okay. Is there anyone else that has some comments to make here?

Mr. Kellahin, could I just ask you, because we've all kind of taken pot shots at Meridian's Application, to give you the last shot at it and summarize and kind of express Meridian's feelings on this?

MR. KELLAHIN: Well, thank you, Mr. Chairman.

I think the process that we have engaged on has been successful. We've had a lot of prior response from a number of companies that we've not shared with you.

This is no longer a technical activity. We are ready to have you gentlemen make some decisions about giving us some directions so that we finish the clerical part of the presentation.

One issue remaining is what to do about definitions. You've heard that discussed, pro and con. You need to give us some guidance on what to do with definitions.

When you go to the components of the application itself the issue is, simpler is better, and you need to balance that with Mr. Carlson's concern about having adequate notice in the public-hearing process so that people can make informed decisions. Accordingly, we need your guidance on a couple of the items.

One of the items is the type log. It's number (5) on the checklist. We recommend to you that a type log with regards to the portion of the pool to be accessed be included in information. It's incredibly important for our geologist to know what their geologist thinks is the formation they're going to access. It's often in dispute.

It's important and easy to do, to tell us with a portion of the type log, where they're going to be. That is an area where you need to decide.

(6) is a written summary of stimulation programs, casing. We've -- Everybody's said, take that out. You can decide, but the consensus is take (6) out.

The consensus is, take number (7) out. It dealt with a written summary of abandonment procedures.

There is an issue about number (8). Amoco has suggested taking number (8) out, which was a disclosure by the applicant about what the proposed allowable for the project would be. I think that's useful information.

If I'm offset, I would like to know what the applicant proposes for an allowable. As you can see, if it's a Mobil application, Mobil is probably going to ask for some kind of special test production rate so they can do some science. I think I ought to know that.

Amoco has suggested take it out. We argued, leave it in. It's easy to say it's inherently part of the Application, you ought to tell us as an offset what you're asking for.

Number (9). Number (9) is an issue of policy you need to give us guidance on. Number (9) deals with the concept of explaining why you're doing the horizontal technology within a spacing unit that has an existing wellbore. It goes to a regulatory issue.

The regulatory issue is, vertical wells or horizontal wells have a certain spacing pattern to them. If that spacing pattern already has a vertical well, you're being asked as a regulator to make a decision on infill drilling. It constitutes a special exception. People ought to know, and you as regulators ought to know what the application is seeking for increased density.

You can decide how much he submits, I guess, and you could tone down the content, but there ought to be some disclosure of what he's trying to achieve with the horizontal well. If you disagree, then strike (9).

(10), I think everybody agrees that the cost of that project is a matter of the interest owners. You could probably delete (10). Everybody agrees to take (10) out.

(11) has an issue in it that you need to consider. The issue is, how much of a regulatory concern should you have for the interest owners and their correlative rights within the spacing unit? And there's a whole complex series of equities involved.

The Land Office has some. If they're contributing an acreage to a project area, they may want some notification, they may want consent, they may want to know what's happening.

You may decide it's not important, that you don't want to be involved internally to the spacing unit, but there are some incredible contractual and regulatory wars among interest owners in terms of how many of these horizontal wells are drilled in a current vertical project. If you choose not to have that as a matter of policy in this kind of case, you need to strike (11).

(12) deals with offset. Commissioner Carlson's point is well taken. There's a drafting error here, because it should be the obligation of the Applicant to tell that offset how many days he's got in which to file his objection, and we can take care of that issue.

The question about how to handle an allowable, you could take out the whole allowable concept, I guess, you could use something that we have suggested with Meridian, you can do whatever you want to do.

But I think we need some guidance on a minimum fallback default allowable. There ought to be some basic threshold allowable where if you file a plain-Jane application the whole world is going to know how to calculate that allowable.

And for example, if you decide to take every 40-acre tract in the spacing unit, and if it's Commissioner Weiss's 16 spacing units, that may give too big an allowable to be produced out of a single well. And if that's to happen, the offsets ought to at least be told, so that they can trigger a hearing and we'll go fight that issue.

Mr. Hawkins suggests on page 7 that you take G out. It's a policy decision for you. I, as a draftsman, put it in because I was thinking that these horizontal wells constitute special exceptions, because invariably they are project areas of multiple spacing units.

And inherently, by approving these, you are also approving a nonstandard proration unit, and almost always you're changing the density for the pool.

And I wanted it clear as a regulatory lawyer that once I got a horizontal approval administratively, that that gave me specific approval from the regulators to change the density in the pool, and I wouldn't have anybody complain.

Again, it's a policy decision, it's a drafting question. If you want it out, it's easy to take it out. I recommend you keep it in.

At this point, we would recommend, Mr. Chairman, gentlemen of the Commission, that with some guidance and direction from you, and with the opportunity for people to provide additional drafts or comments, if you desire, that you ought to delegate this to Mr. Stogner, who's had a wealth of experience. Many of the things we've drafted for you came out of hearings before him, and he is your best resource to give us clear guidance on how to complete the process.

Thank you.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin. And thanks to all of you.

We've tried something a little different here. We've taken an application, rather than create a committee, and put it out there, and we've had some modifications to that, and there will still be the opportunity to comment. We'll leave the record open for three weeks.

What I'd appreciate your doing in your comments, would be most helpful to us, is take one of the two draft orders that you've seen here today, either the Meridian order or the modified Marathon order, and mark it up as to your comments so that we don't have a lot of new things coming in that we have to deal with. To be honest with you, if there hadn't been comment on some new concept, there would be very little chance of it being incorporated into a draft order.

So to be helpful to us and to be constructive, we'd like to have the comments revolve around changing the two draft orders that you have out there and then submitting those to us with the people behind that draft submittal that would agree with it.

Permian Basin, of course, is one. If NMOGA wanted to do that, they could -- they've got, certainly, Texaco's comments in there and Arco's. So you know, with that, that may be enough.

But we shall leave the record open three weeks for additional comments, and at that time we'll take the case under advisement.

Again, thank you very much for your participation.

(Thereupon, these proceedings were concluded at 12:30 p.m.)

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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 Commission 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 May 10th, 1995.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998