NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date JANUARY 18, 1996 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
Mark McClelland	Conoco	Midland
W. Kellahin	Kellahin & Kellahin	Santa Fe
Jerry Hoover	Conoco	Midland
Pam Staley	Amoco	Denver
RANDALL CATE	ENRON O+G	MIDLAND
PATRICK TOWER	" "	" "
Tanya Trujillo	Campbell, Carr & Berge	S.F.
Frank Gray	Texaco E&P INC	Midland
James Bruce	Hinkle Law Firm	SF
SCOTT B. D[illegible]	ME[illegible] & NMOGA	FARMINGTON

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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:

HEARING CALLED BY THE OIL CONSERVATION DIVISION TO AMEND RULE 303.C OF ITS GENERAL RULES AND REGULATIONS PERTAINING TO DOWNHOLE COMMINGLING

CASE NO. 11,353

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

BEFORE: WILLIAM J. LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
JAMI BAILEY, COMMISSIONER

January 18th, 1996

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission on Thursday, January 18th, 1996, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

January 18th, 1996
Commission Hearing
CASE NO. 11,353

(Continued...)

I N D E X (Continued)

ENRON WITNESS:

* * *

E X H I B I T S

NMOGA-Conoco-Meridian-Amoco

	Identified	Admitted
Exhibit A	13	-

* * *

Meridian	Identified	Admitted
Exhibit 1	21	67

* * *

Amoco	Identified	Admitted
Exhibit	104	126

* * *

Conoco	Identified	Admitted
Exhibit	139	150

* * *

Enron	Identified	Admitted
Exhibit 1	164	192
Exhibit 2	170	192
Exhibit 3	172	192
Exhibit 4	175	192

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* * *

WHEREUPON, the following proceedings were had at 9:50 a.m.:

CHAIRMAN LEMAY: Okay, we shall resume.

One small bit of unfinished business here. Fellow Commissioners, you've read the minutes for December 14th and 15th, 1995. Do you have any corrections, or do you approve?

COMMISSIONER WEISS: I have none.

COMMISSIONER BAILEY: I move for approval.

CHAIRMAN LEMAY: Thank you. It's been moved. Do you second?

COMMISSIONER WEISS: Yes.

CHAIRMAN LEMAY: The approval of the minutes as presented, that's been moved and seconded and approved unanimously.

We shall now call Case Number 11,353, which is the matter called by the Oil Conservation Division to amend Rule 303.C of its General Rules and Regulations.

Appearances in Case 11,353?

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of the New Mexico Oil and Gas Association; Conoco, Inc.; Meridian Oil, Inc.; and Amoco Production Company.

MS. TRUJILLO: Mr. Chairman I am Tanya Trujillo from the Santa Fe law firm Campbell, Carr and Berge. I'm appearing today on behalf of Enron Oil and Gas Company.

We will have one witness today.

CHAIRMAN LEMAY: And how many witnesses, Mr. Kellahin?

MR. KELLAHIN: I have three witnesses, Mr. Chairman.

CHAIRMAN LEMAY: Okay.

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

CHAIRMAN LEMAY: How many witnesses, Mr. Carroll?

MR. CARROLL: No witnesses.

CHAIRMAN LEMAY: No witnesses.

MR. BRUCE: Mr. Examiner, Jim Bruce from the Hinkle law firm in Santa Fe, representing Pogo Producing Company and Santa Fe Energy Resources, Inc.

I do not have any witnesses.

CHAIRMAN LEMAY: Okay. Any other appearances in the case?

Those witnesses who will be giving testimony, would you please stand and raise your right hand?

(Thereupon, the witnesses were sworn.)

CHAIRMAN LEMAY: Mr. Kellahin, you may begin.

MR. KELLAHIN: Thank you, Mr. Chairman.

Mr. Chairman, this case was placed on the Commission's docket in August 3rd of 1995 for consideration of changes to what we know as Rule 303. It is the statewide downhole commingling rules.

As part of that hearing process, members of the industry gathered together, and certain of those industry members formed what I will call an industry committee. That industry committee presented to you some specific requests and then some general ideas for rule changes back then.

The initial specific request was to relax the administrative rules by which downhole commingling was processed so that in those spacing units where there was a difference of ownership you would not be compelled to take those to a hearing in the absence of objection.

In response to that request the Commission entered an interim order, which I have handed to you, in September of last year, which accomplished just that. The industry appreciates that. It was a meaningful, important change to us. It allowed us to avoid the expense and time of a hearing so that we could continue to process administratively those commingling cases that in fact had differences of ownership in the absence of objection.

In addition, it added formally into the rule notification to the State Land Office of commingling. That was a process that had been going on informally, but now it was attached in the rule.

As part of that preview back in August, then, we asked the Commission to give us an opportunity to examine and consider other rule changes. As part of that process, the industry committee has examined a number of major issues or items.

To help you understand our presentation today, I have organized a prehearing statement that has some length to it. The reason for the length is to give you a checklist of the issues, so that you understand what the industry's request was as to that issue.

In addition, as to each item, within the context of that item there's a header that refers to the Division. That is the Division's response to our committee's request for action on a rule change.

And so you have before you for policy decision and for deciding on changes for the rule what the industry has suggested, how the Division and the Division staff have responded, and then ultimately, then, you'll be able to decide how this rule is modified.

The composition of this technical group is:

Mr. Alan Alexander and Scott Daves of Meridian in Farmington. Mr. Daves is going to make the first presentation to you today, and he's going to be focusing on the San Juan Basin.

Jerry Hoover and Mark McClelland, with Conoco in Midland. Jerry helped us not only with the San Juan Basin issue, he and Mark have got a specific commingling example for you to see what happens in southeastern New Mexico as to the shallow oil pools.

Bill Hawkins and Pam Staley of Amoco in Denver have participated with us, and Ms. Staley has got a presentation with regards to the San Juan Basin.

Finally, in January, Randy Cate of Enron joined our technical group, and he's going to present through Ms. Trujillo his presentation with regards to certain additional pools in southeastern New Mexico, which will involve the Delaware, the Bone Springs and the Wolfcamp.

To give you a taste of how the committee has gone through the process, we have numbered each of the paragraphs in the prehearing statement, and the first major theme was that in addressing Rule 303 there is a unanimous consensus among the industry that Rule 303 may be broadened in terms of scope.

You may remember our earlier discussions that 303 was adopted originally by the Commission some almost 30 years ago to solve a very basic problem. That basic problem was that there were dually completed wells in southeastern New Mexico which had fallen off, they were getting to the point where they were having to be abandoned unless commingling was allowed, and they went through a special procedure to develop Rule 303, focused on that alone, as a salvage operation for dual wells that now were reaching the end of their productive life.

We have found within the last five or six years, particularly in the San Juan Basin, commingling in these older reservoirs becomes a very important decision-making basis for the industry, and we are about to see a great many of commingling applications, not only to replace a dual well, but in terms of an initially new drilled well, which would not be drilled in any other way but as a commingled well.

There will be evidence for you to consider that particularly in the San Juan Basin, the Pictured Cliffs, the Mesaverde and the Dakota are all marginal pools and that when you come to that point in the life of the reservoir, operators like Amoco, Meridian and Conoco and others are making choices about further development, based upon whether they can package multiple layers together in a single wellbore and drill it initially.

We've had the Division consider these on an areawide basis, and they have done and they have acted accordingly to approve those. We are asking for an administrative procedure within this rule to let the

Division, should they chose to do so, process those kinds of cases on an areawide basis. That would be very helpful to the industry.

In addition, we're going to hit a number of these numerical standards. One of the numerical standards in 303 has to do with a pressure differential. Mr. Daves is going to talk to you about what in his mind is the important regulatory trigger or flag to worry about when you deal with commingling two reservoirs, and he'll have some suggestions to you on that topic, and I would invite you to ask him questions with regards to crossflow, pressure differentials and that component of the rule. So the pressure differential numerical component is one we're asking you to examine.

Another part of 303 that has been an incredible impediment to development and to effective production of hydrocarbons is the oil allowable under 303.

If you'll look at the order that you issued, attached to the order is a copy of 303 the way it's currently modified, and it's a convenient Exhibit A to look at, it's the first page of Exhibit A.

When you look at the tabulation, you will find one of the serious problems the industry has with the rule, and that is, the combined total daily oil production from the commingled zones can't exceed a certain daily rate.

And if you'll look down between 6000 and 7000 feet you'll see it's 40 barrels a day.

We are consistently finding, and Mr. McClelland will testify, that that rule has been a serious problem for Conoco in certain of their operations. And in fact I think we universally find in the industry that this table is much too restrictive. We're going to ask you to modify this table. There's several choices on how to make that modification.

One suggestion will be from Mr. Cate, I believe, as well as others, is that it may be reasonable to substitute for this table a rule that allows the oil production to be equivalent to the depth bracket oil allowable for the shallowest pool being commingled, and that would put the commingled well, then, on a level playing field with single wells in that reservoir. That's one solution.

The Division staff has suggested to us, and we certainly endorse their solution, to increase this table. And if you choose to do so, the Division staff has recommended that the table at least be tripled. Tripling the table is substantial relief. That is a serious problem for us with this table, is, it's much too restrictive, it's causing operators to abandon or postpone doing this work because the table is too restrictive.

We're going to talk about the new drills. We're going to talk about the economic criteria. This is another policy issue for you in the rule. The rule as it currently exists is based upon this old example, where the Division was looking to allow commingling when there was one zone that was uneconomic.

We suggest to you that it is not necessary to have a commingling rule that has an economic criteria to it. If you examine the components of your jurisdiction, which are waste and correlative rights, if you are satisfied in commingling situations that cross-flowed production can be recovered and you can do so without damaging the reservoir and the fluids are compatible, then no waste occurs. If you can properly allocate so that all interest owners in each pool get their fair share of that recovery, then that's what you do to protect correlative rights.

There's nothing that we can find in examining this issue that causes us to believe that the regulators should have an economic standard in the rule. And so we ask you to examine that as a policy decision.

If you choose to keep it in the rule, we would recommend to you that you modify the language and give us the opportunity to at least demonstrate that only one zone is marginal, and we can discuss marginal versus uneconomic.

But we would like some flexibility in the rule so that an operator does not choose to avoid commingling because he sees an economic standard in here. We think there's a way for us to satisfy your concerns if economics is an issue and to substitute a different word. And we'll present solutions for you that Mr. Daves has done on a case-by-case basis before an examiner in the San Juan Basin. And it's nicely presented, and we'll show that to you soon.

The other thing that has arisen out of discussions with the Division is the concept of a reference case. And so when the witnesses talk about a reference case, I want to take a moment to explain to you what we are saying.

One choice for you is to create a commingling rule that is useful in the San Juan Basin, as well as a separate commingling rule for southeastern New Mexico.

You will find that there is a consistent consensus for the operators in the San Juan Basin that downhole commingling is timely at this point for them to continue their operations. You may find that there are selective reservoirs in southeastern New Mexico for which it's also suitable. But you also may find that there are newer pools down there for which you have some concern about letting them have a different set of numerical standards, for example.

The Division has suggested a solution which is different than having two sets of rules, which would be to address the commingling rules, such that they are modified on a statewide basis, but to adopt a process where the Division and/or an operator could ask for, in a particular reservoir, or an area, for a reference case, and they will come in like Mr. Daves is about to show you with a reference case. He's going to show you a reference case.

His reference case is going to be one where, if he's convincing, you can the delete the pressure-differential rule for the pools for which there's a reference case. His example he's going to show you is in the Pictured Cliff, the Dakota and the Mesaverde. He's going to ask you to have findings today that will qualify those three reservoirs in the San Juan Basin as a reference case by which the operator need no longer provide information on pressure differentials and crossflows.

All the applicant needs to do to commingle in the San Juan Basin will be to file the application and put the order number for the reference case as to that exception. He will continue to have to satisfy other criteria about the allocation, anything else that the reference case did not address. So that's what we're going to be talking about when you see a reference case, and Mr. Daves has got one for you.

The other thing that we have done, and particularly this group, is, they have visited with the Bureau of Land Management, they have gone to all the OCD District Offices, and they have a consensus among the BLM and the OCD people with regards to the adoption of a form. You do not yet have a standardized form for commingling.

Mr. Jerry Hoover with Conoco initiated with our input a form. We have a form for you to consider. The form is attached to the prehearing statement. In all instances, we still have to visit with the Land Office about any suggestions they have with regards to the form. But at this point everyone else, we believe, with the exception of the Land Office, has seen and has liked the form. It would standardize the process, it would minimize the paperwork, and everybody would see the form and begin to understand these all with a common vocabulary.

You'll have testimony from Mr. Daves about what he thinks are the important regulatory triggers. Fluid compatibility, in his opinion as reservoir engineer, is the key element that requires attention, and he will talk to you about what he means when he talks about fluid compatibilities and commingling examples.

I believe that summarizes, Mr. Chairman, what we propose to show you this morning.

If there are not questions for clarification, I'm prepared to call Mr. Daves, and we'll start looking at the San Juan Basin.

CHAIRMAN LEMAY: Okay, do either of my fellow Commissioners want to ask any question at this point?

Okay, well, let's start with the San Juan, Mr. Kellahin.

SCOTT B. DAVES,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Scott Daves. I'm a senior engineer with Meridian Oil in Farmington, New Mexico. I'm a 1987 graduate of Colorado School of Mines, and I've been employed with Meridian Oil since I graduated.

Q. Mr. Daves, on prior occasions have you qualified before the Division as an expert petroleum engineer?

A. Yes, I have.

Q. And on prior occasions have you repeatedly testified before the Division on downhole commingling cases in the San Juan Basin?

A. Yes, I have.

Q. And through your testimony we have developed, on a case-by-case basis, orders that have addressed the commingling of Fruitland Coal gas with Pictured Cliffs gas and other combinations of conventional gas, one with the other?

A. Yes, I have.

Q. As part of your involvement in this process, have you continued to work with these others in examining all the issues which I described to the Commission just moments ago?

A. Yes, I have.

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

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) Let me have you help us set the technical stage, Mr. Daves, with regards to the general issue of commingling and have you take a moment and describe for us what is the opportunity for commingling in the foreseeable future in the San Juan Basin.

If you choose to do so, I know you have an exhibit that illustrates that opportunity, and it's found in the summary section of your exhibit book?

A. That's correct.

Q. All right, let's start there, if you don't mind.

A. Sure.

Q. If you'll turn to the green book -- We've marked this for the record as Meridian Exhibit 1, and then we'll simply talk of it as Exhibit 1 and look at the various tab sections.

Two-thirds of the way back through the book is an orange tab that says "Summary". If you'll turn to this and describe for us what you have concluded to be the opportunity for commingling in the San Juan Basin.

A. Okay, I'll do that. First off, in terms of commingling in the San Juan Basin, the map across the room here shows the various types of commingles that have been approved and are currently in production within the San Juan Basin. There are well over 300 now in the San Juan Basin, so there are a fair amount of commingled completions already in the basin.

Q. That map is reproduced as the first map behind the "Introduction" tab, is it not?

A. Correct.

Q. All right.

A. Okay, what the numbers on this page represent -- I'll back up here.

The 319, "number of completions", what that is are single completions in the San Juan Basin from 1990 to 1995. While this number may not be exact, the magnitude of it is reflected there. There have been approximately 319 completions, single-well completions, in the San Juan Basin, in the Mesaverde, the Pictured Cliffs and the Dakota.

There are approximately 6200 undeveloped drill blocks in the San Juan Basin. The San Juan is fairly large in areal extent. There are 6200 undeveloped drill blocks within the San Juan Basin, in the Pictured Cliffs, the Mesaverde and the Dakota.

At current rates of development, industry is developing less than one percent per year. So in other words, it's going to take a considerable amount of time to develop the asset that is there, approximately 117 years.

Total capital required, I'm going to switch gears here slightly. If we were to be able to commingle these different horizons as we see fit and as the standards apply, it would cost approximately $1.75 billion in order to complete all of these wells.

The reserves developed are significant, almost 5 TCF.

The royalties at a 12.5 percent rate, that's over $1 billion in royalties that would be brought in by developing in a commingled nature these reservoirs.

The ad valorem and severance taxes, almost a billion dollars there at an 8-percent rate.

Operating expenses. And why I put operating expenses in here is, this is the money that would go back into the economy, to the people that operate the wells, people that service the wells, the people that supply parts and equipment to operate the wells.

And the income tax amount at a 38 percent is approximately $1.2 billion dollars in revenues.

So it is significant. There is a lot of resource left in the San Juan Basin. The big question is, how can we economically develop that resource and turn it into reserves?

Q. How do you foresee that the operators, including Meridian, will go after these additional reserves in the future?

A. In a commingled-type situation.

Q. Why is that becoming the operators' first choice for new drills?

A. Simply a matter of economics in that the various reservoirs themselves are not economic, and I think the numbers in terms of number of completions relative to the number of open drill blocks reflects that. It is not economic to go out and drill stand-alone wells in the San Juan Basin any longer, with few exceptions.

Q. Is that economic conclusion applicable to the Pictured Cliff, the Dakota and the Mesaverde?

A. Yes, it is.

Q. And is that true on a Basinwide area basis?

A. I think it is. There are -- There will be rare exceptions. The Mesaverde is -- And the data in that will reflect that, in that section.

The Mesaverde is the one formation that probably is economic at this point in time, and I think the activity level within the Mesaverde reflects that economic status.

Q. As to the other two reservoirs, though, there is simply no doubt among all of you that those are now marginal reservoirs?

A. That's correct.

Q. In what particular way is the current Rule 303 a restriction or an unnecessary limitation with regards to encouraging this commingling activity?

A. In what ways -- Can you --

Q. Yes, sir. In what way does the current Rule 303, in your opinion, need to be modified in order to encourage or provide an incentive by which operators such as Meridian will go forward with these commingling wells?

A. Probably the single most important thing is a standard way to go about how we apply for commingles. Typically, in order for a company to drill a well, there's a set of procedures very clearly defined. You fill out a form, you go through that process. What we're asking --

and we will present a form that will basically allow us to do that on a one-form basis. That's the first part.

The second part is, we have an economic standard out there. Basically a lot of these reservoirs could go past that standard, but there are those exceptions to where you may be pleasantly surprised and find that a zone you thought would be uneconomic is not quite uneconomic. It's still going to be at a marginal level, but it would be economic in and of itself. And that's a rare occasion, but it can happen.

A third thing, and probably the most important part, is the pressure standard. The pressure standard -- The various reservoirs have differences in pressures that right now with this 50-percent rule, the way that it's stated, you couldn't commingle these wells for a certain period of time. So in other words, you would be delaying a process that probably could go on from the beginning, from this point on.

Q. There are two ways to approach the pressure differential, that numerical standard?

A. Uh-huh.

Q. One is to, in Rule 303, either modify or eliminate it, or otherwise change it?

A. Right.

Q. Or -- and/or, in a reference case for the San

Juan Basin, determine that it's not necessary and can be deleted as to those reservoirs in that area.

A. Correct.

Q. All right. Describe for us, for the San Juan Basin, why you think the current 50-percent differential is not an appropriate regulatory control to reach any conservation objective?

A. Okay, the several pieces that I have that can do that -- the pressure crossflow section in here, in this map, will help me considerably, and these maps over here.

Q. Let's talk about the concept. what should we, if we're developing regulatory rules, be worried about in a reservoir with regards to crossflow?

A. There's several pieces to that.

One is the ability of the gas to flow in and out of the reservoir. That's a key piece to it, and I'll talk about the mathematics here shortly.

And also the reservoir also itself, maintaining the integrity of the reservoir. In other words, not creating an unnatural situation in which you allow gas to escape out of the reservoir, either originally or through a crossflow process. In other words, putting more gas into the tank than the tank could possibly hold. It's a simple analogy that would hold in this case.

Q. Am I hearing you correctly that if you were the regulator, the issue of crossflow is not the issue for you, is it?

A. No.

Q. The issue for you is, will the commingling result in formation or reservoir damage?

A. Correct.

Q. Will the crossflow production ultimately be produced?

A. Yes.

Q. Without waste?

A. Yes.

Q. Will you be able to account to the interest owners for their share of that production, even if it's crossflowed?

A. Yes.

Q. And are the fluids compatible?

A. That's the key question in terms of, in the San Juan Basin there are likely exceptions where that is not -- where the fluids are not compatible. That needs to be studied on an areawide basis.

That is an issue that is probably the single most important issue within crossflow and commingling.

Q. All right. Let's set aside the fluid compatibility issue, then, and have you address for us as a reservoir engineer how we satisfy the other concerns with regards to the avoidance of formation damage or the loss of recoverable reserves.

A. Okay.

Q. How do we do that?

A. Essentially -- Can I walk through this exhibit --

Q. Well, give me the concept first.

A. Okay. Essentially, there are two aspects that define gas flow. One is the resistance of flow through the reservoir and the reservoir parameters, and also the differential of pressure that will go across that resistance. Okay.

In other words, you have a tank where the gas is stored and a valve and a choke system which the gas will go across. The ability for that gas to flow is a function of the pressure differential from the tank to the valve, and through the valve, and also the mechanical ability of the valve to allow gas to flow through.

And the things you worry about are damaging the valve or damaging the tank, in this case a reservoir and the sand face.

Q. Does this 50-percent-pressure-differential rule do anything to address those concerns?

A. No, no. It really and truly -- It's too vague a standard, that it doesn't address that. And I can walk through the mathematics and show why that's true.

Q. Let's do that.

A. Okay.

Q. It's under the tab, the blue tab, that says "Pressure/Crossflow"?

A. Yes.

Q. Is that where you are?

A. Right.

Q. And you want us to look at the first display behind that tab?

A. Right.

Q. All right, please continue.

A. What we have here is a derivation of Darcy's law that reflects gas flow from a natural gas reservoir. And what it is, is the deliverability equation. And there are numerous variations of this, but this is probably the most applicable for San Juan Basin applications.

And what I have done is, I have broken into colors. The orange color is the part of this that -- I'm going to define that term as the constant C. It's exactly the way it's described in that "Slip" Slider reference that I have. But what the orange terms are, that is in a sense the choke mechanism or the valve mechanism that controls flow out of the gas reservoir. Okay, this is the piece -- and I'll talk about it and how the rules affect that part.

Also, the P_r raised to the 2 minus the P_{wf} raised to the 2, raised to the n power, what that is, is that is the mathematical derivation of how gas flows in a reservoir into a wellbore. Okay, it's a standard equation. There are some variations to it, but this is primarily the one that we use to calculate deliverability and estimate production out of a gas reservoir.

So talking about the first term, C, what these terms are, the first part, the 0.703, that's just a constant to convert all these units into a term, MCF per day.

The h, that's the reservoir thickness. For example, in this case here, the Pictured Cliffs, that h may be 30 feet. Okay. For the Mesaverde, there are several pieces to that reservoir, but it would be the combined thickness of the sands that are flowing gas out of the reservoir and for the Dakota, so this applies to each of those.

The k here is the key piece. It's the permeability of -- the average permeability of each of the various reservoirs. Its units are typically in millidarcies in the San Juan Basin.

The u on the bottom part here, that's just gas viscosity. The gases within the San Juan Basin are all fairly close, so that u would be basically the same for each of them.

The reservoir temperatures are a function of depth, they're not -- they're fairly close.

The z, all that is -- These are non-ideal gases, so this adjusts for that fact.

And then the natural log times 0.606 re, all that is is the drainage radius of the reservoir, divided by the wellbore radius. It's a simple mathematic term. What that is, that is in a sense mathematically describing the choke function of a reservoir, or the resistance of the reservoir to flow gas, or the ability of a reservoir to flow gas.

What I've termed here in green the dP squared, this is the pressure drop through the reservoir to the wellbore, and the way that it's mathematically defined in terms of P_r is the reservoir pressure, and P_{wf} is the wellbore flowing pressure.

The n constant, that's the slope of the deliverability curve. It's also typically referred to as a turbulence constant. In the San Juan Basin that number runs anywhere from about .5 to 1.25. For mathematical ease here, we can say that it's one, and that piece will go away.

So what you have here, the ability of gas to flow out of the reservoir is equal to the C term, in other words, the resistance of the gas or the ability of the gas to flow out of the reservoir, times the pressure differential within the reservoir to the wellbore.

So if you were to put that in terms of a tank of gas --

Q. You're ready to turn to the next page?

A. Right.

Q. All right.

A. Turn to the next page. In other words, if you have a tank of gas -- it could be oxygen, it could be natural gas. The tank of gas and the pressure within the tank is the pressure term.

And then the C_{PC} here, that is the resistance of flow. You can -- Again, you can analogize to a valve choke mechanism to allow the gas to flow out of the reservoir.

So for the San Juan Basin case what I've said is, there's a C_{PC}, a C_{MV} and a C_{DK}. What those are is, that's that term for each of these various reservoirs. In other words, that's the resistance to flow through the various reservoirs.

What I have here, a P_{irPC}, that is the original reservoir pressure of the Pictured Cliffs in average. The P_{irMV}, that is the original reservoir pressure of the Mesaverde. The P_{irDK} is the original reservoir pressure of the Dakota. That's the three formations that we show here.

Okay, what I have here, the P_{rPC} is equal to 297 p.s.i. That's the current average reservoir pressure of the Pictured Cliffs. Same thing for the Mesaverde, the P_{rMV}, that current reservoir pressure is 536 p.s.i. And the P_{rDK}, that is the current reservoir pressure of the Dakota.

You can look through here and see that we have drained a considerable amount of gas out of these reservoirs. In other words, we're down to the last part of what's left within these reservoirs in terms of the magnitude of how much gas was there to begin with.

Why these original reservoir pressures are important is, that is the ability of that reservoir to store gas that Mother Nature gave it. In other words, that's the standard rating of that tank that Mother Nature allowed it to have. In other words, if it would have been able to hold more gas than that, it would have leaked off. In other words, that's why it got to where it is -- or was, I would say.

The reason it is where it is now is because we have been able to flow gas constantly across that choking mechanism so that we've been able to deplete that reservoir and capture those reserves in each of the cases.

So in other words, what I'm trying to say here is that Mother Nature has provided us with these standards, we have measured these standards for a considerable period of time, well over 40 years. We know what these numbers are in any -- Can you turn that map over, and we'll look at an example of that?

Q. Is this next display, Mr. Daves, also in the exhibit book?

A. Yes, it is. It's under the Pictured Cliffs section. It's very -- fairly difficult to really see any detail, but the coloring I'm going to talk about -- and you'll see that in one case -- In this case here, what this is, what this map depicts is, in aggregate, we pulled all the data that we could find within the San Juan Basin to find the boundaries and then evaluated what the reservoir pressures were initially in the San Juan Basin for the reservoir or the tank, the Pictured Cliffs, and that is the tank that we're looking at there.

The average reservoir pressure of that was 900 p.s.i. As you can see, the blue shading shows a lower pressure, and then the brighter the red or pink, the higher the pressure. So with depth that pressure has increased or was -- you know, proportionally it is higher with depth.

But what's important to note here is that we do have a database that's significant enough that we can go into almost any place within the San Juan Basin where productive Pictured Cliff gas is, and we know that what that original reservoir pressure is. We know what Mother Nature provided as a standard for us. It's there, it's mappable and it's observable. You can pick any location within that and go in there and see what that standard is for that reservoir.

We also -- if you want to turn the page, Alan -- we know what the current status of that tank is now, and you can see that we have a fairly good feel for what the reservoir pressure is for it now.

And one of the beautiful mechanisms that over the years that we've developed to track these pressures is our deliverability process, our proration process. We force ourselves to do this. In Colorado they never force themselves to do that, so they never have done it, so it's a guess when you cross the state line. But this state has been wise enough to know how to manage a gas reservoir and we've done that. So now we have the standards as to what it was and now what it is.

Okay, we have the same types of maps for both the Mesaverde and the Dakota, so now we have a good feel for what those measurable standards are in terms of what the reservoirs are capable of.

Q. Let's take a quick look at the other maps, then. What's the next one you have there, Alan? Is it the Mesaverde?

A. Mesaverde.

Q. All of these are in the book, they're a little

hard to see because the scale is so small. If you'll turn
to the Mesaverde, you're going to look at the original reservoir pressures --
A. Uh-huh.
Q. -- followed by a map that shows current reservoir pressures?
A. Current reservoir pressures, right.
And the way that you deplete gas out of a gas reservoir is to deplete the pressure. So we have done a fairly reasonable job of depleting these reservoirs, because the Mesaverde is approximately 40 percent of what it was originally. The Pictured Cliffs is approximately 30 percent of what it was originally.
So in other words, we've pulled these tanks down through a process such that we're in the very tail end of the life of all of these reservoirs.
And then -- Go ahead and move on through the Dakota. So now we have a feel for standards with which these tanks should be measured.
Okay, and this is the Dakota. In other words, we have a good feel for what the Dakota is and was, and then that's the final -- and what all the dots represent are where there have been commingles. So we have a -- you know, throughout these reservoirs we have indeed commingled them where appropriate.

So in other words, now we have some standards and some data that we've defined that define what those maximum parameters probably should be. And in my opinion that is a good minimum standard, and I'll talk about that and give you an example here, refer back to this cartoon.

Q. All right, we're going to go back to the blue tab that says "Pressure/Crossflow". We're going to look at the next display.

Let me ask you a question here. When we made this presentation to the Division staff in October --

A. Uh-huh.

Q. -- did you have the conclusion you're now presenting to the Commission available for Division staff --

A. No.

Q. -- with regards to a solution?

A. Not as developed, as I've worked. I've had several more months to work on it.

Q. All right. So what we're presenting now is not something the Division saw back in October?

A. We presented the maps and the first part of the data within this book, but not this part here.

Q. All right.

A. Okay.

Q. Have you determined whether or not there is any scientific basis for the 50-percent pressure differential rule in the existing 303 rule?

A. No, we couldn't find any technical merit for that basis.

Q. Let's go to the tanks now.

A. Okay.

Q. Show us what happens under the current 50-percent rule if you decided hypothetically that you wanted to commingle, let's say, the Dakota with the PC.

A. Okay. Under current standards -- You'll notice that the Dakota pressure is 746 and the pressure for the Pictured Cliffs is 290 p.s.i. Under current standards this would not be allowed, you could not commingle these two reservoirs.

But now if you look at what the original reservoir pressure of the Pictured Cliffs was, say 900 p.s.i., the 746 p.s.i. that the Dakota pressure has -- and understand, these are tight reservoirs -- even if you allowed over a fairly large period of time gas to flow from the Dakota to the Pictured Cliffs, the Pictured Cliffs reservoir itself, or tank in this case, is never going to see that 900 p.s.i.

In other words, you would have to fill that tank for a considerable amount of time. Understand, it took almost 50 years to take it from 900 p.s.i. to 297 p.s.i., and a significant amount of gas was taken out of that reservoir. You would have to allow crossflow to go on for a long period of time before you would ever exceed that 900-p.s.i. cap. In other words, you could fill that tank for a long period of time and never break the caprock or break the bottom rock that is associated with these reservoirs.

Also what is important is, the 746-p.s.i.-minus-297-p.s.i. pressure drop that you would see across your sand face choke system is not as great as the original 900 p.s.i. flowing into the P_{wf}.

In other words, when we first started draining this reservoir, the pressure drop across that choke system was never as high -- or was higher than it will ever see again through commingling these reservoirs.

Is that clear? Am I making that point where I'm not losing anybody?

Q. Let me ask you an example. If the regulatory trigger --

A. Uh-huh.

Q. -- is that commingling cannot result in a pressure that would exceed the original reservoir pressure in the lowest-pressured reservoir --

A. Right.

Q. -- that's the way to construct the rule, is it not?

A. Right, we have the data, we have the standards that would allow us to do that.

Q. The concern, is if you break the lowest-pressure container, then you're going to cause gas to go somewhere else, you might not get it back and you might damage the reservoir?

A. Correct.

Q. Doing the 50-percent limit accomplishes nothing?

A. Right, right, correct.

Q. And if it's there to control crossflow, that's not precluding crossflow?

A. Right, you could and you would -- If, say, the Pictured Cliffs was within the standards, and you were flowing gas and you shut the well, crossflow would still occur, and it would still be recovered. But you still have a much more efficient standard out there that you could use that is less arbitrary. We know what Mother Nature has provided us.

Q. Is this analysis applicable not only to the San Juan Basin but to other reservoirs in the state?

A. It would be applicable to typically any two gas reservoirs.

Q. So you don't see anything unique about the San Juan Basin that would require this rule to be limited only to the San Juan Basin?

A. No, I do not.

Q. Okay. Let's skip to another topic now. If the Division deletes the 50-percent differential and uses this original reservoir-pressure limit --

A. Right.

Q. -- as the control, there will be gas reservoirs with crossflow.

Give us an example of how you correctly allocate for that so that all interest owners get their share from the proper reservoir.

A. Okay, a good example of how we have approached this in the past is with the Pictured Cliffs-Fruitland Coal commingles. What we've done with those is, we've gone back to the technical standards of the Pictured Cliffs reservoir.

In the case of a new drill what we're able to do is drill the well, log the sand, figure out what the porosity parameters are, what the thickness porosity parameters are, what the water-saturation porosity parameters are, measure the reservoir pressure, calculate out a volumetric reserve base, look at offset data, confirm that volumetric data with material balance data.

We've been able to get these two numbers to converge to within ten percent to five percent. I mean, the data is fairly accurate and able to calculate out that Pictured Cliff production.

What we've been able to do at that point in time is test the Pictured Cliffs in terms of its producibility and also test the Fruitland Coal in terms of its producibility and ratio so that we have a starting point, an initial production rate, calculate the reserves, and then back-calculate a decline. We've done this several different times for the Pictured Cliffs. In fact, Meridian has pretty much used that as its -- where we can, used that as our standard. It's fairly accurate, and I have an example of one of those in the book, the Huerfano 549.

Q. We've done this repeatedly --

A. Yes.

Q. -- before the Division --

A. Right.

Q. -- and obtained through the hearing process --

A. Right.

Q. -- approval to do commingling using that allocation system?

A. Correct.

Q. And it's used by other operators?

A. Right, right.

And -- You know, and another way to calculate that is, in the case of a Mesaverde-Dakota dual, that you would want to convert to a Mesaverde-Dakota commingle. You've flowed both reservoirs, you have gathered both initial pressure data and deliverability, second-, third-, fourth-, fifth-point data, so now you have a material balance relationship and you have a production relationship, so you can allocate those reserves either based off production ratios or more rigorous material balance method.

So we have the methodologies out there at our disposal now and the data to do that.

Q. Let's complete the crossflow issue by going to the next display behind --

A. Okay.

Q. -- the blue tab, and let's talk about your proposed rule change that would give us a numerical standard that's got this scientific basis to it where you're tagging it to the lowest original reservoir pressure.

A. Right.

Q. Describe for us what you're doing.

A. What I have here is, what I'm saying is, the pressure drop through the reservoir is a function of the reservoir pressure, the flowing well pressure, and initially it was a function of the initial reservoir pressure.

So when you look at the bottomhole pressure -- The way the rule is stated now, the bottomhole pressure of the lower zone is not less than 50 percent of the bottomhole pressure of the higher-pressure zone, adjusted to a common datum.

That's -- I mean, there's no technical standard. I understand where the idea of the rule came from, but what I'm proposing here is what a more rigorous approach should be with some standards there to form our basis for this technical recommendation.

And what I've put in here in quotes, "The pressure of the **HIGHER** pressure zone **DOES NOT EXCEED** the **ORIGINAL PRESSURE** of the **LOWER** pressure zone adjusted to a common datum."

So it's just a change of wording, but it's a more rigorous application of the standards as we would need them.

Q. Let's see how this fits with the other controls within the numerical standards. If you'll start at the top of the page --

A. Okay.

Q. -- there's an existing 303 C b (iii).

A. Right, and --

Q. You're not going to change that one, right?

A. No, the first two rules here, the 303 C b (iii) and (iv), these are wonderful rules. I mean, these are the two rules that probably govern this most, and what I have said is that the ability for gas to flow out of a reservoir, or in and out of a reservoir in the case of a commingle and some crossflow, is a function of these two rules.

In other words, these are the rules that really need to be rigorously adhered to through the process of commingling, and they are protecting the reservoir and the ability of the reservoir to move gas in and out of them.

Q. When you go down to existing (vi), which is repeated as the third --

A. Uh-huh.

Q. -- text on this page, that adds nothing to the regulatory control over this issue?

A. Right, right.

Q. And you would suggest, then, the last setup here where it says "**REVISED**" --

A. Uh-huh.

Q. -- that's the last text, and you would suggest that as a substitute for the 50-percent differential rule?

A. Right, right, correct. In full gas reservoirs only.

Q. All right. Does that complete your discussion on that topic?

A. Yes, it does.
Q. Let's turn to the economic --
A. Okay.
Q. -- issue so the Commission can understand the kind of presentation that you have made before the Division within the context of a hearing --
A. Right.
Q. -- to see how we're addressing decisions with regards to whether a well is marginal or economic with regards to commingling.
A. Okay.
Q. Where do we look in the book to find that?
A. We can start with the Pictured Cliffs tab. Here again, I'm going to walk through a method of determining on a drillblock basis how much gas we can expect in that drill block, in that reservoir, in that tank, and why -- why the process -- and as I go through this, it should become clear why this process of commingling is becoming more and more important to prolong the economic lives and continue economic development of these resources.

In the Pictured Cliffs, original shut-in bottomhole pressures, the average pressure was 914 p.s.i., and through a -- as a function of the gas itself, the Z_i was 0.878. So you get a P/Z relationship of 1041. And I'll walk through what that means here in just a minute.

The shut-in bottomhole pressure currently is 285 p.s.i., and the P/Z for that is 297 p.s.i. In other words, we only have approximately 31 percent of the original reservoir pressure left in these reservoirs. In other words, we're down to the very end of it.

We have cum'd through this process of pulling down to this point approximately 947 million cubic feet per drill block. Okay, you can use -- It's a fairly straightforward approach. Plot the cumulative production of the reservoir versus -- and you would plot cumulative production on the X axis and the pressure drop over time, or actually the reservoir pressure over time, on the Y axis, to create a curve.

And I do have an example of one of these I'll refer you to in the "Examples" section. It's the very first color curve. So you see a visual plot of that process and how a reservoir engineer would calculate reserves.

Q. All right, let's make sure we're with you. You went to the tail end of the book, you've got the "Examples" tab --

A. Right.

Q. -- and where --

A. It's the "Example" tab, it's the first colored curve in -- That one right there.

Q. All right.

A. Does everybody see that? Okay.

So what you would be doing is plotting your cumulative production on the X axis and the pressure over time on the Y axis, so you can forecast out what the final pressure would be -- or actually what the cumulative production would be at the final abandonment pressure. In other words, the pressure with which you could economically no longer get gas out of the ground. Okay, so that's the methodology here.

So what we have determined is that the average Pictured Cliff wellbore or drill block has approximately 314 million cubic feet left. So if you were to go out to any drill block within the area, that's approximately what you should be able to expect, is that amount of gas.

Current average production out of the Pictured Cliff reservoir is approximately 45 MCF a day.

So now we have a reserve number and we also have a rate number. So we can guess -- We know approximately what we would return our -- as a return on investment, if we were to decide to go out and drill one of these drill blocks.

And what the next two maps show is the same maps that we showed up here, an initial and now a current reservoir pressure.

And the next page shows some numbers here that would describe drilling costs. And while there's a lot of numbers here with some fairly reasonable detail, there's only three numbers here that we really need to think about at this point in time. And the first one of those is, for a single completion, the total cost to drill one of these types wells, approximately $298,000 to drill a stand-alone Pictured Cliff drill block and develop that drill block as a stand-alone project.

As a dual completion would cost us approximately $250,000, so as a dual it is obviously a little bit cheaper to do that.

And as a commingle, the last -- very bottom number on the bottom right-hand corner, approximately $200,000 to drill a commingle well. In other words, to drill a well through to some point and commingle two of the horizons that we would be looking at. In other words, we could do the Pictured Cliffs and the Mesaverde, we could do the Pictured Cliffs and the Fruitland Coal.

Q. How has this issue been presented to the Hearing Examiners for a decision when the current rule has this requirement in it that at least one zone must be uneconomic?

A. In this manner right here, this is exactly how we have presented it.

Q. All right. When you have the cost components, how do you plot that against rate and EUR?

A. Rate and reserves, right.

So what we have here on the X axis, we have an initial rate.

On the Y axis we have the EUR. In other words, the amount of gas we can expect out -- In the case of the Pictured Cliffs, we could go in and say that our reserve number would be 314 million cubic feet and our initial production would be 45 MCF a day.

Well, you can see here in terms of an economic standard -- And what these three colored curves represent, for the blue curve what that is, is the threshold level that this project would be funded, for example, it's a 15-percent AFIT rate of return for a single completion.

We also have an orange curve here for a dual completion. We also have a green curve here for a commingled completion.

So in other words, the way to look at this would be -- and you can see the scale kind of depicts that you're going to need approximately, for a commingled well, for that reserve number of 314 million cubic feet, you're going to need an initial rate of 200 MCF a day for this well to be classified as economic, even as a commingle. Okay?

So in other words, the parameters that any of my industry counterparts would be looking at -- We have Pictured Cliffs drill blocks. We could use this curve and say basically, certainly I couldn't go drill a new well. Really, economically speaking, I couldn't go commingle a new well or dual a new well. In other words, the reserves that are left in the Pictured Cliffs are so small and the rates are so small we really can't do a whole lot with that asset as it is right now.

And the next curve here kind of bears out that statistic and that assumption and conclusion. What we have here, the blue curve or the blue bars represent how many wells that were singly drilled and completed in the Pictured Cliffs in 1990 through 1995. That's the blue bars.

In other words, in one year, the first year in 1990, we drilled less than ten. Now, understand there's several thousand drill blocks out there that we could go develop.

We attempted a few drill wells where we dualed. In 1991 you'll see the big spike there. That was the tail end of the Fruitland Coal drilling programs.

So the next obvious choice was to look at the Pictured Cliffs again. Well, you can see that people did and they discovered it really wasn't paying out the way they wanted, so the activity level has continued to drop off over time.

But you also notice that commingles since 1992 are beginning to come on. In other words, we're seeing an economic way to go at these resources and turn them into reserves.

What I have on the last slide for this section, in the last six years, approximately 81 stand-alone Pictured Cliff drill wells have been drilled.

Now, if you look at the number of undeveloped drill blocks, there's a huge amount of undeveloped drill blocks, almost 2400 drill blocks. In other words, we're developing approximately .6 percent of those drill blocks per year, and it's going to take us, in order to develop that entire resource, 175 years with the current standards as they are right now.

What that means -- And to turn that around, if we were to be able to commingle these -- We know we can't drill them, they're obviously not economic, so we're looking for another way to attack this. It would cost approximately $200,000 per drill block to develop. It would take approximately half a billion dollars to develop all of these drill blocks. We have approximately 314 million cubic feet per drill block to be developed, or 742 BCF of resource there that's currently uneconomic to develop.

In terms of what the State would get out of it and the federal government in royalties, approximately $170 million worth of revenues. At the rate that we're going now, that will never be realized.

In terms of ad valorem and severance taxes, approximately $90 million worth of revenues will never come into -- or will never be paid, because these projects will never be done.

Now, in terms of operating expenses, why I put this in here, this is what feeds the local economies of the San Juan Basin and the southeast part of the state.

And in terms of income taxes, approximately $133 million of revenues will never be paid because these will not be developed economically.

Q. Mr. Daves, do you believe the Commission could adopt as a policy decision the conclusion that the Pictured Cliff is a marginal reservoir and can be commingled at this point --

A. Yes.

Q. -- without regards to further approval?

A. Right.

Q. All right. Let's go through the Mesaverde, then, and show the similar analysis, show us where the numbers change and what is your ultimate conclusion, then, with regards to commingling concerning the Mesaverde.

A. Okay. Essentially the Mesaverde is the one bright spot in the San Juan Basin. Activity levels reflect that. There are enough reserves and there is enough initial production that we can get out of these reservoirs so that we can go and pursue these, and I think the activity levels reflect that. If you look at -- I have the same analogy all the way through, but what I would like to direct your attention to is the economic curves that are here, the same three curves I showed before.

With the current reserve rate of 1.4 BCF, obviously you can go out and do a fair amount of work -- on the X axis, if you find the 1.4 BCF level. If you get anything above that average rate -- In other words, if you had a well that was 300 MCF a day, initial rate, and that 1.4 BCF, you can afford to go and drill that well. This is the one case where you can. Out of all three of these horizons, it's the one zone that you could go do this with.

And turn to the next page, at the tail end of the Fruitland Coal drilling program, you see activity levels in the Mesaverde -- Let's see, you're -- you need to -- It's the next section in the Mesaverde, the very last several pages. You see that the activity level reflects those economics. In other words, the model is reflected in the statistics of what is going on within the San Juan Basin.

So this is the one zone that is the bright spot in the San Juan Basin.

But it's interesting to note here in the Mesaverde that in a sense it is already a commingled reservoir. You have -- Up on the upper part here, you have the Cliff House zone, which is a fairly thick mass of sandstone, you have a Menefee zone that has numerous smaller sands, coals, et cetera, and you have the Point Lookout, which is the bottom part. So in other words, there's three reservoirs that are commingled, and it is fairly economic. They're all similar reservoirs, and over time we have defined them as a reservoir.

Q. Well, what are the operators doing, then? If they still have a Mesaverde opportunity as a single completion, what do they do about any Dakota opportunity at that drill block?

A. Ignore it.

Q. What's a better way to go about doing that?

A. Drilling through to the Dakota and tapping both resources.

Q. On a commingle basis?

A. On a commingle basis.

Q. Okay.

A. And I would suggest that that's probably going to be a common agenda item on dockets in the future.

Q. Okay.

A. And in terms of the Mesaverde, the number of single well completions in the last six years, 175. However, if you look, there's still almost 1600 undeveloped drill blocks within the Mesaverde on the 320-acre spacing unit with the allowable of one infill in that. So there's a fair amount of drill blocks left to develop.

However, in terms of our development rate and in terms of the amount of opportunities that are out there, we're still doing less than two percent per year, on average, and it's going to take another 55 years to develop all of these drill blocks.

If we could commingle these reservoirs and commingle these with another one, the capital required to do that would be approximately $270,000 per well. The total capital required over time to develop all of these in this manner would be approximately $436 million. We would develop approximately 1.45 BCF per drill block or, in aggregate, 2.3 TCF of gas reserves. There's a fair amount of gas within this zone here.

If you look at the royalties that would be associated with this development, approximately almost a half a billion -- over a half a billion dollars' worth of royalties, $300,000 worth of ad valorem and severance tax revenues, operating expenses of almost a million [*sic*] dollars. So in other words, there's a billion dollars worth of operating expenses that would go back into the local economies. And in terms of income taxes, approximately $800 million worth of income tax would be generated from these projects.

And again, I have a similar analogy for the Dakota, same process of determining the reserves. The numbers that are important to note here are approximately 729 million cubic feet per drill block and approximately 85 MCF a day per well.

I have a pressure map for the Dakota showing original reservoir pressures. I also have a current reservoir pressure map for the Dakota, and here again I show the total cost to go and drill a stand-alone Dakota drill well right now is approximately $542,000, to dually complete a Dakota well approximately $462,000, and to commingle a well approximately $365,000. So we're building the same economic model that we've had in the past and that I've just shown.

In order for a -- With the reserves level that we have, in order for a Dakota well to be economic as a commingle we would have to have approximately 220 MCF a day and those reserves that I show.

Well, if you look at average production back here for a Dakota well, that's only 85 MCF a day. So the Dakota in and of itself is almost to the point where it's not going to be developed because it's uneconomic. You certainly would not, with those standards, go and drill wells.

And again, if you go and look at the next page, if you look at the activity levels in the Dakota, with the exception of 1994, people are not drilling stand-alone Dakota wells. In other words, they are uneconomic. One year that occurred, Meridian Oil and several other operators decided to pursue the Dakota, and the statistics reflect that we were sadly disappointed with the results that we had. In other words, we cannot make money doing that. There have been a couple commingles and some duals, but still the activity level is well less than ten per year.

Over the last six years we have drilled approximately 63 stand-alone Dakota wells. The number of undeveloped drill blocks: substantial amount of undeveloped drill blocks still. At current rates we're developing less than a half a percent per year. The years required to develop all these undeveloped drill blocks is over 200 years. In other words, there's no net present value with the rules as they are right now. There's no net present value in that resource, and the statistics show that people are not pursuing it.

In terms of if we could commingle these, it would cost us approximately $365,000 to develop a commingled Dakota drill block. The total capital required would be approximately $820 million.

When you think about that total capital number, put that into perspective. What that's going to pay for are drilling contractors, completion contractors, completion service companies, salaries for all of their employees. I mean, that's a substantial number in there that's going to go directly into the economy of the State of New Mexico.

The EUR per undeveloped drill block, 729 million cubic feet. The total reserves associated with this asset, approximately 1.6 TCF of gas. Understand, as it is right now, those reserves are uneconomic.

The royalties that would be associated with producing that gas, approximately $383 million dollars of royalties. Ad valorem and severance taxes, $210 million. Operating expenses -- these are going to feed the local economy -- $674 million. And income tax, $300 million worth of income taxes.

Bear in mind, at the current levels, these numbers will never be realized. Unless we come up with another way to pursue this, these resources will never be tapped, or they will be tapped at such a slow rate as to have very little value for both industry and the State of

New Mexico and the people of New Mexico.

Q. Mr. Daves, is -- In your opinion, is there a conservation reason to continue to have an economic standard in Rule 303?

A. No.

Q. Is there any correlative-rights issue --

A. No.

Q. -- involved with that?

A. No, we have the data, we have the ability to allocate production.

Q. Is there any waste issue involved with an economic standard?

A. Obviously, I think our numbers show -- with the current methodology that we have, yes, there is a significant waste potential.

Q. In terms of not getting this resource?

A. Right.

Q. But retaining the rule that says you must satisfy that at least one reservoir is uneconomic serves no purpose, at least in this San Juan Basin area?

A. No.

Q. If that standard -- If an economic standard is left in the rule, do you have a recommendation as to whether the Division -- the Commission, as a matter of policy, could decide that that rule may be deleted for the

San Juan Basin when we look at commingling of the Dakota, Pictured Cliffs and the Mesaverde?

A. Yes.

Q. So if they choose to keep the numerical standard in here -- I mean the economic standard -- this would be a good reference case for those three reservoirs to delete that standard?

A. Yes.

And now we can go back to where I started in terms of the total potential that's out there. Over the past six years we've developed approximately, in a stand-alone drill set of circumstances, only 319 out of 6000 drill blocks, less than a percent per year. And at that rate, you know, it's going to take a long time. In other words, there is no net present value of these resources at the current rates that we're developing them.

Total capital required to commingle development is approximately $1.75 billion worth of capital would be required to develop these. And understand, these would be economic projects if commingled.

The reserves developed, approximately almost 5 TCF of gas. The royalties associated with that, over a billion dollars' worth of royalties. Ad valorem and severance tax, almost a billion dollars' worth of ad valorem and severance tax revenues. Operating expenses, over two billion worth of revenue going into our economy.

And lastly, the income tax is over a billion dollars of income taxes would be fed into the tax base. At current rates we won't get that.

Q. Do you have a copy of the industry's committee's proposed commingling application form?

A. Yes, I do.

Q. It's attached to the -- It's the second-to-the-last page in the prehearing statement, Mr. Chairman.

A. Right, right.

Q. I don't want you to go through it in detail, Mr. Daves, but go through the process of development of the form and talk to us why in your opinion this is going to be a useful standardized form for the industry and for the regulators with regards to taking action on this type of activity.

A. Okay. One of the reasons that this will be a useful form is, it is the only form that is out there currently. We do not have a standardized form.

Typically when an entry-level or a junior engineer comes to me and asks me about, How do we go about filing for a commingle --

CHAIRMAN LEMAY: Where is this form?

MR. KELLAHIN: It was attached to the prehearing statement.

COMMISSIONER WEISS: No, it's not.

MR. KELLAHIN: Here's one.

THE WITNESS: In other words, we do not at this point in time have a form like this, and the methodology used is basically monkey-see, monkey-do. It's what has been done in the past.

I've worked with the Committee to build this form, and it basically meets the data requirements that we've looked at through the Aztec District Office, and looked for the things that are relevant to understanding a commingled reservoir setup.

We basically have an operator name, a lease name, what type of lease is it -- a federal, state or fee -- API number.

And then we start into the primary data block, the name of the various pools for an upper zone, an intermediate zone, and a lower zone, the top and bottom of each of these zones. And understand, this would all be fed into a database so that this data would be readily accessible to anybody that needs to know this.

The type of production, oil or gas, from each of the various zones. The method of production, flowing or artificial lift. Estimated shut-in bottomhole pressure, measured or calculated. This will be a key piece of data over time. That is a piece of data that I cannot stress enough that will be necessary.

Oil gravity or gas BTU content. Current status, currently producing or shut in. If shut in, give date and the rates of the last production. Understand that in the San Juan Basin there are a large amount of nonproducing wells. You know, line pressures have gone up and a lot of these reservoirs will not produce against current line pressures. So a lot of these wells are shut in.

If producing, the rates within -- you know, according to recent tests.

And then the fixed-percentage allocation method. This is the standard allocation method that's used for most commingles today.

Now, item number 9, allocation method if other than fixed-percentage. The allocation method that we've presented in hearings before is more of a subtraction method. In other words, the total production minus the known production equals the production of the other zone. So that would be another way of determining allocation.

Are all working/overriding royalty interests identical in the commingled? We also answer the question, are our interests the same? If not, have we notified those people by mail? We've covered the things that typically go on either in a hearing or in an application.

And then probably the single most important part, are the fluids compatible? By commingling will you not or would you possibly damage these reservoirs? And we give a yes/no answer here. And with that yes/no, in conjunction with that, also an order number. If you have supplied data in a general area -- in reference cases, for example -- then we would refer to that order number so that that data is made available and known where it would be if there is any question whether commingling would damage the reservoirs.

Will the value of the production be decreased by commingling, yes/no? If yes, explain why.

If this well is on state or federal lands, the Commissioner of Public Lands -- kept them in mind, the United States Bureau of Land Management have been notified in writing of this application. So in other words, this is a form that the BLM would probably see and the State Land Office.

And a reference case for exceptions, and -- which -- if there are exceptions in this, which reference case you would be dealing with. And also attachments.

So in other words, this would be our form similar to an APD to pursue commingling.

Q. (By Mr. Kellahin) The Division has developed a database where it tracks production by pool.

A. Uh-huh.

Q. Will the amendments that the industry committee proposes for Rule 303 disrupt or alter the ability of the Division to have that data and correctly track production per pool?

A. Yes, we'll be able to do that.

Q. We'll still be able to continue to do that on a reliable basis --

A. Right.

Q. -- so it would not alter the credibility of their database?

A. Yes.

Q. Okay. With regards to notification, the current rule requires that all offset operators be notified of an application for commingling on a spacing unit that they're adjacent to, either on a side boundary or on a corner, an end corner. What is your recommendation for the Commission with regards to the notice issue?

A. Let me back up. Early in the process of this, we pursued notification rigorously. As time has gone by -- when these ideas were new. As time has gone by, the basic thing that is done with those notifications is, they are put in the trash or recycled. So --

Q. You've never objected or complained --

A. No.

Q. -- with regards --

A. No.

Q. -- to an Amoco notice --

A. No.

Q. -- and vice-versa?

A. We've -- At times when we're partners, we may offer advice and support in how to go about either permitting or allocating production if we have some concern.

Q. And you would be contacted in another method, then?

A. Right.

Q. Do you see any waste or correlative-rights issue if notification is deleted?

A. No.

Q. And your recommendation, then, is to delete the notification of offsets as being unnecessary?

A. Yes.

Q. I believe we've covered the topics that you were going to address, Mr. Daves.

A. Yes, we have.

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

We move the introduction of Meridian Exhibit 1.

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

Some questions of Mr. Daves?

Commissioner Weiss?

COMMISSIONER WEISS: Yes, I have several.

EXAMINATION

BY COMMISSIONER WEISS:

Q. I guess I need to be refreshed before I ask my other questions about why there is such a rule. What was the original purpose of 303? What was it based on?

MR. KELLAHIN: Commissioner Weiss, I'll be happy to give you a copy of the Commission order. I also have the transcript and the rest of that case file. It was Case 4104. It's Order Number R-3845. It was entered in October of 1969.

Basically it addressed a concern by operators that they had a number of dually completed oil wells, and they were getting to the point in the productive life of those dually completed oil wells where they were either going to have to abandon them, and the downhole commingling was a possibility for extending the economic life of those oil wells. And that's how it started.

COMMISSIONER WEISS: Okay, well, that's fine.

Now, another question, more basic.

Why were they dually completed? How come we want to maintain production from only one reservoir at a time? What was the original reason? Does anybody know?

MR. KELLAHIN: I believe it was a regulatory concern, which may be outdated. It was a point in time where they were comfortable with single-completion technology, with dual completion, and they wanted to maintain reservoir management, so that they knew that those hydrocarbons were being produced in a way that they were accustomed to, that there was no inappropriate allocations, that people that owned production in one pool were going to get paid for it, and they could measure it and see it and touch it in a separate stream.

And so I think that was the initial point. It was a management issue.

COMMISSIONER WEISS: Did you say that was in the Thirties in your opening remarks?

MR. KELLAHIN: I said it had been thirty years ago that we developed the rule, so it was. As best I can find, 1969 is the last time this Commission touched this particular rule with regards to its scope.

COMMISSIONER WEISS: Well, as I listen to this, I think that's important, that I understand why we have that rule in the first place.

MR. KELLAHIN: That's where it started.

COMMISSIONER WEISS: I don't have the -- Does anybody have the initial rule? Do we have that available?

CHAIRMAN LEMAY: Yeah, he's got it there.

COMMISSIONER WEISS: Oh, that's it?

MR. KELLAHIN: We have it.

And part of the committee work was to go through those transcripts, and none of our engineers could find a technical basis for the numerical standards.

I understand from Mr. Catanach he's made his own search, and he agrees that there was no scientific basis; they simply developed a set of numbers that have continued to be used.

COMMISSIONER WEISS: Okay, then I have some questions.

Q. (By Commissioner Weiss) What's an undeveloped drill block? Is it an infill well?

A. It could be an infill well, it could be a Pictured Cliffs, just plain, simple Pictured Cliffs undeveloped drill block. It could be a drill block that was drilled and then abandoned.

In other words, there's no production coming out of that hundred and -- In the case of the case of the Dakota, the Mesaverde and the Pictured Cliffs, while the Dakota and Mesaverde are on 320-acre spacing units, the actual drill block is -- essentially, it's 160 acres, and that is what the Pictured Cliffs is too.

So in other words, it's that 160-acre --

Q. Well, let me put it this way: Can a wildcat well be an undeveloped --

A. Yes, it could be. It's not in those numbers, though. Those are the ones within -- The best way to understand that number is to -- Are you aware of what Kendricks maps are?

Q. No.

A. Okay, what Mr. Kendricks does every year, and he has for a lot of years, is, he takes these formations and he plots up in the corner of that section, okay, in the section that would be four drill blocks per se, or four producing wells in any of these horizons. He plots up the cumulative production for that year, for that quarter section, and he also plots a cumulative production for the life of that well.

So in other words, if you took a Kendricks map and just started counting how many of those within where production is, how many of those have no production, have zero production or have never produced at all, currently zero production for a year or years on end, and with that -- what it implies is that that well has been abandoned, but there has been cumulative production out of there, or a quarter section where there has never been any production, and probably a well never drilled.

Q. Okay. Now, on that quarter section --

A. Uh-huh.

Q. -- that you just mentioned are there developed quarter sections around it?

A. Yes.

Q. So this is -- This will apply in my thinking -- correct me if I'm wrong -- to infill situations?

A. Yes, it would. And a good example would be an infill Mesaverde or an infill Dakota where you have a parent Dakota well and then you're sitting there looking at that infill Dakota well --

Q. It's more of a, perhaps, a drainage issue than a pressure issue?

A. I guess I'm not following you.

Q. Well, as I see it, this pressure business that you went through --

A. Uh-huh.

Q. -- which is another question, I see here you have evidence of crossflow, I guess, in your example, the example you have back in the --

A. Uh-huh.

Q. -- section listed "Examples" on --

A. The Reid well?

Q. -- the Reid 19 and the Mesaverde --

A. Uh-huh.

Q. -- do you see how the pressure went up?

A. Yeah, that's -- that's --

Q. I guess that's a crossflow issue. So it's going up?

A. Right. Let's take a minute and walk through this. This is a very good example of how commingling does indeed work, if I can walk you through this and help you to understand this. Would that --

Q. Yes.

A. -- be appropriate?

Okay. What we have here, this first pressure/cum plot is the Mesaverde. And where I've drawn that pink dashed line, that's the last pressure point that the Mesaverde had before it was commingled.

So in other words, what there was before was a dual completion and all these pressures were Mesaverde pressures, and then once we pulled all that out we continued to track that data because we do prorate gas and we do go through that process every year.

But what we did show was, if you go on two pages down, all of a sudden you have the Dakota pressures too. So in other words, these are the pressures in the pressure cum plot for the Dakota.

So what we saw when we continued to check those pressures over time was the effect of both zones being mixed together, and the higher pressures would dominate. That's why you see that jump on the Mesaverde plot. In other words, those points are the same ones on the Dakota curve --

Q. They're the same pressures?

A. Yes, exactly. So in other words, if we were to back up in time -- this is a material balance methodology here -- we can look at the Mesaverde and see that we should get approximately 450 million cubic feet of gas out of that. Do you follow with me on that very first plot?

Q. Uh-huh.

A. Okay. And we're ignoring those last data points, because those are -- in terms of pure Mesaverde production they are invalid. Okay, are you with me on that?

A. Uh-huh.

Q. Okay. Now, if you look at the Dakota, and the same methodology went on here, that last pressure point -- that pink line was the last pressure point before the Dakota was commingled with the Mesaverde, and then all the points after that are the combined function. Okay?

If you add up the gas that's associated with both of these, you should end up now with a combined total of approximately about a half -- 1.6 or 1.7 for the Dakota and approximately 480 for the Mesaverde.

So in other words, the new material balance plot should reflect what the remaining reserves are for both reservoirs. Are you with me on that?

In other words, those pressure points -- It's like you have your two tanks there. Now that you've turned the valves on and hooked it up together, as you deplete those two reservoirs, they're -- all of a sudden, a new relationship is going to be formed --

Q. Is that in here?

A. Pardon me?

Q. Is that cumulative --

A. Yes.

Q. -- of the two zones together in here?

A. Uh-huh. If you go down to -- I believe it's the sixth plot -- what I've done is, I've started a new zero point. And now we're tracking the total remaining reserves for our new reservoir, which is the combination of the other two.

And strangely enough, if you go through the mathematics of this, it does match up, which -- in theory and in reality it should. There's no reason why it shouldn't.

So in other words, what we're seeing with the Mesaverde is, there's approximately -- of producible reserves, 395 million cubic feet of gas remaining. For the Dakota by itself, there's approximately 1.5 BCF of remaining gas -- Well, excuse me, the remaining would be 133 million, for the Mesaverde would be approximately 75 million cubic feet of gas.

So if you look at the total cumulative plot, the last one, if you add the two together, that's approximately what you get, and that fits very nicely with the decline of the overall reservoir.

Is that --

Q. Yes.

A. I fear I'm losing you on that, and I don't want to do that.

Q. I heard you.

A. That's a very key, important point because the theory says it should work, and you have an example of reality here where it does work, very clearly.

Q. I had another question. I notice that it costs less to drill deeper.

A. On a footage basis?

Q. Yeah, or something.

A. Yeah, typically --

Q. I didn't understand that.

A. That -- On a per-foot basis it would, and that reflects the drilling contractor's willingness to be on that location longer and not have to move --

Q. Maybe just -- Just help me on one of those.

A. Okay.

Q. I didn't follow it.

A. Let's look at the Dakota first, and then go up.
Q. Just any one of them.
A. Okay, let's look -- The Dakota costs to drill a Dakota well to TD as a stand-alone --
Q. Yeah, okay.
A. -- would cost approximately $542,000 --
Q. Just the drilling costs.
A. The drilling costs.
Q. Yeah. It's $300,000 for a single completion, a dual completion is $217,000 --
A. Uh-huh.
Q. -- and then it goes down some more for a commingle. I don't understand that.
A. The drilling costs associated with a single well would reflect to drill it, to run the casing, to cement it. Those would be your drilling costs.
Q. Okay.
A. Okay? Now, in terms of how that cost is allocated, on a stand-alone drill well, the Dakota formation would bear the cost of all of that.
A. Okay.
Q. Okay? On a dual, down to the point of the shallower horizon, there would be a 50-50 split of cost.
A. Okay.
Q. And from that point on, the Dakota would bear all

of the cost.

Q. Okay, I follow you now. I couldn't see how --

A. Yeah, I anticipated you might ask something like that. Learning that process took me awhile, so I understand your confusion.

Q. And a last question. What was the -- Not my last question. What was the gas price used to develop your economic?

A. Approximately $1.20 per MMBTU.

Q. Okay.

A. And for conventional gas, that's approximately what is being realized out there on the market right now.

Q. And then did you consider as a method for permitting commingling a -- new wells -- or anyway, just well density? It seems to me that it would be -- where you have a lot of data and a lot of control such as you --

A. Uh-huh.

Q. -- presented here, that experience and expertise is sufficient to assure that you know how much gas is in place and you can make proper calculations as to --

A. Uh-huh.

Q. -- recovery and such. But in areas where you don't have that type of data, which is what you get drilling wells, it may be more difficult. And that was my question earlier about a wildcat, something outside the blue there.

A. Right.

Q. I take it, then, the blue area here there's a lot of wells?

A. Right, and a lot of undeveloped drill blocks too.

Q. Yeah, but the undeveloped drill blocks have sufficient data from wells around them?

A. Right, you have significant control.

Q. The control is good, and there's probably -- perhaps there's no need for any rules governing commingling in that blue area?

A. Correct.

Q. So my point is, you have some other, more complicated -- in your summary, whatever it was you were saying you -- What were your examples?

A. I have one for the Dakota --

Q. What -- The rules you want?

A. Oh, oh, yes, let's go back. The rule in terms of crossflows?

Q. Whatever rules you want this area commingled.

A. Okay, probably the most important two rules that I see, I would like them to stay the same.

Q. And this is in -- Where are you at?

A. The pressure crossflow part. And basically what I stated here is how these rules apply to the mathematics and physics. And what I'm basically saying is that the rules that we have that protect the permeability of the reservoirs --

Q. Uh-huh.

A. -- essentially do not let fluids mix that would damage the reservoirs or the fluids damage -- or the fluids create precipitates amongst themselves.

So that's what these two rules say. I wholeheartedly agree with these rules. Whenever --

Q. Well, my concern would be, if we deleted the bottomhole pressure requirement -- Let's say you drilled a well between those two blue areas.

A. Uh-huh.

Q. Well, you don't have any information.

A. Uh-huh.

Q. And you went in and you drilled that on the premise that you're going to commingle it, and you found for some reason that pressures there were original or something in one zone and not the other.

A. Right.

Q. I don't think that should be permitted, because you won't know what the original gas in place is, you won't be able to measure it or determine it or rate it.

A. Right. Let's put part of this into perspective, though. Just because they are not within the blue -- If they were economic to have developed those areas, I would suggest that they would have been developed.

Q. Okay. Well, my point is, if we limit it to geography, rather than -- and geography being where there's adequate well coverage --

A. Uh-huh.

Q. -- we don't have to worry about pressure.

A. Correct.

Q. But in areas where you don't know what pressure is going to be, I think we do have to worry about --

A. Right, and that's where this rule -- where I have defined the rule the way, as an engineer, I think that rule ought to be in terms of, the pressure of the higher-pressured zone should never exceed the original pressure of the lower-pressured zone. That would apply either in the blue or out of the blue. It -- that's just --

Q. Yeah, but how are you going to know what -- You come in and you request to drill a well in the white.

A. Okay.

Q. Okay? But you come in and all your economics are based on a commingled situation.

A. Uh-huh.

Q. And you come in there and you find original pressures in both of them, and that was the reason you drilled the well.

I don't think that's right, because you won't know the gas in place in those two reservoirs, either of them. You won't be able to determine it because you won't measure it. It's all -- You don't have to do anything, you'll just go drill the well.

A. And that would probably be a good example of an area where you are in a wildcat area, and this could apply for southeast New Mexico as easily as the San Juan Basin. Do the proper testing, find out what the parameters of the reservoir are, then pursue the commingling in that respect.

Q. Yes.

A. But this standard here --

Q. But on the infill areas I don't think it's necessary.

A. Right, but this standard here, this pressure standard that I'm recommending we adopt, would apply either in a wildcat case or in an infill case. It's the same set of rules that nature has provided for us.

Q. I'd have to give that some consideration. Just sitting here thinking about it, I don't -- I'm concerned about that.

A. Well, let's flip that around just for a second, if I might.

The 50-percent rule, there's no technical merit associated with that 50-percent rule.

Q. Well, there's -- That, I'm not sure of. That's in that -- I haven't read the --

A. Uh-huh.

Q. -- why there's a --

A. Right.

Q. -- 50-percent rule. I don't know --

A. But --

Q. -- what's going on.

A. -- the flip side to that, again, is, Mother Nature has provided us with standards, we've measured these standards, we know -- Typically in any gas reservoirs, we know what original reservoir pressures are. So we do know that, and we --

Q. Not in any gas reservoir. You drill one in the white that you've never tested before, you don't know what the --

A. First thing I'm going to do as a reservoir engineer, when I drill into an undeveloped area, I want to know that pressure. That is the key piece of data --

Q. Precisely.

A. -- that you have got to have.

Q. Precisely.

A. So why would you not want to take that data?

Q. My concern is, if we do away with pressure rules they'll never be measured.

A. That rule is still required in the Dakota, in the pool rules, to take that original reservoir pressure. That's just the normal course of business, that should be done.

Q. Okay.

A. But that doesn't affect this rule, is my point. That data -- How could you know what that higher pressure is --

Q. -- unless you measure?

A. -- unless you measure, exactly. Data gathering should continue. Just like with the case of this Reid well, although it is commingled we have continued to keep those pressures, track those pressures over time, and that verifies -- and it did a very nice job of verifying that, one, there was no waste and, two, that our allocation method is fairly sound.

Q. Yeah, it does that.

A. Yeah, so -- yeah, I mean -- But that's a function of gathering data. When I look across the border into Colorado, I don't see that --

Q. That's the situation I want to avoid here.

A. -- rigid standard.

Yes, and New Mexico has done a magnificent job of doing that. But those are proration rules that have driven that process, not commingle rules.

COMMISSIONER WEISS: All right, that was the only questions I had. Thank you.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Incompatibility of fluids, is that a generalized type of situation? Can you say that in most cases PC fluid is incompatible with Mesaverde, or is this a regional or an area, or is it done well by well?

A. It's done on an area basis, typically. You may look at a nine-section area, check the fluids that are produced, check the compatibilities over a broader area.

Q. Okay, but that requires compatibility analysis for all nine of these wells then?

A. Or the fluids produced out of each of -- Say you have five Pictured Cliffs wells and five Mesaverde wells. You would gather fluid data out of each of those and then run the analysis to compare what the fluid components are and if there would be a compatibility problem.

We would typically do a fairly reasonable study in trying to determine that, because it makes tremendously good sense to us as an operator and the people that make a living off producing this not to allow damage to occur to those reservoirs.

Q. Of course. I'm nervous about the reference well that's chosen and how do we know the parameters that surround that area? How do we know how to make the parameters, the boundaries of that area, if we're just choosing one certain reference well?

A. The limits are going to vary, based off of the parameters of the reservoirs. If we know in a general area -- The Fulcher-Kutz Pictured Cliffs is a good example. It's a pool, per se, that stretches out over probably 30 miles laterally and about three or four miles across.

Okay, if you look on this end of that pool and test the gas and the fluids, typically it doesn't produce any water anyways. So you would -- You know, right there, you know there's not a fluid-compatibility problem because it doesn't produce water. And if you were to commingle that, say with the Fruitland Coal, the Fruitland Coal in that general area does not.

I mean, it requires some engineering judgment to define where that is. But typically when our people that are pursuing commingles pursue them, before they would even fill out this application, we would want to know internally what -- the level of detail they're studying so that we would be convinced, before you would ever even see this form, that what we're wanting to do makes sense, because we're the first ones that don't want to wreck the reservoir. It doesn't do us any good to do that, so we

would pursue that.
Q. But you would say that pools have certain characteristics that would render them incompatible?
A. Uh-huh.
Q. All right. So you take it to the pool basis rather than an area basis?
A. It would typically be on an area or a pool basis, depending on where you're at within the state.
Q. Just some clarification on some of these economics. We might as well go to the summary --
A. Okay.
Q. -- portion.
Are these figures based on Meridian's holdings within the blue area? Are they based on basinwide --
A. Basinwide.
Q. Basinwide?
A. Yes, ma'am.
Q. Okay. And are they strictly Meridian, or everyone else included?
A. Everybody, everybody.
Q. Okay. Down on the royalty line, is that a very optimistic figure based on the fact that all of these would be producing from 12.5-percent lease spaces acreage?
A. That was an assumption I made --
Q. Okay.

A. -- for ease. I mean, you know, there were a tremendous amount of cases that were involved in this, and typically what we see is a one-eighth royalty. On a --

Q. But that's going to be --

A. Fairly consistent. I mean, that's --

Q. -- fairly consistent.

A. Yes.

Q. But it's also going to be decreased significantly if the wells are on federal land?

A. No, that would be a standard federal royalty lease, is 12.5 percent.

Q. Okay. But New Mexico only gets half of that?

A. I'm not -- What I'm using here in terms of royalties is, in my model I assumed that I would own 100-percent working interest in the well, or whoever the operator would be, and that they would own an 87.5-percent net. In other words, they would own seven-eighths of the production, and the other eighth -- This is what this reflects, is that other eighth of production.

Q. Okay, and that's significantly decreased on federal lands and totally decreased on Indian lands, correct?

A. In other words, in terms of what the State of New Mexico would realize?

Q. Right.

A. Correct, right, and what -- That's true. In other words, those would be royalties that would be shared between the states, federal government and the Indian tribes. But that's the sum of it. How that gets split out would be a case-by-case basis.

Q. Are you aware that this form that you've submitted does not meet Land Office requirements by rule?

A. No. But what would --

Q. Since it doesn't, do you consider it premature, so that --

A. It's --

Q. -- operators would not have two separate forms?

A. Correct, it's a prototype at this point. What data that you would require to enable us to use a form for both -- for both the state and the federal government and to meet all state requirements, there would obviously be some considerations included in this that would reflect your needs.

Q. Okay. So it's premature for the Commission to consider this form in its present state as the form that you would like to see ruled on?

A. I'd like to defer that to Tom, I think.

MR. KELLAHIN: Mr. Daves is correct, it's a prototype, and as I told you in my opening statement, it had not been submitted nor approved by the Land Office. It meets the requirements of the BLM and the OCD at this point, and it's a topic for discussion.

Obviously, we would like the Land Office to agree to this form and modify it accordingly, but we are at the point of presentation where we thought it necessary for you to see the form as it has developed. But you're right, it may need further refinement to satisfy your rule.

What we may ask the BLM to do is modify their rules. You may find that the Land Office rule is the rule that needs to be modified to accommodate this form. That's a topic for discussion.

You would not expect the Land Office never to change their rules to allow us to uniformly use a common commingling form?

COMMISSIONER BAILEY: I would not expect any quick action on that, since our commingling rule was already modified this past summer, and it is a very lengthy process for the Land Office to change those rules. It is not something that I would personally expect to be done in the near future at all.

MR. KELLAHIN: Well, we've spent seven months on this process. I'm sure we're willing to continue to work with the Land Office to get a form everyone is satisfied -- And if it doesn't meet your needs, then we have satisfied a substantial problem with the BLM and we'll simply have a duplicate process for a while.

But in terms of the OCD's approvals, we think it satisfies their needs. They've told us they like our form, and we hope that we can convince everybody to use them.

COMMISSIONER BAILEY: I would hope that we would be able to come to some sort of understanding so that there's only one form that would be required from industry, rather than two separate processes.

MR. KELLAHIN: That would be our hope too.

COMMISSIONER BAILEY: That's all I have.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Daves, your -- Well, I guess my question in a nutshell, bottom line is, will the currently developed wells in there drain the remaining reserves?

The assumption you used, I think, is that it won't because all these dollar figures are based on recoverable reserves from new wells. But will the remaining wells that are in these fields now eventually drain only -- It may take 300 years, and your argument is, time-value of money, rather than not getting that money at all?

A. To stretch your question even further, in theory, one well should be able to drain all of those reservoirs. But the benefit by doing that would be nominal. And indeed, the benefit of where we're at now would be nominal.

So in other words, it would -- It is a time-value-of-money question but, in essence, where is that proper line, I guess, is my question.

We do need to ensure that, one, we can meet our market demands, two, that we meet the demands that we have within the State of New Mexico to utilize this resource to fund whatever we need to do over time. And if it took several hundred years to do that and each year we were losing production, then I would suggest that the value of that is going to depreciate fairly quickly.

Q. You're familiar, as well as anyone, that certain of our consumers, especially California, have used the San Juan Basin as a gas-storage reservoir. So you know, people pull out of it and drill wells when they need the gas and they feel the price of gas is high enough.

A. Uh-huh.

Q. It's been that kind of a deal, not necessarily a situation where people want to maximize their cash flow at any given time.

I mean, that -- I think with the assumption that a dollar 200 years in the future has no value today, these figures are certainly acceptable. But you're right, one well could drill it all --

A. Uh-huh.

Q. -- drain it all. And this may be a question that everyone might want to address. If we're looking at, and I think we are, initially at reference cases --

Q. Uh-huh.

A. -- one of the threshold questions is, whether the Commission addresses this in the San Juan Basin now or an Examiner hearing will address this issue later on in another commingling situation, is, how far can we extend data under one order?

A. Uh-huh.

Q. I think that was -- We've referenced briefly with some of the comments my fellow Commissioners made.

You're talking about a pool or an area basis --

A. Uh-huh.

Q. -- the idea being, each formation may be somewhat unique, and as far as fluid characteristic change -- I mean, does -- Example: Does the fluid in the San Juan Basin change over five, ten, fifteen, twenty miles, or can you project it with some degree of certainty over that distance?

A. In terms of fluid compatibilities, that's an issue that probably needs to be looked at fairly closely in any given area.

I think, one, if the engineer is going to come to you with the commingle recommendation and an application, he's done that, he has looked at that. Now, how far he wants to stretch that reference point is a function of how in depth of a study he's made for that specific set of data.

But in terms of crossflow pressures, this is a good medium right here for a reference case in terms of how we define what our standards are in terms of pressures.

Okay, so in other words, what I'm saying is, in the cases of compatibilities and reservoir damage from fluids, that needs to be a much tighter controlled issue.

But the issue of the 50-percent rule and how we define that pressure part, this is -- right here and right now is that point in time.

Q. Would you make a recommendation that -- in terms of fluid compatibility, that each well, even though it is drilled under an existing commingling order, tests fluid compatibility, would you say, on a well-by-well basis?

A. No, I don't --

Q. So you can extend it beyond one well?

A. Oh, yes.

Q. But how far you extend it is somewhat of a nebulous call at this point?

A. It's going to require the engineer to look at the area and understand that area in terms of fluid compatibilities.

And in the areas that I've testified in the past, I was familiar with the area, I was familiar with the gases that were produced, I was familiar with the fluids that were produced, and I set my limits and I came back with hearing data to support general areas. And it may have been as small as four or five miles in a radius-type area, but I did not try to stretch that clear off to somewhere else.

It's foolish to do that, in my opinion. You need to look at a general area and find out what's there. And that would probably be the primary driving point of reference cases in the San Juan Basin at this juncture.

Q. In terms -- You've addressed the three main producing zones; you haven't addressed the coal seam wells.

A. Uh-huh.

Q. Would that be something you'd throw into this mix for --

A. Yes.

Q. -- commingling?

A. Yes. Yes. And the Fruitland Coal is a very nonhomogeneous reservoir. You have the prolific zone where it produces a high -- a 10-percent CO_2 and water.

When you move down into the areas where I've testified in the past, the gas is, strangely enough, very much like the Pictured Cliffs gas, and like the various reservoirs down there. I mean, it's a high BTU gas, no CO_2, almost no water production. So in other words, the minute it comes out of the ground, it's pipeline-quality at that point in time. And the pipeline gathering companies recognize it as such.

Q. How many zones have you commingled, has Meridian commingled in one wellbore?

A. In one wellbore, I think the most that we've seen is -- what? Three?

MR. ALEXANDER: I think so.

Q. (By Chairman LeMay) So you've got some Pictured Cliff, Mesaverde and Dakota, the three are commingled?

A. Uh-huh. I think the first map I showed shows the relative location of this.

Q. Without any mechanical problems you've run into that --

A. Correct, correct. And quite honestly -- I keep referring back to this case, the Reid 19, the example case. It's a marvelous example of how well this can work if done properly. Their engineer obviously looked at it, understood the fluids, he was able to make an allocation that made good sense.

And the beauty of it was, we continued following our proration rules and continued to gather pressure data, so that we not only had what the Mesaverde reservoir was, what the Dakota reservoir was, but also now with the new reservoir, what the mix was. And then -- that makes good engineering sense.

And in the future as we look across the San Juan Basin for new projects, that data will be critical. So those proration rules have done something serendipitously that they weren't intended to do initially.

Q. For proper allocation would you recommend yearly tests?

A. No, I don't think that's necessary.

Q. But the proration rules as they're currently constituted give you frequency-of-test information that's adequate --

A. Uh-huh.

Q. -- for allocation purposes?

A. Correct.

CHAIRMAN LEMAY: That's the only questions I had.

Do you have --

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, I had one more concerning this issue of correlative rights in a vertical sense --

A. Uh-huh.

Q. -- and that's the crossflow issue.

A. Uh-huh.

Q. Is that -- Who owns, generally? Is it common ownership, or do the same people own the same portion of all three zones?

A. Yes and no. Sometimes they do, sometimes they don't.

One good example where we've struggled in the past is with the Pictured Cliffs and the Fruitland Coal. The Pictured Cliffs is based on 160-acre spacing and the ownership is based on 160-acre spacing, whereas the Fruitland Coal is on a 320-acre spacing. So this person that has a fixed percentage in the Pictured Cliffs, if he has the same lease position in the Fruitland Coal, now his interest is cut in half, because it's gone to a 320-acre spacing unit?

Q. Right.

A. And it's allocatable.

Q. Well, with that in mind, I think the notification process has to be included so that --

A. But we do that to the interest owners, and we will continue to do that.

Q. That's important.

A. Yes.

Q. I don't think we can delete it from any order.

A. No, but what we are saying is, the offsets now, we've found that that's essentially a waste of time. We keep track of what they're doing in other ways, so that the notification process is --

Q. You do. Do the -- Who else operates in there? Maybe the Jicarillas?

A. Yeah, yeah.

Q. Do they do the same thing?

A. Jicarilla tribe?

Q. Yeah, do they operate there? Or somebody like that, some smaller operator?

A. Well, I couldn't answer that question.

Q. Well, that's a concern.

A. I guess -- Let me try and understand your question.

Q. Correlative rights in a vertical sense.

A. Uh-huh.

Q. That's the question. How do you protect those?

A. By proper allocations.

Q. Yeah, you guys do that, but how does a smaller guy do it? I mean without notification. I don't care whether -- You know, I don't care who does it. But if someone wants to object who's in this 320-versus-160 --

A. Uh-huh.

Q. -- situation, he ought to know what's going on, that the well is going to be commingled.

A. Well, he would be notified. If he's --

MR. KELLAHIN: May I respond? I --

THE WITNESS: Yes.

MR. KELLAHIN: I can see you're talking two different things.

The rule that you adopted in September continues to require, and we are continuing to propose, that everybody internal to the spacing unit that's affected and shares in that production gets notification if there's differences in ownership.

COMMISSIONER WEISS: But you're talking about -- I'm not talking about offsets, I'm just talking --

MR. KELLAHIN: That's right, those people continue to get notice.

COMMISSIONER WEISS: Good. That was my last question.

CHAIRMAN LEMAY: Commissioner Bailey, anything else?

COMMISSIONER BAILEY: No.

CHAIRMAN LEMAY: Mr. Carroll?

MR. CARROLL: Yeah, Mr. Chairman.

EXAMINATION

BY MR. CARROLL:

Q. Mr. Daves, if I could just clarify one point. Other than your proposed revised pressure criteria, there really is no criteria that would prevent any well in the

San Juan Basin, to be drilled or existing, from qualifying for downhole commingling; is that correct?

A. Can you state that one more time, make sure I understand it?

Q. Other than your proposed revised pressure criteria, which is revised from the 50-percent rule --

A. Uh-huh.

Q. -- there really is no criteria that would prevent any well from qualifying for downhole commingling?

A. As the rules are stated now, for instance, you could not -- I guess between the four -- If you were, say, to want to commingle two economic zones that you had defined as economic zones, you could not commingle them now. You would have to separate the two.

So if there were two zones in there that were economic, you could not commingle them as the rules are stated right now.

Q. I guess to rephrase it, the only test you have that would disqualify a well from downhole commingling would be the pressure test, your proposed revised pressure test; is that right?

A. Correct.

MR. KELLAHIN: Well, you have a fluid test.

THE WITNESS: Oh, and fluid compatibilities, absolutely. Thanks, Tom. Fluid compatibilities would be the most important.

MR. CARROLL: That's all I have.

CHAIRMAN LEMAY: Additional questions? If not, you may be excused.

Shall we break for lunch, come back at one?

(Thereupon, a recess was taken at 11:48 a.m.)

(The following proceedings had at 1:05 p.m.)

CHAIRMAN LEMAY: Okay, we shall resume.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

Our next presenter is Pam Staley. Ms. Staley is a petroleum engineer with Amoco. She resides in Denver, Colorado.

PAMELA W. STALEY,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Ms. Staley, for the record would you please state your name and occupation?

A. My name is Pamela W. Staley. I'm a petroleum engineer employed by Amoco Production Company in Denver, Colorado.

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

A. No, I have not.

Q. Summarize for us your education.

A. I have a bachelor's of science in geology from Southern Methodist University in 1978, a master's degree in geological engineering from the University of Missouri at Rolla in 1980.

Q. Summarize for us your employment experience.

A. I was employed by Fugro Gulf, an offshore consulting firm, for a year and a half after receiving my degrees, and then I went to work for Amoco Production Company in late 1981 as a petroleum engineer, and I've been employed by them since then.

Q. You'll have to raise your voice. There's a hum of this fan over our head. The microphone won't amplify your voice either, so --

A. Okay.

Q. -- if you'll speak up for us.

Describe how you were involved as an engineer for Amoco with regards to downhole commingling applications.

A. For the past year and a half I have been filing all of the applications in New Mexico for Amoco in downhole commingling, assembling the information as well as filing the applications.

Q. Have you participated with the industry committee the last six months in examining the various issues involved in Rule 303?

A. Yes, I have.

Q. And based upon that participation, do you now have conclusions and recommendations for consideration by the Commission concerning these rules?

A. Yes, I do.

MR. KELLAHIN: We tender Ms. Staley as an expert witness.

CHAIRMAN LEMAY: Her qualifications are acceptable.

Q. (By Mr. Kellahin) I'd like to start with the handouts, Ms. Staley. If you'll take a moment, let's look at the first handout and have you begin by summarizing for us Amoco's downhole commingling activity up to today's period.

A. Yes, the first slide that I have in my exhibit is a slide showing the downhole commingling that we have done to date. You'll see that we have commingled 81 wells. They are color-coded.

We have done a variety of formations, as you can see, with the predominance of our work in the Dakota-Gallup comminglings, as well as Dakota-Mesaverde comminglings.

Q. Are you in agreement with Mr. Daves about the usefulness of having downhole commingling as an operator's choice for additional recoveries out of the San Juan Basin?

A. Very much so.

Q. Was there any part of his technical presentation or his comments or conclusions with which you have disagreement?

A. No, none.

Q. Let's talk about what you forecast from your point of view in doing all these kinds of applications for your company, as to what that activity is going to be in the future.

A. The next example in your packet shows the 1996 San Juan Basin plans for Amoco. "DHC" is downhole commingling.

We plan to downhole commingle at this point 45 wells. That's a fairly large amount of wells for us to start the year with. We anticipate that the inventory will grow steadily through the year over that, and we would probably anticipate at least doubling that activity in 1996.

Drilling activity, our opportunities have been reduced in drilling. Our budgets and capital constraints have caused us to look for other ways to find reserves in the Basin. And in 1996 we anticipate our drilling activity to be down to one rig, which is a significant reduction for us.

We will use those rigs to access locations, hopefully, that would be otherwise undrilled. And by saying that, I'm looking at some of Mr. Daves' types of locations where we would hope to access more than one formation in the wellbore.

Our activity level, we see being much more in the commingling and workover activity this year, and not nearly as much drilling.

Q. Do you have another slide that also shows this in a different format?

A. Yes, specific to downhole commingling you can see we're moving on the next exhibit to a little bit different activity. We'll be doing more Dakota and Gallups and more Dakota-Mesaverde, but then we'll really be moving into PC-Mesaverde and Chacra-Mesaverde as our two main formations. At least that's what we see right now.

Q. Can you summarize for us Amoco's position with regards to what you see as the benefits of downhole commingling, particularly for the San Juan Basin, which is your frame of reference?

A. Right. Well, the downhole commingling for us is a way to help stabilize production. It is a way to often help our older wells do better.

You'll note that many of the formations that we are dealing with commingling have some liquids, and often the liquids are assisted in lift by some of the gas formations later in life.

We see a lot of logging off of our wells, and we've seen the commingling help this substantially, and I'll have some examples later for that.

Q. Have you also examined the opportunity for what I've characterized earlier as new drills?

A. Yes.

Q. You will have areas within the portions described by Mr. Daves where you also could justify a well based upon the economics of a new drill as a commingled well, and that is the only way that well might be drilled?

A. That is correct. We're always examining ways to find more drilling opportunities out here, and we're finding to compete with moneys elsewhere in our company that we're having to -- hope to add zones here to get more production out of these wells to make them compete economically.

So as we are able to move into areas and stack pay and make a better well out of our drilling prospect, we'll be able to drill more wells out here.

Q. Were the kinds of pressure ranges that Mr. Daves described when he's examined the Pictured Cliffs, Mesaverde and Dakota characteristic of the types of pressure you're seeing for your wells?

A. Yes, absolutely. They're very close. And what we have seen -- They vary a little bit across the Basin, of course, but they're very consistent with what we have seen in our wells.

Q. So there was nothing in his technical presentation, then, that was unique to Meridian?

A. No, not at all.

Q. It would be characteristic of these particular reservoirs in the San Juan Basin?

A. Yes, and his exhibits incorporate Amoco wells across the Basin as well.

Q. Let's go to some of your examples. I've asked you to bring some examples of well performance before commingling and then what has happened as a result of commingling. They're attached as your next displays.

If you'll turn to those -- And I don't expect you to talk about each one of them, but find one that you like as an illustrative example, and let's describe it for the Commission.

A. All right. Well, the first one is a good example.

Q. This is the Jicarilla B 1?

A. It is the Jicarilla B 1-8 1E-7E and 8M.

This well -- Just to give you an idea of how this is laid out, the two curves on the right side are the individual curves prior to downhole commingling. The curve on the left side of the example is after commingling.

Q. We look at this display, the top curve on the upper right has got a code that's a Mesaverde?

A. That's correct.

Q. And then the bottom --

A. -- is the Dakota.

Q. -- right is Dakota, and then over on the left is the commingled stream?

A. That's correct. And as you can see, that particular well had quite a bit of loading up and down time. That's evidenced by the very erratic nature of the curve on the right. And we had that occur both in our Mesaverde and our Dakota production.

Q. What's causing that?

A. In the Dakota case, it's just some down time related to operational issues. In the Mesaverde, it was related to some of the liquid loading that we had.

And when we combined those two for a downhole commingle in 1992, you can see that we got a little bit of increase in production, and then we stabilized back into a decline which is very similar from what we anticipated from the two wells.

I've equated that -- The way I've drawn these angles is to equate that to a 1995 date and then look on both curves out to see what we would have produced at that decline out in 1995. So that's how I've determined what we would have gotten out of those wells compared with the commingled case.

Q. You've linked, then, the economic life of the well by commingling?

A. That is correct. We believe that by stabilizing that, we have much less down time. We've also been able to reduce our costs, because in many of our cases such as this we've had a dually completed well, we've been able to remove downhole obstructions in the way of piping, we've been able to reduce the number of surface facilities that we have, so we have less workovers, less down time, less surface equipment. All of that affects your cost. And long-term, that gives you more reserves in your well.

Q. Ultimately this increases ultimate gas recovery out of one or both of these reservoirs, does it not?

A. That is correct.

Q. Now, let's talk about the liquids. Are you talking about hydrocarbon liquids?

A. Both hydrocarbon and water, so it can be either one. In some of the later examples that I have where it's Gallup, it is more oil-type liquid rather than --

Q. Do you agree with Mr. Daves that if you're looking for a conservation or a regulatory flag by which to process and approve commingling, one of the important engineering issues is the fluid-compatibility issue?

A. Yes, sir.

Q. Describe for us why that's important, how often it is, in fact, a real problem, and how you recommend the Division address that issue.

A. As a reservoir engineer, I believe that it's a very, very important issue. However, Amoco has not seen any wells out here that we could find that have had incompatibility problems.

In our process, in going through our downhole commingling, we collect that information and we take a look at the compatibility of the fluids, and we just haven't seen any to date. Nor have we in our normal operations, where those fluids are commingled at surface and those sorts of things. We've not seen a significant problem in the formations that we're working with in the San Juan Basin.

So I would say that while it's a -- something that a reservoir engineer is very concerned with from a practice standpoint, and we do fully concur with continuing to do just as we've always done, which is why we want to keep the rule the same way in this area. But we just -- We've not seen a significant problem out here, but it's always good to check.

Q. All right. It continues, then, to be your recommendation that the practice we have established under this rule would be unchanged, and in fact this portion of the rule remains unchanged?

A. That is correct, and Amoco would not recommend changing that part of the rule.

Q. All right. In terms of Amoco's success and your confidence in your company's ability to accurately allocate production, what opinion do you have?

A. Well, these are very long-lived formations. We have a lot of historical data out here. We typically have wellbores very close by in similar formations, and we've found it's very easy to allocate.

We also have several wells where Amoco's planning on going from a dual completion to a single completion. And we have that historical situation, as Mr. Daves did in his Reid well, where we can estimate what the production is going to be and then actually compare and see how it's done afterwards. And some of these examples show that, and we feel that we are able to allocate very effectively.

Q. All right, let's go through some more examples. We've looked at the first one. Show us another.

A. The second one is a very flat well, I would say. This is the San Juan 28 and 7 unit, Number 76. This well is now operated by Conoco and was downhole commingled during Amoco's period as operator on this well.

Again, looking at the two curves on the right-hand side, which the top is a Mesaverde curve, the lower one is a PC curve, and as you can see there, both of those wells again have a lot of logging-off problems, a lot of down time. In the case of the lower one, the PC well, very low production and logging off due to fluids.

When we combined those, the result was very similar where we got very much what we anticipated to get in this well, and we were able to reduce after 1992 the amount of down time that we had in this well on a regular basis.

Q. Do you recall whether or not these examples were all processed using the Division's administrative approval procedures for commingling?

A. The examples that I have here, yes, were.

Q. These are not examples where you were required to take a commingling case to hearing?

A. No.

Q. All right. When we look through these examples, wherein do you see the opportunity to improve the existing rules so that we might more efficiently administratively process the commingled applications?

A. For myself, I think the main issue that I've had with this is the amount of data that we're having to collect and provide and the manner that we're providing that. I think the form will be a very great help to us in consistently gathering the information and putting it together.

From Amoco's standpoint, we have had several that have had to go to hearing, predominantly because of the pressure rule. I have had wells that have not met the pressure rule, and so we've had trouble producing those and have had to wait until they have met the pressure conditions.

So I would say those are the main parts that affect us.

Q. Do you share Mr. Daves' technical conclusions with regards to the pressure rule --

A. Yes, I do.

Q. -- that you agree with him you don't see a reasonable regulatory reason for a 50-percent component to the pressure rule?

A. I agree. I find that part of the rule to be somewhat frustrating, because you can commingle a well that is a 2000-pound to a 1000-pound well, but if I have a 450-pound well and a 250-pound well, can't do it. So that just doesn't make very good sense. We're not protecting what we need to be protecting.

Q. Let me hand you a copy of the Commission order where they amended the rules back in September, and I want to look at the Exhibit A that's attached to that order and deal specifically with the topic on the second to last page where we talked about the gas-gas duals.

A. Uh-huh.

Q. And that's really what you're doing, isn't it?

A. Right.

Q. Walk us through the process. This is something that's a major responsibility for you to do. I walk in and say, Ms. Staley, I've got a well I'd like to commingle. It's an existing wellbore, it's a gas-gas. Please help me do it. Here's the rule. Walk us through what you do.

A. Okay. Well, I first give them a list of things that I need, which is pretty overwhelming for most of my engineers, that they need to gather the data to supply.

The first thing that we look at, of course, is the economics to determine whether or not the well meets the economic criteria, and that throws out a lot of our wells, and so we're not able to do those things on many of our wells because of that.

Q. Let's stop at that point.

A. All right.

Q. The Division, in response to the industry committee's request, has proposed that this particular paragraph be modified and that the phrase, "not otherwise be economically producible" be stricken, and the substituted phrase is that at least one zone is marginal. You understand the proposal?

A. Yes.

Q. Comment on that. Is that going to be useful when you make decisions about the opportunity to commingle wells?

A. Certainly, that will increase that threshold and give us the ability to do more wells.

However, it still restricts me, often, from doing -- You know, commingling wells early in their life, such as some of these examples which would have been helped much earlier in the life of the well and stabilized much more if we could have commingled them earlier on.

So while it will help, I think we still will have wells that we cannot commingle that probably operationally could be helped by that.

Q. From your perspective do you see any regulatory reason to have this economic rule for gas-gas commingles?

A. Not for gas-gas, no, I do not.

Q. In the absence of that rule, would you as an offset operator -- would you be concerned that somehow that commingled well would have an advantage over your wellbore in an offsetting spacing unit?

A. No, and in fact, the offset operator, notice at this point, is a nuisance to Amoco.

Q. Well, what do you do when you get them from Meridian?

A. When I get them from Meridian or really from anybody, they go straight in the trash can. I can't imagine how we would have an argument coming before the Commission of a problem with a commingled well. I can't foresee what argument would be.

Q. You don't see a correlative-rights concern for you as an offset operator?

A. I do not. You know, I mean, it's a drainage issue, and I don't believe that the commingling affects the drainage, so...

Q. Is it a waste issue if you're an offset operator?

A. No.

Q. Is there any inherent advantage that you see for the operator that seeks the commingling over the operator in the adjoining spacing unit that can't or won't?

A. No, I do not. I certainly wouldn't be throwing away applications if I did.

Q. If you were an interest owner internal to the spacing unit being commingled and that ownership is different, then it would be important to have notice, would it not?

A. Very much so, and we very much support keeping that notice in, albeit it's a difficult notice to do. It costs us a lot of money to go run title and do those things. But we think it's important that our -- And our partners care, and we care as partner. So we recommend keeping that part of the rule.

Q. Working interest owners, royalties, overriding royalties, will get notice if there's a difference in the participating areas or the way that equity is distributed between the two reservoirs within that spacing unit?

A. That is correct, and if they have any problem with that, they can cause it to be -- to come into question, so...

Q. All right. So currently, under the current rule, you put together some kind of presentation with regards to satisfying that at least one zone is uneconomic?

A. Right.

Q. Let's go on to the next item. It says there will be no crossflow between the zones to be commingled.

A. That's an issue that I really haven't been able to provide much information on, because we just don't believe that the crossflow is an issue for many of the reasons that Mr. Daves earlier stated. So that's not something that we provide a great deal of information on.

Q. For you as an engineer, is the issue of having no crossflow an appropriate item to bring to your attention? If you're reviewing an application or preparing one, is the issue of presence or absence of crossflow an issue of relevance to you?

A. As an engineer, no. As a regulatory issue, it still is, so I have to consider before I can make those statements.

But as an engineer in this basin, in these formations, we do not see it as an issue.

Q. Would it be helpful if modifications of administrative procedure were made whereby the Division, without a hearing, can make exceptions or modifications to issues with regards to crossflow?

A. Yes, very much so.

Q. All right. If it's decided that they keep it, then there is certainly usefulness to having this rule modified?

A. Yes.

Q. Let's go on to the next one, which is the fluid-sensitivity issue, number three.

A. Well, our procedure is to typically either pull water samples from our wells that are producing, in the absence -- I have tried to get through a couple of new wells, and in the absence of that we would use information from offsets.

We would internally run a compatibility. We put the two water samples together, or four or six, whatever it is, and run the compatibility test to determine if there were going to be downhole problems from it at pressure and temperature.

Q. Okay. The next item down is the fluid compatibility?

A. Uh-huh.

Q. Now, those are separated. One is a sensitivity --

A. Right.

Q. -- of the reservoir to receiving fluids, and the other is a question of whether the fluids themselves --

A. -- will create scale.

Q. -- will scale or have some contaminants or some kind of reaction among themselves.

A. Right.

Q. So how do you satisfy that part?

A. Well, one is basically dealing with the rock, and one is dealing with the fluids.

And I misspoke earlier. I was talking about the fluids. So I should probably address number three at this point.

We look at that from the standpoint of across the Basin, if our geology is fairly consistent and our fluids have been fairly consistent to deposit the same types of clays or whatever in our sandstones, across the Basin, then we don't feel that there's a problem with that. We've looked at enough core and have a lot of cores out here and have a pretty good feel also from looking at the logs, if we have problems there.

Q. You're recommending no change here, that these continue to be part of the rule?

A. No, we think this is a good part of the rule, and I don't see any reason to change it, and we will continue to provide the information that we have provided all along. So this is not a change in the rule.

Q. The last one deals with pressure, and let's make sure I ask you this clearly.

Regardless of whether the 50-percent number is in the rule or not, you would as an applicant continue to report pressure data, would you not?

A. Yes, we're required to take pressure data, and we are required to present it. And in fact, in the case where we had a well such as what Mr. Weiss was describing earlier, that we're an offset, I would have no problem with seeing the Examiner request us to provide those pressures after we had drilled the well.

I think it's only fair, you know, if we were doing it off offsets and we get our information in and we end up with a surprise, that we really haven't complied with our downhole commingling order by exceeding those pressures. And so therefore I would be fully happy to provide those and take a look at it afterwards.

Q. The problem is not reporting the pressure, the problem is this 50-percent number?

A. That's absolutely correct.

Q. Do you agree with Mr. Daves' proposed solution for a substitution for this rule whereby we utilize the original reservoir pressure of the lowest-pressured reservoir to be commingled?

A. Yes.

Q. Let's touch back on the new drill again. You said it just now. If you're filing an application for a new drill, how do you go through the process of hitting these regulatory pegs with a new drill in the absence of site-specific data as to that wellbore?

A. Well, we would use offset data for the most part. In most parts of the Basin, we're fairly well drilled around, and so at least for the San Juan Basin, I would say that we would have offset information that typically will give you a good read of what you're going to get there. That's how we determine how we're going to drill the well. Economically, we have to have a good idea of what's there to begin with.

Q. All right, let's assume that despite your best effort and your best science you get into a reservoir that busts whatever the pressure differential rule is. If it's Mr. Daves' rule or this rule, you're now with a new wellbore, and you're greater than the rule. What should happen?

A. We should not be allowed to downhole commingle it. In the -- You're talking about when we're exceeding --

Q. Yes.

A. Okay.

Q. You've drilled a new drill as an original downhole completed well?

A. Well, if we're going to, you know, have crossflow that could damage that formation or exceed those pressures, then I would say that we should not be allowed to downhole commingle that well until perhaps later in the life of the well when we can demonstrate the pressures can have come down.

Q. We can go back in the wellbore and set a bridge plug and do something to isolate out the production --

A. That's right.

Q. -- and then produce it in that conventional fashion?

A. That's correct.

Q. Okay. Give us a sense of -- When you submit data to the Division for processing, are we looking at a couple of pieces of paper now or, you know, what does the stack look like?

A. Well, I'm -- Usually about 15 pages, I would say, of information. A cover letter and then about 15 pages total, I would say.

Q. Is there a standardized submittal that all companies use in the same way?

A. Well, a lot of them look like Amoco, a lot of them look like Meridian. I mean, I think we've all kind of come to a generalized form, but I don't know how the Division really feels about it. I'm sure they still have to look around in each of our applications for the particular information that they are wanting.

Q. Summarize for us what particular modifications of this rule will help make more efficient and meaningful the administrative procedures by which commingling cases are being processed.

A. I think the part of the rule -- the pressure rule is a very large item for Amoco. The economic part of the rule is very important to us so that we can get to our wells earlier in their life. And those are probably the two most significant pieces for Amoco.

Q. We've talked about the reference-case --

A. Uh-huh.

Q. -- concept. Describe for us how you envision that process to function.

A. Okay. Are you talking about how reference cases would be established or --

Q. Yes.

A. Okay.

Q. How do you build one?

A. Well, I can see one probably coming for Amoco in a couple of the formations that we haven't talked about here today, and I can see us finding the need very soon in the Basin to have reference cases built for those formations, based on our historical information.

And so I would see an operator, if it were of interest to them, or perhaps the Division, if it were something that they were seeing a lot of collective types of downhole commingling applications, perhaps they might choose one to be used as a reference case so that they wouldn't have to wade through all that information every --

Q. Now, the reference case could be specific as to any component of the rule, could it not?

A. Exactly, and I would say that when we had a reference case, perhaps I would provide all the base information, and I might only use part of that reference case.

For instance, I might use -- If we were to relax the pressure rule in the San Juan Basin, I might only use that on my form as support. But perhaps if I were in an area where my water compatibilities were different, I would not be using that if that were a part of it.

So I think you could use selected parts of a reference case and not just a blanket, entire case.

And I still see a great deal of information that we're going to be providing on the form at any given time along with the reference case. I don't see us just saying, here's my well and here's the number, you know, and that does it. I see us having to provide all of the base information, as well as some of those things being qualified by the reference case.

Q. Do you perceive the reference case procedure to be flexible enough where the agency and the applicant or operator can develop a reference database, perhaps on a formation or an area and a formation, it could have several components to it in terms of how large an area is referenced by that order?

A. Yes, and I think similar to some of the things that we see in allowables where we grow the pool, you could probably grow the reference case, I would think.

MR. KELLAHIN: That concludes my examination of Ms. Staley.

We would move the introduction of Amoco's exhibit.

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

Questions of Ms. Staley?

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, the Chacra wells. Earlier this morning we heard about Pictured Cliffs, Mesaverde, the Dakota. What's the area location of the Chacra wells?

A. We're up to the northwest slightly, so in that Basin pool it overlies -- A lot of our work is in the northwest one-third of the Basin.

Q. But they basically -- They're within the pool limits, huh?

A. Within the pool limits, that's correct.

Q. Okay. With that in mind, tell me about reference cases again. I don't understand the need for one.

A. What I would see is a need for establishing certain areas where you can use data that applies to that area. Our --

Q. Isn't that established now? Don't we have that? My sense was this morning that we know about the Pictured Cliff, the Mesaverde and the Dakota, and I guess I understand now that the Chacra is pretty much --

A. Well, I'd have to give you specific information, I think, from each formation always.

In a reference case we would establish in that area that a lot of the base information on those two pools that applied for downhole commingling would be the same, or very similar, and therefore we could -- rather than going out and extracting that information, we could use a reference case -- It would be something that basically the Examiners would not have to look into further.

Q. Well, would a reference case involve pressure, or is it primarily, maybe, for the fluid-compatibility problem or --

A. I think it could be either or both. Any reference case could establish commingling parameters for any variety of things that go on, on this form, or apply to the rules.

COMMISSIONER WEISS: That was my only question. Thank you.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. But the applicant would be able to pick and choose which characteristics of the reference case they would like to invoke for their particular application?

A. That's the way I would envision it. I wouldn't say pick and choose, but if they applied, if they were applicable -- The entire reference case might not apply in your area to your particular well. So it wouldn't be like expanding a reference case, but you would be able to say that the well I'm going to downhole commingle in these two formations has this particular characteristic that's been proven in this case to be similar all over, and therefore I'm going to refer you to that case for that particular item.

Q. Amoco will only have one well -- one rig drilling this season. How is that compared to last year?

A. We had two rigs last year, and that is our plan at this time, is to only have one rig drilling, and we should keep that continuously busy.

Q. Okay. If these rules were approved, would that necessarily change Amoco's decision to have only one drilling rig out there?

A. At this point it would change our choices. And as our choices change of wells that we would drill -- Our budget process is to look across our company and see where our opportunities are.

The San Juan Basin opportunities don't stack up as well against other investment opportunities, because we're not getting as much gas for the amount of money that we're investing. Therefore, if we are able to demonstrate to our management that we have opportunities that are now greater for the money invested, then our opportunities move up in the list of projects that Amoco wants to do as a company. And so moneys will probably be transferred back into our portfolio as they compete better with other business units in our company.

So I -- While I can't say, yes, we would run out and put another rig on, when we look at our opportunities and tell our management whenever this rule would occur that, look, we have these opportunities and we're now able to do this up front and that reduces our investment costs and increases our production, then basically they compete better in the company, with other companies.

COMMISSIONER BAILEY: I have no other questions.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Ms. Staley, let's get back to reference cases, because I think -- I think the concept is good; I would just like to see it further defined.

Your idea of a reference case would be one that would encompass a geographical area. You would reference certain townships in which applications would not be necessary to commingle these zones?

A. Oh, no, that's not the way I would envision it. I would envision that an application would still be necessary, that the base information for that well would still have to be provided.

Q. What about wells that -- I mean, a lot of this would be -- We can't drill to that formation unless we can commingle it, therefore we want preapproval, basically, for commingling. Would that apply to a reference-cased area or an area --

A. Yes, yes.

Q. So then you wouldn't need individual well applications; you could just refer to that one case, couldn't you?

A. Well, I would refer to the case, but I would still have to file, I believe, the base information with you for that well, for your records and for --

Q. After the well was drilled or before?

A. We would file the information for the application prior to, and then as I envision it, like I said, later if that data was different, then we would need to update you with that information. You know, if we hit a pressure pocket or if we get, you know, fluids that were not incompatible.

Q. All right.

A. That were not compatible, pardon me.

Q. Yeah. So I guess what we're trying to do is, say, to ease the burden on industry, we're trying to eliminate a lot of the -- maybe the paperwork.

What I was hearing earlier was that they would like to see some kind of a reference, or you all would, for the San Juan Basin on at least PC, Mesaverde and Dakota being commingled within defined pool limits, maybe by this order. I'm not sure. But I mean I thought that -- So then if you were going to commingle, you wouldn't have to go through that application process again; it would be almost commingle -- You would have to be able to commingle by rule? Is that what you're getting at?

MR. KELLAHIN: That was not our intent, Mr. Chairman. Let me see if I can clarify --

CHAIRMAN LEMAY: Yeah, okay.

MR. KELLAHIN: -- what we're trying to do.

Whatever form is utilized --

CHAIRMAN LEMAY: Yeah.

MR. KELLAHIN: -- let's assume for argument this is the form --

CHAIRMAN LEMAY: Okay.

MR. KELLAHIN: -- when you file your C-104 for your application for permit to drill --

CHAIRMAN LEMAY: Yeah.

MR. KELLAHIN: -- you would concurrently file for that new well this commingling application. You've got all the data in here that's available to you.

When you get to these subdivisions, particularly if pressure is still in the rule, the 50 percent -- Let's say that stays. We would then be able to either submit individual information or we can use Mr. Daves' reference case whereby Mr. Catanach, when he looks at this, says, I know pressure is not a problem for you with this PC-Mesaverde commingling. You don't have to worry about that pressure limit for me. So long as you stay within whatever that threshold pressure is, you're free to go.

She drills her well, she comes back under his order that's approved this, and says, I've exceeded the pressure. The process would be, then, she's going to have to postpone commingling on that new-drill until she's in compliance with whatever pressure criteria you give.

So the example is that Mr. Daves is asking you to consider two things: one, that his presentation for the Pictured Cliffs, the Mesaverde and the Dakota could be a reference case to delete the 50-percent requirement out of this rule. And if you agree with him, then the next time they file one of these, they're going to use this case number as that reference point.

In addition, the second point that he's asking you to consider is, this could be a reference case on item one, which is the economic criteria. You may be fully satisfied that every time you see another commingle application for Mesaverde, that's inherently going to be marginal. Why worry about putting together the graphs and the information when we all are going to concede that it's marginal, if that's your answer? And so when he gets down here, he fills that in. But he would always get this application.

CHAIRMAN LEMAY: An application for each well --

MR. KELLAHIN: Yes.

CHAIRMAN LEMAY: -- that's going to be drilled?

MR. KELLAHIN: Absolutely.

CHAIRMAN LEMAY: Some of the information like fluid compatibility wouldn't be available after you drilled the well.

MR. KELLAHIN: Well, it isn't now.

CHAIRMAN LEMAY: Right.

MR. KELLAHIN: Some of that stuff you're doing now and getting information later. It's done by analogy.

MR. KELLAHIN: So I guess every commingling application or every authority to drill under a commingled order or whatever you want to call it, okay, you can commingle, is always conditioned upon subsequent testing of the fluids, that they're compatible.

MR. KELLAHIN: Yeah, you do that now, and we're not asking you to change that.

CHAIRMAN LEMAY: Okay.

MR. KELLAHIN: That's no change.

CHAIRMAN LEMAY: I understand better now --

MR. KELLAHIN: Yeah, you're doing that.

CHAIRMAN LEMAY: -- the reference case, yeah.

MR. KELLAHIN: When David signs those draft orders that you sign, they have some conditions on them.

CHAIRMAN LEMAY: Uh-huh.

MR. KELLAHIN: They have some conditions. And there could be standard conditions on there, that on a new drill if you exceed whatever he says is the pressure of the lowest-pressure container, and when you report that and -- or you self- -- police yourself, then you can't commingle. So I think that's how you handle it.

CHAIRMAN LEMAY: Okay, that clarifies some of my fuzziness.

MR. KELLAHIN: No, this is not a blank check where we're going to go out and punch holes all over the San Juan Basin. There is regulatory review and approval that goes on in this process.

CHAIRMAN LEMAY: That's all I have.

Any additional questions?

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Yeah, on the question of the abnormal pressure or overpressure or something, has that ever happened? Does that ever occur?

A. We have seen -- The only case I can think of is in the lower Dakota where we have gotten surprised by some wells in a very noncontinuous Dakota zone. It was not a downhole commingling issue, but we have gotten surprised in the Basin twice.

Q. Isolated --

A. Very isolated, they're isolated little, very small bumps. And we found a few -- yeah, I think two of them we've found. But that's the only ones I'm aware of that we've gotten surprised off the pressure pockets.

Q. So maybe we could discount pressure as a part of the requirements for commingling.

And then also I think that you said that you have not seen any fluid problem. I mean, the wells haven't scaled up when you've commingled or something of that nature; is that right?

A. We haven't seen them at all, and we look at that data, we look at the water test and we run it, and we have not seen it.

It's not something -- I think, as Scott said earlier, as a company it's something we want to watch out for and we don't want to do.

Q. So it appears to me that it's coming down we only need one reference case for the San Juan Basin, or at least within the pool limits?

MR. KELLAHIN: That's what we're asking you.

THE WITNESS: Right --

MR. KELLAHIN: We've come to that --

THE WITNESS: -- we think it's at that point.

MR. KELLAHIN: -- conclusion, it's your decision or the Division's decision how to handle that reference issue.

But that was our presentation this morning.

COMMISSIONER WEISS: Okay, that was my other question. Thank you.

CHAIRMAN LEMAY: Anyone else?

You may be excused. Thank you very much.

MR. KELLAHIN: We want to shift gears and areas, Mr. Chairman. I'm going to call Mark McClelland. Mr. McClelland is an engineer with Conoco.

We want to move to southeastern New Mexico and deal with a part of the rule that is a concern for the oil operators.

In addition to having the industry committee agree as engineers with regards to the technical changes, Mr. McClelland has a specific example of what I described earlier where the difficulties with the oil allowables based upon depth, which is the first page of Exhibit A to the order we're talking about, in which by increments of a thousand feet the combined total daily oil allowable is increased by increments of ten barrels.

And that really is the focus of Mr. McClelland's presentation.

MARK McCLELLAND,

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

A. Yes, my name is Mark McClelland. I'm a reservoir engineer with Conoco. I live in Midland, Texas, and I work the southeast New Mexico area, predominantly Lea County.

Q. Mr. McClelland, on prior occasions have you testified before the Division and qualified as an expert petroleum engineer?

A. Yes, I have.

Q. As part of your duties as a petroleum engineer for your company, are you involved in looking at downhole commingling opportunities with regards to some of the reservoirs in southeastern New Mexico?

A. Yes, I am.

Q. And were you involved on behalf of your company with the industry committee that has been examining modifications and amendments to -- proposed to the Commission for consideration in changing Rule 303?

A. Yes, I have been.

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

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. (By Mr. Kellahin) Let's take a moment, Mr. McClelland, and set the stage for your discussion. If you'll turn to the geologic locator for us --

A. Okay.

Q. -- help us find those pools that you want to discuss today, and let's begin that discussion.

A. My discussion -- Second page in your handout is a geologic correlation chart. My discussion concerns the Central Basin Platform.

In this area I've seen quite a bit of activity in the section known as the Yeso or Blinebry, Tubb, Drinkard and also Paddock. And this is the example I brought today, this will be the area that I address.

Q. Okay. When we look at these examples, where are we geographically in southeastern New Mexico?

A. We are in the extreme southeastern corner of New Mexico, in Hobbs, Lea County. We're probably in the area south of Hobbs down to Jal, New Mexico.

Q. On page 3 you have summarized your recommendations, particularly with regards to the maximum daily oil rate that you're allowed to produce under commingling. Help us understand that issue, if you go ahead and summarize for us what the problem is, and let's talk about a potential solution.

A. The big problem that I've run up against in looking at Conoco's wells in this area is the producing cap that is allowed for downhole commingled wells. It's restrictive, it's low, and it curtails production and recovery.

Q. Are any of those levels within the current 303 table equivalent to what you could produce as an operator in the absence of commingling of that particular reservoir?

A. No, they're much less. For example, Exhibit A, that we -- that was passed out this morning, under downhole commingling you will see a table of oil production rates based on depth, for the interval from 6000 to 7000 feet. That is 40 barrels a day.

An equivalent rate for a Justis-Blinebry well would be 107 barrels of oil per day for that depth. That depth bracket allowable would be 107.

Q. You could have 107 in the Blinebry if it was not commingled?

A. That's correct.

Q. And under commingling, then, you'd get --

A. -- 40.

Q. -- 40. And that's to be shared with any other zone being commingled, right?

A. That's correct.

Q. Okay. All right, so that's the Blinebry, and this is 40-acre oil depth bracket allowable, 107 barrels a day?

A. That's correct.

Q. What would you likely commingle the Blinebry with?

A. Most likely the Tubb and Drinkard.

Q. And where would you find that depth?

A. Tubb and Drinkard, depending on where you're at in Lea County, it still falls within that same depth bracket, normally the 6000 to 7000 feet.

Q. So if you keep the wells separated, each pool, then, would have 107 barrels?

A. That's correct.

Q. As a dual?

A. That is correct.

Q. All right. So you'd have a total of 214 out of that wellbore?

A. That's right.

Q. On a dual-production configuration?

A. If your well had that capacity to make that rate.

Q. All right. And if you commingle them, you're at

40?

A. Forty, right.

Q. You've lived with that rule for a while, haven't you, Mr. McClelland?

A. Yes.

Q. You've attempted to operate under the constraints of that rule?

A. Yes.

Q. Let's show the Commission an example that you've brought of what you have to do in order to stay consistent with that oil cap. Let's look at the State A 2 Number 4 well. You've got a well history.

A. Yes.

Q. Let's turn to the next page and have you summarize for us the well history and then we'll look at the graph.

A. Okay. We're on this exhibit. It says "State A-2 Number 4 Well History".

Part of my responsibilities as a reservoir engineer is to ensure that we are recovering -- maximizing recovery of oil and gas from our leases.

We have an 80-acre state lease here outside of Jal, New Mexico, that I studied back in 1990, and realized that we had additional recovery to be made in this area. This area was developed in the early 1960s. It's an area that has multiple formations. The original two wells -- It was developed on 40 acres.

The original two wells had three strings of tubing cemented in an open hole, often called a tubingless triple completion. And while that was all well and good for initial production, it sort of made workover operations a mechanical nightmare out here.

In effect, we could not work over our wells to recover additional reserves that we felt were in the ground. Thus we justified the drilling of the State A-2 Number 4 in 1991. This well was justified and planned as a dual completion. We were targeting the Abo and the Tubb-Drinkard formations for production initially.

To summarize this history, basically the Abo was noncommercial as a dual. We abandoned the Abo, we completed in the Tubb-Drinkard -- that's the Justis-Tubb-Drinkard Pool -- in October, 1991, produced that for about a year, set a plug, abandoned that production, came uphole to the Blinebry, produced the Blinebry for approximately six months, downhole commingled Blinebry and Tubb-Drinkard together in April, 1993, through an administrative order.

Two years later we went back and tried again to dual with the Abo. We were not successful in doing so.

In August, 1995, we received a Division order that allowed us to put the Abo in a downhole commingle state with the Blinebry and Tubb-Drinkard.

Q. In this particular example, you are faced with choices of commingling Blinebry, Drinkard and Abo, was it?

A. That's correct.

Q. Of those zones, which is the best oil producer?

A. The Blinebry.

Q. So the Blinebry is the shallowest zone, it's your best oil producer. How do you justify getting the lower formations produced?

A. It's basically incremental economics. When you drill a well, you realize the next zone down is probably only a couple hundred feet deeper, but yet it may give you 10 or 15 barrels a day.

But in order to justify that well, you still need to get a payout. So you need to bring those streams, those lower marginal streams, on line as quickly as possible until you get to your strongest zone. You can't afford to complete that initial zone if it's marginal and produce that thing for ten years and expect to pay out your wellbore.

Q. In response to the industry's request that these oil maximum rates be increased, the Division has proposed to the Commission that each of these rates be tripled.

So if we look at your level between 6000 and 7000 feet, if you triple that to 120 barrels a day, would that provide an opportunity for Conoco and others to drill a new drill where you could package together all these zones to be commingled and have enough of an allowable to help get you the economics to justify the well?

A. Most definitely.

Q. Let's look to see what you did in the production plot, of how you had to cope with the existing rule for the State A-2 Number 4. If you'll look on the display you've brought, you've got a horizontal black line across the display, and you've captioned that "40 barrels".

A. That's correct.

Q. That's your cap?

A. That's our cap, that's our ceiling.

Q. All right. Starting with the first black arrow, describe for us what you had to do in order to keep your production below the commingled oil cap.

A. Again, this production plot is just showing the history of the previous exhibit.

On the first arrow we completed in the Justis-Tubb-Drinkard zone. That was in October, 1991. Our production fell fairly rapidly, as you would expect in a replacement type well. You get some flush production and then it stabilizes off at some lower rate, in this case about 12, 15 barrels a day.

We produced the well for about six months to make sure we had some stabilized production that we could come to an administrative application with, to show that we did have some stabilized production, we could allocate production in a downhole commingled state.

The second arrow, in 1992, is when we isolated that Tubb-Drinkard production, we set a plug, shut it off. We opened up the Blinebry zone and brought on approximately a 35-barrel-a-day oil well.

At that point I came to our regulatory personnel, Mr. Hoover, and said I would like to downhole commingle the Blinebry and Tubb-Drinkard together. He informed me that that added production would exceed the 40-barrel-a-day cap; we could not do so. We would have to wait till that production dropped to a point where we could add it back into the Tubb-Drinkard.

So about six months later, that well had dropped off to 25 barrels a day, where we felt we could add in the Tubb-Drinkard and not exceed that 40-barrel-a-day cap.

The third arrow is when we did this work. That's in 1993. And you can see the well came right up to the cap, 40 barrels a day, stayed there for about three months, and it has declined on out since.

So in effect, this cap, this artificially low cap, has driven the timing of accessing these marginal reserves.

Q. Do you have another example where you reach the same conclusion?

A. Yes, I have one more example in this package.

Q. Let's look at the last page, then, and have you explain that example.

A. We have one more well out here. As I said, this is an 80-acre lease. The next well we drilled was the State A-2 Number 5. It's the south offset to the Number 4.

Being the eternal optimist, I thought we'd do better in the Number 5, so we decided to try it again. This time we did not go after the Abo. We felt like it was marginally -- it was marginal, it was uneconomic for us to drill down through the Abo.

We stopped at the base of the Drinkard, made a completion in the Justis-Tubb-Drinkard in January, 1994. Again, if you see this exhibit, State A-2 Number 5, you can see our completion in 1995. It acted very similar to the previous well, the Number 4: 50 barrels a day initially, dropping off to 20 to 22 barrels a day rather rapidly.

We immediately shut this well in. The last test was 21 barrels of oil per day and 363 MCF per day of gas, which is still a good rate but it's not sufficient to get the economics back on this well that we need to continue this type of work.

So we set our plug, isolating Tubb-Drinkard, came uphole, opened the Justis-Blinebry and we got a nice Justis-Blinebry well, initially over 100 barrels a day. Currently it has 70 barrels of oil per day.

We made a projection on this Blinebry zone, while still fairly early in the well's life. It looks like this well will not decline out to a level where we can downhole commingle for another two years. That is, we could not downhole commingle Tubb-Drinkard back with the Blinebry until the current production drops from 70 barrels a day down to 18 barrels a day, because, again, of this 40-barrel-a-day cap.

Again, this cap is driving the timing of accessing additional reserves in the wellbore, and this drives the economics and the payout of the wellbore.

Q. Is this an efficient way, in your opinion, to manage this resource?

A. No, it is not.

Q. If the Commission adopts the Division proposal to triple the current table, would that in any way violate correlative rights or be a concern that waste will occur?

A. No, it will not. In effect, it may actually encourage some additional infill-type drilling activity such this, or replacement-type activity.

Q. Would increasing the oil rate for the commingled well give that wellbore somehow an unfair competitive advantage over any offset well for which commingling has not been undertaken?

A. No, it will not. As we've seen, if we even triple the downhole commingling cap, it is still fairly close to what the individual zone production depth allowable bracket is.

Q. Do you see any opportunity for abuse or manipulation of the process by any applicant by increasing the oil rate?

A. No, I think the process is designed to encourage additional recovery in opening marginal zones and adding them to the well production stream.

Q. The Division has under consideration some pending Examiner cases where the applicant -- I believe Enron was one of them -- sought to have oil commingled using the maximum daily oil rate, based upon the depth bracket oil allowable assigned for the shallowest pool. Are you familiar with that concept?

A. Yes, I am.

Q. If you were to make a recommendation for the Commission with regards to whether this table is tripled or whether they adopt the maximum oil allowable of the shallow pool, do you have a recommendation or a suggestion?

A. I would recommend the tripling, but I realize that there's not a whole lot of difference between tripling and the depth allowable bracket.

Q. In either instance, whichever one they adopt, do you see any opportunity for impairment of correlative rights or causing reservoir waste?

A. No, I do not.

Q. You participated on behalf of your company with the industry committee with regards to the other issues, did you not?

A. Yes, I did.

Q. And without asking you specifically, do you concur with the conclusions and opinions that Mr. Daves and Ms. Staley expressed to the Commission?

A. Yes, I do.

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

We move the introduction of Conoco's exhibits.

CHAIRMAN LEMAY: Without objection, Conoco's exhibits will be admitted into the record.

Questions of Mr. McClelland?

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yes, sir, are your examples here, are they infill wells? Did I hear you say that?

A. They're replacement wells.

Q. Replacement wells. So the reservoir and the reservoir size, reserves, are pretty well established?

A. Yes.

Q. For all the zones?

A. Yes.

Q. Are the fields unitized? Are they --

A. No. There are pools --

Q. They're not secondary --

A. -- established.

Q. Yeah, the pools are established, but they're not secondary units, waterflood units?

A. That's correct. Now, just south of this lease there is an established waterflood unit, the Arco South Justis unit. But this lease was not included in that.

Q. Well, does your commingling request here -- What does that do to your reservoir-engineering efforts? By that I mean determining recovery efficiency and your estimates of original oil in place, and do these things -- How does that affect that type thing?

A. It doesn't really introduce any more uncertainty than is already out there. We can allocate production fairly accurately.

Even on a predrill I think we can do a very good job of allocating production.

COMMISSIONER WEISS: Fine, my only question.

Thank you.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. I'm trying to understand the reason for the cap to begin with.

A. Good, so are we.

Q. Part of the table.

But did I understand you correctly that you would prefer to see tripling of these caps rather than basing it on the allowables for the pool? I don't understand why you would say that.

A. Well, again, let me run through the examples from 6000 to 7000 feet.

The depth allowable -- The state has depth allowables for their oil wells. At 6000 to 7000 feet it's 107 barrels of oil per day.

The shallower allowable, I believe, is 80 barrels a day for the next depth bracket down.

The next depth bracket up is 142.

So based on the depth of your well you have a certain allowable production that you can make.

What we're proposing -- Currently the cap is 40. We're proposing a tripling of the cap to 120.

Q. Which would essentially set it higher than pool --

A. Yes, slightly higher than the depth allowable for that pool. It would be 120 versus 107.

Q. Okay. Do you see an impact on pool allowables if this cap is set at this higher --

A. No, not at all. Predominantly, you will find very few restricted wells in New Mexico. There are very few allowable wells in New Mexico. Your average production is probably 10 to 15 barrels a day, if that good.

COMMISSIONER BAILEY: Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. You didn't address the water issue. I think a lot of our table here has to do with both oil and water. It has limits set to the water.

As I understood the other proposal, since water wasn't addressed, I assume if you're picking a top allowable for the shallowest pool zone, you would still carry -- your recommendation would still carry that no more water would be produced than oil?

I mean, you're limiting fluids in this table. You're not limiting fluids, total fluids, when you're talking about top allowables for zones?

A. That's correct. I believe currently the way the rules are stated, you're allowed to produce twice as much water as oil. I think water is limited to two times the oil of the well.

We are not recommending any change to that; we are just asking for increase in the oil cap, which would, in effect, allow the water production also -- twice the oil, twice the oil cap, if I --

Q. So you're really talking about fluids three times the allowable? Basically, you could go as high as three times the allowable of the shallowest zone for total fluids produced. Instead of 107, you can go 321 barrels a day?

A. That's right, that's correct.

MR. KELLAHIN: Only 107 can be oil; the other could be water.

And we would -- Whatever schedule you adopt, we need relief on the water volume. And so the way this was proposed by the Division is that the oil table would triple, that correspondingly, the way the rule was written would double the water rate. And that's one solution.

If you adopt what Mr. Cate is about to recommend, then it's a little different oil rate, but you could still double the water based upon his oil rate.

There needs to be -- and I think he could perhaps address it -- there needs to be relief for the water limit. I think everybody recognizes that as too low, and we have found no one that finds that's a serious problem if it's increased.

THE WITNESS: Have I confused you?

CHAIRMAN LEMAY: I haven't heard water mentioned. That's why I wanted to bring it up.

THE WITNESS: Okay.

MR. KELLAHIN: Because it wasn't an issue for us, we concurred in what the Division had proposed in increasing the water, and so we've not addressed it. If that's an oversight, we'll certainly have somebody fill it in.

CHAIRMAN LEMAY: I just need that addressed and where it becomes a fact.

Anything else? Commissioner Weiss?

COMMISSIONER WEISS: One other question.

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Again, your thinking is, this applies to infill development rules, not new discoveries or new pools?

A. That's correct.

COMMISSIONER WEISS: That was my only question. Thank you.

FURTHER EXAMINATION

BY CHAIRMAN LEMAY:

Q. Reference cases, do you believe in these reference cases that we're talking about?

A. Yes, I do. In effect, we're actually using that right now. We get everybody else's applications also, and if they're close to our wells, we -- if we don't have the data we use their well as analogy.

Q. You've got lots of information like they do in the San Juan Basin?

A. That's right.

CHAIRMAN LEMAY: That's all I have.

Any other questions?

Yes, David?

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. McClelland, I believe one of the Division's recommendations was to double or triple the current rate tables in the rule book.

Do you have an opinion as to whether doubling will be or not be sufficient for what you guys need?

A. Doubling would certainly help us out. It's a significant step above where we're at currently. So yes, that would definitely help us out.

What I would be concerned about are in some wells where you do have some flush production where you might in fact still exceed that doubling, you would have to curtail the well for a few months. That's where I feel like tripling would give us a little more incentive to bring on that flush production initially, realizing we're going to be facing very steep decline in these wells. And really, the more production you can get the earlier in the life of the well, the better your economics are.

CHAIRMAN LEMAY: Any other questions of Mr. McClelland?

COMMISSIONER WEISS: One more.

CHAIRMAN LEMAY: Commissioner Weiss?

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. In regard to allowables, should we have allowables on wells of this nature?

A. It's a very good question.

If I can back up one year, I posed the very same question to this man right here. When he came up for an industry open hearing -- meeting -- I said, Why do we have allowables?

Q. I mean, a well is essentially depleted in a year or two.

Maybe you ought to bring that up again next month, huh?

A. I think allowables had their time and place.

But in the environment that we're in currently -- Outside of new discoveries, in the environment we're in currently, I don't see where they really apply to most of our wells we have today.

COMMISSIONER WEISS: Thank you.

FURTHER EXAMINATION

BY CHAIRMAN LEMAY:

Q. Just -- In terms of allowables, because we have had this discussion and since we're addressing them here, I think they're really there as a refutable MER number. I mean, they came somewhere. At one time they served a different purpose.

But unless we have MER hearings on each field, it's very difficult to assign a number. So I think you're familiar -- We've increased allowables, certainly --

A. Yes.

Q. -- to hearing where there's evidence to show that those things aren't cast in stone.

A. That's right.

Q. I guess you have to start with a number somewhere before you can adjust that number. I'm not defending the number, the allowable, but I'm saying it seems to be there, and people can use it to go up from in the event they have indications that it needs to go up.

A. And I respect that. With the Commission we have come up several times on pool-rule changes and saw some of these different scenarios where we feel like it made engineering judgment and good sense to do so. And we've been very well received, and we've done so also.

Q. I guess I have another question, as long as you're there. We started on some of this.

You've heard the pressure-differential arguments for the San Juan Basin. Would that apply here too? You wouldn't want to exceed the initial bottom -- I mean, I realize your pressures are so low, I guess, that --

A. They are.

Q. -- you probably wouldn't exceed reservoir pressure. Would that be a limitation that you see as a factor?

A. It's a little different here, I think, in the southeast. I think our next witness will address this probably better than I can.

Q. Okay.

A. My area is predominantly solution gas drive reservoirs that are fairly well depleted, and we don't really run into that big pressure differential that much.

Now, I will say, most of our reservoirs are fairly tight. We have to sand-frac these reservoirs to make them produce. And predominantly when we pump these wells, they are pumped off on time clocks.

So even if we do have some fairly large pressure differentials, when we're producing the well it's at an almost zero-pressure condition anyways.

CHAIRMAN LEMAY: Okay, anything else?

Thank you very much. Appreciate your testimony.

MR. KELLAHIN: May I respond to Commissioner Weiss? The industry committee was concerned about the allowable issue, and one choice was to piggyback the commingled well, using the depth bracket allowable. Although it's arbitrary, at least it is consistently arbitrary.

Our concern about not having an allowable was that we all recognized there was an opportunity for abuse, whereby in a pool that had good-capacity oil production, an operator could file for commingling and thereby avoid any allowable curtailment on his oil production and have an allowable in a competitive field that was in excess of what his competition was doing.

And so rather than create a windfall or an opportunity for abuse, the discussion centered on taking the shallowest pool's allowable and pegging that as the commingled cap. And so that's where that discussion took place.

COMMISSIONER WEISS: Does that situation apply to new fields, not to old fields? I mean, old fields that are well defined and established, I see there's less concern, I would think, for competitive development.

MR. KELLAHIN: Yes, sir, in looking at a

statewide rule, we were -- the dilemma was to try to separate out new from old, and we just couldn't figure it out.

But you're quite right, in an older field it's not important. In a new field it becomes an issue for all of us.

That concludes our technical presentation.

There is another technical witness.

(Off the record)

CHAIRMAN LEMAY: Let's take ten minutes and come back, just as a break.

(Thereupon, a recess was taken at 2:20 p.m.)

(The following proceedings had at 2:37 p.m.)

CHAIRMAN LEMAY: Okay, we shall continue.

Ms. Trujillo?

MS. TRUJILLO: Thank you, Mr. Chairman. Again, my name is Tanya Trujillo, and I'm here on behalf of Enron Oil and Gas Company. We have one witness today, and when I find my outline -- there it is -- we'll be ready.

RANDALL S. CATE,

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

DIRECT EXAMINATION

BY MS. TRUJILLO:

Q. Could you state your name, please?

A. Yes, my name is Randall Cate.

Q. And by whom are you employed?

A. I'm employed by Enron Oil and Gas Company in Midland, Texas.

Q. And what is your current position with Enron?

A. I'm a project reservoir engineer.

Q. Have you previously testified before the Oil Conservation Commission?

A. Not the Commission. I have testified in front of the Division many times.

Q. Well, let's go through your educational background.

A. All right. I graduated with a bachelor of science degree in mechanical engineering from the University of Texas at Austin in 1979.

I worked for Gulf Oil corporation in Odessa for two years, approximately. Then I joined Texas Oil and Gas, or TXO, primarily as a reservoir engineer -- I also had some production and drilling experience there -- for ten years.

1990, I joined Enron Oil and Gas as project reservoir engineer, and that is still my current assignment. And for Enron and most -- TXO was primarily southeast New Mexico.

Q. And you stated you have testified many times before the Division, correct?

A. Yes, I have.

Q. And have those cases involved applications for downhole commingling?

A. Yes, two of them have.

Q. And has Enron received approval for downhole commingling projects?

A. Yes, we have received some administrative approvals, and also we received one approval so far on a docket order, a hearing order, and then we've got one pending at this time.

Q. Are you familiar with the provisions of OCD Rule 303 and the proposed amendments to the rule?

A. Yes, I am.

Q. Have you discussed these proposed amendments with other operators in southeast New Mexico?

A. Yes, I have.

Q. And are you prepared to provide Enron's comments to the Commission regarding the proposed changes?

A. Yes, I'm here to support the efforts of the committee and the Commission to amend the downhole commingling rules. I will share Enron's experience, downhole commingling, and also in a new area that has yet to be testified to in southeastern New Mexico, which is primarily the Delaware Basin, and I will also review downhole commingling activity of southeastern New Mexico that the industry has encountered, say, in the last five years.

MS. TRUJILLO: Mr. Chairman, I tender Mr. Cate as an expert reservoir engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

MS. TRUJILLO: Thank you.

Q. (By Ms. Trujillo) Now, you had said you were going to summarize the activity, downhole commingling activity, in southeastern New Mexico with regard to Enron's projects and other operators' projects. Do you want to do that at this point or --

A. Yes.

Q. -- later? Okay.

A. Yes, I'd want to go right into Exhibit Number 1, which is the producing zone map that's shown here. And just quickly, the outlined or colored areas -- you've got magenta and green and kind of a red -- they show areas of industry activity from Commission records on administrative approvals.

And also, then, I've had discussions with Bass, Santa Fe, Yates, on areas that -- assuming the rules are relaxed, where would they anticipate future activity?

And I wanted to go ahead and comment first that, as you can tell, this map is primarily just Lea and Eddy County, approximately, you know, two-thirds. And then if you see this kind of semicircle through here, this dashed semicircle line, well, this is where the Delaware Basin -- south of that is this Delaware Basin area which I'll primarily be talking about.

What you saw Mr. McClelland testify to, their commingling efforts are up on this Blinebry area, Tubb-Drinkard, and that's up on this platform area right here, up on the Central Basin Platform. Many, many applications and approvals have been filed in this area that he's talking about.

Also, Yates indicated that they would see some activity, some possibilities in their Dagger Draw area, bringing in some Wolfcamp gas. What's hampered them there is the high water. But they may be interested in coming in with a reference case there.

Generally, throughout this area here, we have seen a lot of Morrow and Atoka. Again, you can see Morrow-Atoka-Strawn is this magenta color, not so much over into the southeastern portion here, but more in this central area. Primarily gas zones, and they're deep and they're primarily gas zones. That's what the industry has been doing for downhole commingling there.

I don't plan on talking much about that. I don't see that the proposed changes -- in any discussion with industry, we just don't see that there will be much difference as it applies to the Strawn-Atoka-Morrow.

However, we do see that it could be a significant change and an encouragement to a lot of activity for what is outlined in the red, which would be the Delaware, Bone Spring and Wolfcamp zones. This area here, to the east over here in red, is an area that Yates talked about. Enron's activity is in this kind of mid-southern range here. Santa Fe indicated an interest in future activity here. And we've seen some activity also in those pays here and again here.

So I think the great majority of the future activity will be from this colored -- or circled in red, and that is Delaware, Bone Spring and Wolfcamp.

Q. And where on this exhibit is Enron's most recent project again?

A. Okay, we -- Our experience, one year ago we came to a hearing and received approval to downhole commingle the Wolfcamp and Bone Spring in our James Ranch area, which is approximately right here, okay? It's in this center red circle.

It was very successful. We made a good well on that and have now subsequently come in to expand that to about a three- to four-square-mile, or section, area. So we've got an areawide proposal out here that's pending.

It also would now include commingling of the Delaware zone in addition to what's already been approved in the James Ranch 71, which was the Wolfcamp and Bone Spring zone.

Q. And that was -- You came before the Division in November; is that correct?

A. For this areawide one that is pending, that's correct.

Q. Okay. Now, did you mention that Texaco is also active in the area or interested in this?

A. Yes, the same day that we were here and presented our James Ranch areawide case, Texaco presented one right on this Lea County-Eddy County line, right down here, for the Delaware and the Bone Spring also. And I understand that it is currently pending also, pending this policy decision here. And they did come in and ask for the same allowable or oil limits which we did, which are the top allowable based on the depth bracket for the shallowest zone commingled.

Q. Was the Texaco application also an areawide or blanket application?

A. Yes, I believe it encompassed 320 acres, so it was not just a single well.

Q. Now, Mr. Cate, regarding Enron's applications or activities here, what is the purpose of those activities?

A. The purpose of our commingling activities in support of the relaxing of these rules is -- One would be efficiency.

Number two, it would be increased recovery.

Number three, operationally it is the most prudent and basically necessary that we do get to commingle.

And number four would be economic waste, either by drilling two wells for the same reserves, or a company may not -- or may be forced not to drill to the deeper marginal zones because of the postponement of getting a return on that investment. So that would be an economic waste and a forced postponement of productions.

Q. So it would be too expensive for Enron to drill two different wells for two different formations?

A. Yes. There are cases that it can be done, but in general it would cost Enron an extra $600,000 to $700,000 to drill another well that we could go ahead and have one well get all the reserves.

Q. So Enron is actually seeking downhole commingling authority for new wells, as well as existing wells?

A. Yes, and not just new wells, but original reservoir pressures, which is something you haven't seen yet. Most of the testimony has been in depleted reservoirs or at least mid-life to late-life reservoirs.

And what we see and with discussions of industry, the future wave in the Delaware Basin would be to drill for stacked pays. The economics are getting such that we need two or three targets in order to justify the drilling expenditures.

So you will see it as a new well and in original reservoir conditions. And it's not just for late-life salvage, as possibly it had been in, you know, the last thirty years. Again, many areas will rely on the stacked pay or the multi-target, or they just won't be drilled.

Q. Now, Mr. McClelland's presentation related to the Tubb, Blinebry and Drinkard formations, right?

A. Yes, that's right.

Q. Now, you will primarily relate to --

A. -- the Bone Spring, Wolfcamp and Delaware formations.

Q. Are there other formations that would be good candidates or --

A. Yes, as I've identified on the map, in addition to the Bone Spring, Delaware and Wolfcamp, the Strawn, the Atoka, the Morrow, all of these will and have been commingle targets and will be in the future.

Q. Have you done a study of the producing characteristics of these various formations?

A. Yes, I did.

Q. And what have you done?

A. Okay, I -- In the areas of these maps where I've seen -- where you see the red circles, which again are the areas we anticipate commingling for Delaware, Bone Spring and Wolfcamp, I got into the PI production data and pulled them up by township and compared the producing characteristics -- basically initial producing rates and the type of decline -- and found some pretty interesting things.

And then what I've done is pick out as an exhibit for several examples what a typical producer would look like. The things that we saw, that I saw in this study, was that they're predictable, they're very -- Throughout the Basin, you see much of the same type of producing characteristics in these. And we will provide some of those that you can flip through. That would be Exhibit Number 2.

Q. Right, you're referring to what we've marked as Number 2, right?

A. This is Exhibit Number 2, and I just -- I pulled out just a few typical wells. I did not want to spend a lot of time in them.

But generally they're very similar formations, and I'm going to go through a log here in a minute and show you that you're dealing with sands -- they're tight sands, porosities 10, 12, 14 percent.

The Wolfcamp and the Bone Spring are sands also that we've been dealing with now. Some of the Wolfcamps you get into carbonates, but again they're very low permeability and porosity, and so they tend to exhibit the same type of characteristics on producing: generally, 50- to 100-barrel-per-day average on the first month, hyperbolic declines, averaging -- they'll stabilize out in the -- oh, 30- to 50-barrel-a-day range, seems to be fairly typical, and not just for Delaware but for Bone Spring and even the Wolfcamps that I looked at.

Again, I think the importance here is that when it comes time to allocate production, we've got a very large database, thousands of wells have been drilled to these targets in this area, the data is there, and I think that based on the predictability that we're seeing, with a little bit of well testing up front, you can have a very accurate allocation.

And also, it aids us in going into these areas where we're going to be targeting for drilling these, quote, marginal pays. But again, knowing their predictability, we can stack them and then we can count on enough reserves out of several zones to make it worth drilling for.

Q. Do you want to move on to what we've marked as Exhibit Number 3 and identify that for the Commission, please?

A. Yes, Exhibit Number 3 is a type log, and it's kind of a long one, but I'd like to walk you through the type log, and it will show you where each of the formations are in relationship to each other, and we'll talk a little bit about their characteristics.

And this is the James Ranch area, but -- and then when we got to the first Bone Spring sand, we included the Mesa Verde well, which is in the area where Texaco has their application pending.

And we start at the top, top of the Delaware-Brushy Canyon. This area here in the 6000- down to 8000-foot range is where most of the drilling activity for the Delaware has been in the last five years. Literally thousands of wells now have been drilled to it. Some very good finds, but along with that a lot of marginal economic production.

We've marked in yellow generally what the perforated intervals are, the producing intervals within the Brushy. And again these are typical and these are where the significant ones are.

And then right below the Brushy Canyon D you would go into -- within about 1000 feet, you go into what has been produced in the area now as the Avalon sand. It's an upper Bone Spring sand. This is also in the Texaco area.

Then we move on down to about, oh, the first Bone Spring sand, roughly 9500 feet to 10,000 feet. It also produces in the Texaco area. And we have seen decent shows in other areas, but because of its marginal nature we've kind of bypassed it. That is something that would be a lot of upside, given relaxed rules.

And then we come down to the third Bone Spring sand and the Wolfcamp sands. Now, notice here, this is -- in our James Ranch application, the Wolfcamp and Bone Spring is what we've already gotten approved.

Now, engineeringwise, I have thought these were basically the same deposition, they are both the same permeability type range of sand, same porosity. I believe they were probably deposited from the same system; so did our geologist. But there's OCD regional cross-sections, and the BLM also, and this shale right between the two of them is what they call the Wolfcamp shale. So to me, operationally they're the same; but regulatorywise, it forces them into two zones.

What is of significance here is that these deeper zones are not the most economic of the three pays. The Delaware most of the time is going to be, so now here's your dilemma, that you're forced to -- if you even decide to drill down to here, you're forced to either complete this, spend the completion dollars here, completion dollars here, produce it down to a certain limit that you've got to kind of guess.

Then you've got to shut it in, you've spent those dollars, now you've got to go up to the Delaware, and you've got to spend a third set of completion dollars. Now you're no longer really getting a return on this while you've produced your Delaware, until you've got it figured out that you're within the 80-barrel-a-day limit under the old rules.

The new rules are going to alleviate that problem. And I think, from what I've seen around the area, they'll alleviate the problem for 90 percent, based on upping the oil limits.

And let me go ahead and just mention the water limits, since that was -- We're proposing that it stay at twice the oil limit, so that way it's just tied to the oil limit. Whatever that oil limit is, twice the water, and -- just keep it simple, that's all.

What we've been through, then, is what we would call the shallower oil zones.

And then you start getting into the areas that were the magenta-colored areas on the map, primarily gas production. And I'll show you where they are, but I really don't plan on spending time on it, but that's the Strawn pays, the Atoka sand and carbonate pays, and then at the very bottom here is the Morrow production. And again, it's gas.

I think you can see from the logs there, again, this area, multi-pay, and multi-opportunities, given the right rules, multi-opportunities to commingle and to produce efficiently reserves that may not otherwise get produced.

Q. Could you move on to what we have marked as Exhibit Number 4, please?

A. Exhibit Number 4 is a summary of the application that we had presented in November for our three-pool commingling on an areawide basis. I did not really want to spend a lot of time on the specifics, except to let you know that it did meet the 50-percent rule on the pressure.

It -- first month -- If we were to commingle all three zones in here, the first month's average production would have been approximately two hundred and, I believe, eighty-six barrels per day. That is not what we asked for.

We intend to produce the Bone Spring and the Wolfcamp for up to three months, get a good, stable rate, possibly run production logs, gather the reservoir information. At that time, then, the production is down in the 50- to 60-barrel-per-day range. That would be the time that, then, we would want to come on up to the Delaware. If you look at -- and then produce it possibly three months and then commingle them all.

We were looking at approximately 124 barrels per day, is what we anticipated the maximum to be. It would seem reasonable, and I'll talk about the allowables a little bit later, but again, if you go to the three curves in the back here I wanted to show the significance, again, of -- The first one is the Delaware. We've got approximately five Delaware, six Delaware wells.

And the interesting thing is, even though they do have some different IPs right up front, initial production is a little varied, anywhere from 70 to 110 barrels per day.

Within a few months, almost all the wells have come right down into the same -- within 10-barrel-a-day producing rate. And that's very significant when it comes to allocating and protecting correlative rights, that we can really get accurate forecasts on these.

You'll see the same thing on the next page, with the Bone Springs sand.

And then at the time, we had isolated the Wolfcamp, and it was reacting just like we expected. It was reacting very similar to the Bone Spring sand but a little less productivity. Now, we had run some cores out there, sidewall cores, and it showed less permeability. So it all makes sense.

We came in for an areawide and we believe that in that three- to four-square-mile area -- We presented cross-sections, we showed the continuity of the pays, the log calculations are all very similar. And so for those kinds of cases, we think -- You know, it's up to us to satisfy the Commission on a reference case as to how large the area will be. If we present the data that satisfies an area, you know, 400 square miles, then so be it, as long as we've done our part and satisfied the Commission on it.

That's pretty much what we had as far as what I wanted to show you. Very predictable. We have not seen water compatibilities as a problem. Again, there's a huge database with Martin Water Labs and several others that you can call them up, and even if you don't have the specific well in the area, you call them up and they can get offset producers. And they have a huge database for water. They will run the water analysis, check for compatibilities right there. They can do it all on computer, and they'll know if you're going to be in a problem area or not.

I think that's pretty much it. I would want to, then, talk about some of the specific rule -- portions of the rules.

Q. Right. Generally what is Enron's position relating to the proposed amendments?

A. Again, we appreciate and support the efforts of the Commission and the Division and the committee, the industry committee, and we think that where it's headed as far as upping the oil allowables, et cetera, are great strides. They're going to provide a lot of benefit.

We think that it's going to improve the approval process, it's going to reduce paperwork and administrative loads on both sides.

It does not abandon or undercut the effective management and regulation of our reservoirs. And again, it will provide, you know, fewer hearings, and more of this can be handled in an administrative fashion.

Q. Now, specifically regarding the economic criteria, currently Rule 303 allows for administrative approval only where the zone is uneconomic. What is your position on amending that requirement?

A. We at first also could see no real reason for an economic definition in today's environment. And understand, possibly back 30 years ago, why, there might have needed to be one. Today necessitates some differences.

And so we thought, you know, no need for a definition. Your definition of "marginal", if it's left up to the company, pretty much each company is going to have different guidelines -- I think you've heard several -- to come in and either relate it to payout -- We accept the marginal definition, would be sufficient, as long as there's some leeway between companies, I think. We would not support it being just too strict or too definitive, I think.

We want any definition to be based on drilling costs and completion costs, not just look at it from a "you're already there and now you -- what's it cost to produce it, or is it economic?", but look at it now from a drilling cost and completion cost.

Again, many of the drilling locations are relying on several marginal zones together to meet the economic thresholds of companies, and I believe that if there are concerns for economics, that it's kind of covered under the oil-limits part of it, and we're going to talk about that.

Q. Regarding the reference cases, what is Enron's position regarding a reference-case requirement?

A. We like the idea of the reference cases. And for the Delaware Basin it's kind of new, it's going to be more of a new process for us. We understand that in the northwest it's -- the commingling has been going on, there's a lot of activity, and there will be differences between what their needs are, versus the southeastern oil and southeastern gas, possibly.

And so the reference cases will be a good forum to go ahead and bring up each area's specific needs, compare them to the statewide rules, make the necessary adjustments, but then allow for other companies to reference those and get administrative approvals off that.

Q. Do you think the reference cases should be full hearings or --

A. No, we don't believe they necessarily should. Again, the Examiners always have the discretion to -- if they determine that an area needs a reference case and one comes in, they can set it as a reference case. It just does not necessarily go that you have to have a hearing in order to have a reference case.

Or we would anticipate that an operator can go ahead and anticipate that this would be a reference case, and we'll just donate it as one. And as long as the Examiner is satisfied that all the conditions are met, I don't know why it could not be done administratively also.

And then the reference case is to be set out on some type of a log or a system to where a simple phone call -- or they're put out on the state reporters, and we'll pick up which ones are the reference cases and have those.

Q. Now, are numerical studies necessary in downhole commingling rules?

A. We think that some numerical standards are necessary in order to regulate. I mean, that's -- They need to be as broad as possible.

We think that -- You know, if you can achieve 90 percent of your cases administratively through the numericals, whether they're arbitrary or not, or whatever basis, as long as they're covering the great majority of the cases, you know, then we don't really have an opinion, if it's not hampering so much. But we would like them to be broad, and then we would like them also to be -- based on something that will help the industry.

And again, the example of raising this oil limit is that perfect example, that this will help the industry, and it will cover the great majority of the cases.

Q. But it's not your position that there should be no standards or there should be no regulation?

A. No, no, we believe that there should be.

Q. Could you describe Enron's opinion relating to the limit, oil limit?

A. Yes. Again, the tripling of the oil limit is a very good step, and it would satisfy, again, the great majority of the applications that we see in this area.

There were a couple of concerns that we thought of.

It puts a commingled well on a different playing field than just a regular single-zone well, because it -- in a couple of cases it actually gives a higher allowable to the commingled well. Now, there's not a lot of difference on the tripling, but -- ten percent or so.

We think one standard for drilling all wells, that simplifies things, and it would still be fair, and I think the testimony has shown that assigning the top allowable for the depth bracket of the shallowest zone is going, again, to accommodate the great majority of the applications. And so it does put fairness with other production that is not commingled, sets the same standard for all wells.

And the potential for abuse could occur, and I'm not saying we've seen any cases like this, but if an operator had a zone, say, at 7000 -- or 5000 feet and his top allowable bracket is 120 barrels a day -- and I'm not sure that's it -- if he can go down and find a zone at 10,000 feet where after we've tripled these, he gets 240 barrels a day, he could go commingle now and get to produce his shallow at 240 instead of what everybody else is going to have to produce at. And so we see it as a protection against abuse, even though we can't point to any specific incidents.

And again, the allowables are always subject to coming in for hearing. If you have an MER or special data, special case, you could always come into hearing and get it higher if the data supports it.

Q. Now, you had mentioned before that your recommendation regarding the water limit would be that it parallel the oil limit; is that right?

A. Yes, yes. Some factor of the oil limit, and just keep it simply -- Two times, I think, is what the current rule would allow, and we don't see any reason to change that.

Q. What is your opinion regarding the 50-percent differential in southeastern New Mexico?

A. The 50-percent differential in southeastern New Mexico, again, has worked for a great majority of the cases. I also anticipate that it will.

I think what -- The importance of a numeric rule there is that it does force the pressure-differential issue to be addressed. I believe that it's arbitrary and that it's hard to justify where it should be and that it would be better addressed under the crossflow provision of the rules. But either place, we do need to incorporate pressure data into our discussion of whether zones will crossflow or not.

Again, I think that in southeastern New Mexico we would say, let's go ahead and leave it and we'll live by it, and it has worked, and if there are certain cases where it doesn't work, let that be a reference case, and then we would agree with northwestern, as a reference case, if they have satisfied the Commission that they're no higher than the least pressured -- or the original pressure of the least zone, then let them have that. I think that would be sufficient for them.

Our case, again, is not so much a depleted reservoir here, but we're going to be getting into some original pressures where it could possibly force you, then, to produce this marginal lower zone at first for a given number of months or who knows, until you can get that pressure down, when really it didn't have to be.

But -- So again, the 50 percent, I think, is going to accommodate the great majority of the cases.

Q. So Enron, then, concurs with the Commission's recommendations regarding relaxation of the crossflow requirements?

A. Yes, we do. For what you've seen testified on the gas formations, gas is a lot less viscous fluid and it will crossflow much easier into zones and out of zones. But that's the good part: If it goes in, it will come out too.

And so what they've been saying, we agree with. And we have not seen crossflow be a problem in our experience. Tight oil sands generally can hold a large --

larger fluid level or can withstand more pressure of a column sitting against them than what their bottomhole pressure is, because of the tightness of the rock. And as a matter of fact, we do have to hydraulically fracture-stimulate virtually all the Bone Spring, Wolfcamp and Delawares in order to get them to produce.

So for our area, we don't see crossflow as a problem. Generally, I'd say most of the time, these wells will be on pump, you don't have market restrictions, you don't have the possibility of being curtailed like gas wells, you're going to pump your oil. And the pump goes down, it takes normally two days to get a rig out there and get it pumping again. So you're drawing the effective bottomhole flowing pressures down to a point where you should never really see crossflow, as long as you're producing it now.

The Commission has -- When we get our orders approving downhole commingling, there's always a caveat at the bottom that says that after a certain amount of time, if the well is shut in a certain amount of time, we have to notify the District, and we agree that that should continue, and then they can talk about it and, if it does appear like there would be a crossflow problem, do something about it. But I can't point to any time that's been a problem either.

Q. Regarding the fluid compatibility, do you agree with the proposed recommendations?

A. We don't see any reason to change the standards on --

Q. Okay.

A. -- fluid and compatibilities. We agree with the earlier testimony that that is an issue that every operator knows from day one that he's got to satisfy and that if he does mix improper fluids and precipitants result, then he's cost himself. And I think that's going to be obvious to anybody, whether it's mom and pop or a major.

So we believe that that rule has got to stay, and as long as that is satisfied and it doesn't cost much money to run the compatibilities -- What I would say, on an areawide basis, where we know the fluids generally aren't going to change and we have tested it maybe one or two wells in an area, then I would say that satisfies that requirement for that area, just like the pressure differential rule might be dropped for an area.

As long as we have satisfied the Commission in this area, we've presented enough data, then when it comes time for us to get our commingling approval on individual wells, I would say that we would not have to resubmit that. Simply the reference case should -- or the reference number should satisfy that.

Q. Does Enron support areawide downhole commingling in general?

A. Yes, we do. It's not a new concept, it's been going on for years. And again, the reference-case idea covers that and the two aren't real compatible, supplement each other.

Again, the predictability of the zones and if we can prove to the Commission that the allocations are good and we can fine-tune them with some actual production data as we're completing the wells, then having an area is a good idea, and it will reduce future paperwork and the associated hearings, et cetera.

Q. And when you say "fine-tune", you mean directly with the District or the allowable requirements, you know, when you -- you would acquire new data from your drilling and testing, and you would fine-tune your standards?

A. Yes, in our area, in the case when we came in, we're saying for a certain area that we want approval from the Commission to commingle the Wolfcamp, Bone Spring and Delaware. Now, once we complete that well -- Well, let me back up.

First of all, that tells our management, now, okay, this is a place I can count on a project, I can now plan that in this given area I get to go drill wells to a certain target depth, which is great. Now, I can start allocating human resources and other resources and start planning for that.

Now, once the well is drilled, then we have to use test data from the individual zones to come up with an allocation to properly allocate, protect correlative rights, and to provide tracking -- proper tracking of the reservoir information.

So we will send in what the allocation formula should be once we have tangible data to do that on an individual-well basis.

Q. This morning there was discussion of the downhole commingling form proposed in the prehearing statement. Does Enron support the use of that form?

A. Yes, we support it and we think it essentially covers all of the details that are necessary to satisfy oneself and the Division that it's the right thing to do.

Q. Regarding a notice requirement, does Enron support the proposition that a notice requirement should still be maintained?

A. Yes, and we differ with some of the earlier testimony in that this is going to be a newer area, that maybe we're a little lower on the learning curve, we haven't done quite as many as they have in the northwest, and we would certainly understand that within the northwest, that that could be dropped and there would be no problem.

In my discussions with a couple of the companies, and even Enron's opinion is, for right now we would like to keep the notification of the offset operators to the spacing unit where the downhole commingling will apply. We believe it ensures just a free flow of information. If an offset possibly know something or has a concern, then they can either call us or, if it doesn't get satisfied, take it to the Commission.

But we might want to revisit this issue in a year, and if it's running smoothly then we might be willing to drop it at that point.

Q. I'm going to ask you a couple questions now regarding the supporting data that's required with these applications.

Should the Division retain a checklist of the data an operator submits with its application?

A. Yes, and I think that the form that we're talking about satisfies that.

Q. What about a requirement of a 24-hour productivity test?

A. You know, that's okay. It's not a big issue. But we believe, instead of a 24-hour productivity test prior to each zone being commingled, that in order to allocate you have to supply what the producing rates of the individual formations were anyway. So that a statement of those rates basically will accomplish the same thing, and in accordance with setting the allocation percentages.

Q. Where does Enron believe that the downhole commingling applications should be handled?

A. We -- Again, that's kind of up to the Commission. We see positives for leaving it in Santa Fe's hands, for continuity, we agree, and it might help keep the guys that are making the policy decisions a little more educated, a little more informed to the pulse of industry.

But, you know, we can understand whatever works best for the Commission, we would with go on that.

Q. Mr. Cate, will amendment to Rule 303, as Enron recommends, result in increased recovery of hydrocarbons in southeast New Mexico?

A. Yes, we believe that substantial increases would be anticipated through drilling to deeper, previously thought to be marginal zones.

A little bit of education as this catches on, I think you'll really see a lot of activity. I think there has been maybe some misconceptions as to the rule's limitations prior to this, and management kind of had the idea -- I know ours did -- that if you're going to have to spend time going to Santa Fe on a hearing, that's taking away time that you're supposed to be prospecting and finding new reserves. We'd rather not -- just rather not do that. It's going to be a hassle, it's going to require time and resources.

And I think that's maybe a misconception, that now, with the higher oil limits, et cetera, we'll get over that, we can convince with one case or reference case that we can come in, it will allow for planning.

So yes, increased reserves through new drilling, through deeper drilling, drilling to marginal formations you would not have gone to before, the economic lives of each zone is obviously going to be extended, your operating costs for three zones are the same as one, so you'll get the end-of-life benefits that came with the old rule, and I believe that about covers it.

Q. So in general, the amendments to Rule 303 would be in the interest of conservation, the prevention of waste and the protection of correlative rights, right?

A. Yes, yes. We believe that -- again, with the guidelines, with the rules set forth, the amendments that are proposed, that they still satisfy enough conditions that you're not going to lose reservoir data that is needed to properly manage -- which is our joint responsibility -- properly manage our natural resources. And it will encourage more activity, yet safeguard against the loss of reservoir information and still protect correlative rights.

Q. Okay. Mr. Cate, were Exhibits 1 through 4 prepared by you --

A. Yes.

Q. -- or at your direction?

A. Yes, they were.

MS. TRUJILLO: Mr. Chairman, I offer Enron's Exhibits 1 through 4, and I have no further questions for Mr. Cate.

CHAIRMAN LEMAY: Without objection, Enron's Exhibits 1 through 4 will be admitted into the record.

Questions of Mr. Cate?

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Cate, let me clarify a couple of points.

On the 50-percent pressure differential am I correct in understanding that the operators that you have polled in southeastern New Mexico have not found that numerical limit in the commingling rule to be an issue of concern for them?

A. Yes, in the discussions -- I don't know how much detail has been given to that, but no, nobody had verbalized that they had had a problem with that rule. Even though it may be arbitrary, it really has not hampered the commingling efforts and wasn't expected to hamper future commingling efforts in this area.

Q. Do you have any comments or opinions on Mr. Daves' suggestion of a substituted rule for the 50-percent rule, which would be, as we've discussed, the original reservoir pressure of the lowest-pressured reservoir being commingled? Do you have any comments or point of view with regards to that change?

A. Yes, we would think that that should be for northwest -- a northwest area only, in a depleted area.

Again, we would see very many cases that that would be a detriment, whereas the 50-percent rule was not, and that is -- Let's say 6000 to 7000 foot you encounter original reservoir pressures. Generally, given standard gradients out here, you should have a 3000-pound reservoir. And if you want to commingle a zone at 10,000 feet, you should encounter 5000-pound reservoir.

If it's gas and you've got a correct backup to this datum in the Delaware -- I'm using that as an example, even though there's not much gas production -- but you don't get to subtract many pounds, you're still dealing with 5000 over 3000. You're going to have to produce, go down to this lower zone, which may be the marginal zone again, or most likely is, and produce it for who knows how long, until it's down to a pressure that will not be above the shallower zone.

Q. As a reservoir engineer, isn't your concern about the crossflow -- which the pressure differential is pointing towards, is it not? -- isn't the 50-percent rule an issue to have a sense of the magnitude of crossflow that's going to occur between the higher-pressured gas reservoir and the lower-pressured gas reservoir?

A. Yes, it is. I think generally we're dealing with marginal enough zones that they would tend to be probably lower rates, but long-term lower rates, fall down to a certain pressure that may kind of maintain in this certain area.

I would imagine, though, that if we did that, you'd have a lot more hearings than necessary.

Q. I didn't make myself clear.

If you're looking as a reservoir engineer at the crossflow issue --

A. Oh.

Q. -- aren't you really looking at whether or not the crossflow is going to be of such a magnitude in terms of pressure that you're going to fracture the container with the least pressure?

A. Yes, yes. Now, I do agree with --

Q. Now, you and Mr. Daves agree, then, on engineering analysis as to what you're trying to examine?

A. Yes, I'm with you now, yes.

Q. All right.

A. In that instance, yes, I would think that would need to be a limit.

But here's the difference between -- Mr. Daves is -- He's just saying the bottomhole pressure of the shallower zone. But we know through drilling operations, through fracture treatments, what the parting pressure is. And sometimes it can be several hundred to a thousand pounds higher, because the rock that you're dealing with --

Q. Let me make sure that you understand what his proposal is. His proposal is that regardless of where you find the container at depth -- Normally, the shallower the depth, the lower the pressure?

A. That's correct.

Q. But his rule will be the lowest pressured original reservoir will then be the maximum pressure limit for commingling.

A. Yes, I think in gas zones --

Q. And that's --

A. -- that is fair, although it does not really address the parting pressures of the reservoirs.

Q. Well, it's going to be less than the parting pressure?

A. It's always less. So a safety factor is there.

Q. So the rule, if you adopt his proposal, adopts a safety factor that's less than the parting pressure of the lowest-pressured reservoir?

A. Yes.

Q. All right. So that keeps you from that reservoir-waste issue?

A. Yes, sir. For gas reservoirs.

Q. All right, for gas reservoirs, explain to me how retaining the 50-percent pressure differential is any better engineering than what Mr. Daves proposes for -- substitute the pressure rule.

A. I can't, engineering.

Q. On those -- Let me ask you this. For the southeastern operators, those that you have polled, they are -- Enron and others are suggesting that the Division retain notice to offset operators around this spacing unit with a commingled well application?

A. Yes, sir.

Q. If I understood you correctly, you said that you liked that information because it was information -- You could see what they were doing and you utilize the information?

A. And vice-versa, we would also notify operators of what we're doing, yes.

Q. All right. Other than information-gathering, will you agree with me that getting that information as an offset does not trigger a correlative-rights issue for that offset operator?

A. Not in all cases. You know, I can imagine that there may be -- we have not had any cases where we've opposed or it has triggered a problem based on correlative rights.

In general, the zones that we're dealing with are capable or not even capable of producing just their spacing unit, or draining their spacing unit, so --

Q. Other than exchanging information through that process, can you see any other reason for retaining the notice rule to the offsets as it applies to southeastern New Mexico?

A. No, not really. It's information exchanged to keep both sides educated and make sure, I guess, that there is not a problem, that everybody is educated.

MR. KELLAHIN: That's all the questions I have. Thank you.

CHAIRMAN LEMAY: Additional questions?

Commissioner Weiss?

EXAMINATION

BY COMMISSIONER WEISS:

Q. Yes, sir, let me see. I'm concerned about the reservoir engineering aspects of it, not knowing where the oil came from, and perhaps that's not even important in marginal wells.

But we heard testimony here last month that the Delaware, as an example, has an immense amount of oil in it that's not going to be recovered by primary, and I gather from your testimony that's what you're addressing, is primary production?

A. Yes, yes.

Q. And won't be recovered by -- In the Delaware, maybe they get two or three percent of the oil in place by primary and maybe that much again by waterflood, but CO_2 has a real potential to increase it up to maybe four or five, ten times that much. And -- But that's expensive, you want to know where to put it.

And normally, people want to put the objectives where the oil is, and I don't see how you'll know unless you produce something out of these individual zones. I'm concerned about that.

I might add that on your exhibit here, this packet of --

A. Yes.

Q. -- we also heard that this initial Delaware Parkway field is a waterflood, and I think you referenced it as a primary production.

A. I --

Q. I don't know about the others. Maybe the others are waterfloods also.

A. Well, there are some that are floods. This curve right here, this well here is just an example. It's a typical well on primary. And you're right.

Q. But it's not a primary, is my point; Parkway is under waterflood.

A. Well, this lease doesn't appear to be. If it was, I think you would see the oil response curve. But I agree, the field is. Is that -- I agree, the field is.

Q. Yeah, and that would say something about your comments about all declines are uniform. I mean, if it's under waterflood, it's obviously -- that comment is not --

A. Yeah, and let me comment on that, or expand on that, that industry -- and my experience is that if you determine a zone is capable of the kind of reserves it takes to waterflood, you've got a good idea of that up front.

Q. I don't think you learn that in a DST.

A. No, no, I mean -- but with production data, and that's --

Q. Precisely, you have to know where it came from.

A. Yes, and that's what we're saying. We do give actual individual well tests while we're completing these zones. And based on these IPs and the first couple of months of production, you can pretty much now start to type curve this.

Q. Okay. Well, I didn't understand that, I didn't understand that you were going to produce these different zones for a number of months or until you establish a trend.

A. That's right.

Q. That's your intention?

A. Yes, it is.

Q. Okay, that's my only question. Thank you.

A. Yes, it is. And one of the interesting things you can do these days -- The technology is great.

But on the zones that are still capable of flowing, which we saw in the Wolfcamp-Bone Spring production logs -- and they're spinner survey but they also have capacitance tools, temperature tools, and they put all this in a computer program and can tell you accurately what amount of fluid and what type of fluids, oil, gas and water, are coming out of each individual zone.

Now, it is harder to do when you are pumping. And now what the industry is doing is sulfur typing, fingerprinting of oils to see --

Q. That type of information is usually proprietary. I mean, you can't go to *Dwight's* and get that information. If I'm an operator on that end of the field and I'm contemplating some kind of a recovery project, secondary or primary, these things are not normally available to --

A. There is a lot of that, now, if the operator -- and you have to assume that they will provide the proper allocation. Then over time, you would be able to see that this one zone really is the best zone because of allocation which -- assuming it's correct.

Q. Unless there's some production history associated with that allocation formula, some trend, other than DST or some IP, you know, or 24-hour test or something?

A. Yes, that's correct.

Q. That's a tough one.

A. I think that the number of wells that have been drilled and the basic continuity of the pays -- You drill a well anywhere out here, you know what reservoir pays you're going to encounter. The question really is now quality. Did you get oil in it? Now how much will you produce? Those are really the only questions here now that we have to deal with.

You've got excellent simulation abilities now with the computers. I mean, we can put in our -- One thing Enron does is, we sidewall core the Delaware, and that gives you your permeabilities, your initial saturations. You can put a lot of sidewall core, waterflood simulations on it, and then put this in the computer and get a real good idea of whether this zone will be capable of waterflooding or not.

And we agree that you encounter a zone that is that good, you don't really need to commingle it, see? And generally you can tell. We know the zones that are capable of flooding. Generally they're Cherry Canyon zones, which are not -- they're the next set of pays up from this Brushy Canyon. I don't know of any Brushy Canyon secondary projects right now. It seems to be a lot more laminated, more water production. And if the CO_2 works in the future, there's nothing that says you can't come back to it now and isolate these zones.

Q. But the point is, you have to know these zones?

A. Yes, yes, I agree. But I think we've got a real good handle from a broad base of producing characteristics. And again, if you collect your data and get your sidewall cores and get some actual tests, which is exactly what we're saying we'll do to provide the allocation, you should be okay.

COMMISSIONER WEISS: Good, thank you.

CHAIRMAN LEMAY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Does Enron try to avoid commingling of sweet and sour zones?

A. It would depend on -- We haven't actually done that. Everywhere here that we're talking is all sweet crudes, and they're generally the same gravity, like 40- to 43-gravity crude. And so mixing them doesn't help or hurt our oil price we get for it.

You'd want to do an analysis, have the two crudes mixed, and let a lab tell you if there's any problems. I'm not real sure. I don't have that personal experience, we haven't done it.

But between a sour and a sweet crude, I think the problem might be that you could get a lesser price for it, because of the way it's mixed. It would depend on the mixing ratio and which refinery you finally get the crude to. So we don't have experience doing that.

I would say that as long as it doesn't hurt your oil price and you've analyzed it and it doesn't cause any precipitants or anything like that --

Q. It's not been a factor in your experience, within ops?

A. No, it hasn't. I don't know if it's been -- I don't think so.

COMMISSIONER BAILEY: That's all.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. One question, Mr. Cate. The -- When you're talking about these zones -- Bone Spring, Delaware, Wolfcamp -- I guess I get a little nervous by speaking of these formations.

You're right, you can go into Bone Springs, you have some scarp declines there. That's a carbonate, dolomite, that's going to react a lot different than either first, second or third Bone Springs sand.

A. That's true.

Q. You get in the Wolfcamp, you're only talking about the top. You get down in it, you've got all kinds of reservoirs in there.

A. Yes, you do.

Q. Your commingling orders, would you have objection -- Or let me throw this out. Where we allow you to commingle zones in the Bone Spring, Delaware and Wolfcamp, is it understood that we're speaking about -- we allow you to commingle correlative zones rather than the formations themselves?

A. I would not have a problem with that.

Q. When we're talking about the San Juan Basin, we're talking about more layer-cake geology. We can talk about the Pictured Cliffs anywhere in the Basin, and it's not going to change character. It's a defined interval.

You talk about the Wolfcamp, you're changing everything in terms thickness, in terms of reservoir rock throughout the Wolfcamp --

A. That's correct.

Q. -- and that tends to happen in the Bone Spring also. Delaware less so. You've got sands but certainly over a 4000-foot interval you have different zones.

A. Yes, that is correct. And assuming that the reference case is the -- I think I'm following you, that if the reference case is for a sand within the Bone Spring and not a carbonate, then it should not be able to use that reference case for a carbonate. And I agree, yes.

Q. And even when you're talking about some of the other characteristics, I'm not sure -- You were right when you pointed out that sand zone in the upper Wolfcamp being probably closer in depositional environment and every other characteristic to that lower Bone Spring sand, than even zones within the Bone Spring would be.

A. Yes, that's --

Q. So you're right, our formations are geologic-age formations, and I know where we say -- We attach Wolfcamp, we don't necessarily segregate the zones in the Wolfcamp, and that -- You can actually commingle the whole Wolfcamp and be able to do that under our orders.

A. An oil and a gas zone --

Q. Yeah, yeah, right.

A. That's right, we sure don't want to get into that.

Q. Well, you commingle a whole lot. I mean, we've talked about -- The Mesaverde has some of that characteristics.

I don't want to redo the way we do things. I'm just raising the issue that when we talk about granting commingling within these various formations, are we talking about only the producing zones, or maybe new pays that may be discovered within these formations?

A. Yes, and I think -- You know, again it's up to the operator to convince the Examiners and the Commission, and if there's any question at all, it just takes a phone call or kick it to a hearing and come show us.

And again, though, if I could demonstrate to the Division that it's not exactly the same sand, but it's a sand that it's a similar porosity and various --

Q. Same pressure?

A. Yeah, same pressure, you know, because we get a lot of that within a 100-foot interval. Sometimes you've got some of this going on. I mean, that's just geology, and in a reservoir that's what you deal with.

So as long as it is similar to what was presented in the reference case, I would say yeah, we ought to consider that. And if it's a different deposition --

Q. In response to Mr. Kellahin's question on, I guess, the reservoir characteristics on commingling gas and not having the pressure of one zone exceed the original reservoir pressure of the shallowest or weakest formation, that doesn't apply to oil; you're saying that oil -- I guess as long as you keep the fluid off the various zones, you don't really have a problem with that?

A. That's right, artificial lift, yes.

Q. Yeah, when you're on artificial lift, your pressure differentials, unless you're going to cover the -- well, even then, you've got just got a fluid column then?

A. Yeah, and not much of one. You know, your bottomhole pressures on pumping wells generally are 800 pounds down to 500, depending on where you are in the life of the reservoir. So --

Q. So you consider the pressure -- the 50-percent differential in oil zones in southeast New Mexico to be kind of a non-issue --

A. Yeah --

Q. -- or are you still recommending that we keep the 50 percent in there?

A. Well, yeah, I mean, I'm not agreeing that it's -- It's not an issue, because it doesn't hamper us. But again, it can't be technically justified. I don't know --

Q. I thought that was it. I'm just trying to clarify --

A. But I don't see it being harmed, to leave it in there, in southeast New Mexico. I'd recommend that we do initially.

CHAIRMAN LEMAY: All right. Commissioner Weiss, do you have any --

COMMISSIONER WEISS: No, I have no other questions.

CHAIRMAN LEMAY: Any other --

MR. KELLAHIN: Mr. Chairman, a point of clarification.

CHAIRMAN LEMAY: Yeah?

MR. KELLAHIN: The 50-percent differential --

CHAIRMAN LEMAY: Yes.

MR. KELLAHIN: -- is only on gas-gas commingling --

CHAIRMAN LEMAY: Oh, okay.

MR. KELLAHIN: -- that's not the oil-oil rule.

CHAIRMAN LEMAY: Oh, I'm sorry, I didn't know that either.

MR. KELLAHIN: It's not in the oil-oil --

CHAIRMAN LEMAY: So it is a non-issue.

MR. KELLAHIN: Yes, sir.

CHAIRMAN LEMAY: Well, we don't have to fix that one, it's already fixed. Good.

Anything else?

You may be excused. I thank you very much.

THE WITNESS: Thank you.

MS. TRUJILLO: Thank you.

CHAIRMAN LEMAY: Thank you very much, Ms. Trujillo.

I think we've decided because you've got a -- You might want to wind it up here, Counsel, but I do believe we talked about -- you have a survey out to the New Mexico Oil and Gas Association, and there may be some additional comments?

MR. KELLAHIN: Let me suggest a procedure, just as a suggestion.

CHAIRMAN LEMAY: Please do.

MR. KELLAHIN: We struggled with trying to craft a rule, and we felt that there were too many policy decisions for the Commission to make to draft a rule.

I don't think the rule drafting is all that difficult, once you make the policy decisions. And so we were going to suggest to you that if you want to enter an order with findings and conclusions about those policy issues, one of those conclusions would be a direction to the Division, either with or without our help, to draft the rule, as well as pursue the adoption of some form or set of instructions or engaged in discussions about the guidelines for the reference cases.

And so you might consider drafting an order that does not yet adopt a formal rule, and delegate to the Division or us or some group the assistance if you desire to draft the rule. You may decide that you're comfortable with what you've heard and you want to draft the rule now, so that's an alternative.

The other thing is, we would like guidance on the reference case. I think everybody is comfortable with that concept, and we're suggesting that you might set the standard with Mr. Daves' presentation, and so we're asking on behalf of Meridian that the Commission could use his presentation in the San Juan Basin to give us a reference case with regards to the Pictured Cliff, the Mesaverde, the Dakota, on two issues.

One issue is, he's seeking to have the 50-percent pressure differential deleted as part of his reference case, and so that future cases for the commingling of those pools are not going to have to be limited by that 50-percent rule.

The other thing that he's asking you out of this reference case is to make the finding that the commingling of these old reservoirs no longer presents an economic issue and that he'll have a reference case by which he no longer has to satisfy this economic standard if that stays in the rule.

We have circulated a questionnaire to the industry through the Association. That questionnaire is appended to the prehearing statement. We have asked that the companies respond by February 10th so that we will have that tabulated for submittal to you at your February hearing.

And you might, if you desire to do so, close this presentation in February with the submittal of any other comments and with the questionnaire. You might decide that you want to enter an order.

The actual language of the rule could be published on a docket, and we could come back and help you fine-tune a rule based upon whatever policy decisions you make in dealing with this general topic.

CHAIRMAN LEMAY: Do any of you want to make any statements prior to our -- Mr. Bruce?

MR. BRUCE: No, sir.

CHAIRMAN LEMAY: Okay, I think we'll continue the case until February 15th.

That's -- I want to put a plug in for that hearing. It's not only a proration hearing, but it's our "Industry Speaks-Commission Listens" hearing. We're going to repeat that this year.

It was very helpful last year. In fact, I'm gaining some statistics now to show how helpful it was, because the Division has ended up adopting just many, many of your recommendations at that hearing.

So we feel that's a good informal-type situation to present new ideas, policy direction for us, and it's your agenda. So think about that, and hopefully you will plan to attend that. That's only a plug for the hearing, and if we put this other case on the docket, that might bring you out too.

As far as I know, the only opposition to your recommendation has been from the Santa Fe Hotel, Motel and Restaurant Association.

MR. KELLAHIN: There's a lawyer group forming, Mr. Chairman.

(Laughter)

CHAIRMAN LEMAY: I understand in the mail there is a lawyers' coalition that is opposing this in general principle.

But we would be happy to reconsider this in February, with some of the results that you're going to have from the -- Anything else you want to bring up? I mean, this is informal; that's why we've tried to get all the ideas on the table. And I think we can give you some policy direction; that's what you want.

As far as the rules, I need to talk to my fellow Commissioners, whether they feel comfortable enough to even give you rules at this point or whether we want to put that back on you. But --

MR. KELLAHIN: Well, and that was my suggestion, is, if you're comfortable in deciding the policy you could decide that and postpone the actual rule once we come back to you with our effort to execute your policy decision.

I would like to invite those members of the industry committee that have participated with me to make statements now on behalf of their own company if they desire to do so, in case they cannot come back in February. Did you want to say anything?

MS. STALEY: We'll be back.

MR. KELLAHIN: They'll be back.

CHAIRMAN LEMAY: Good. Well, you were helpful last year. You'll all be back?

MS. TRUJILLO: I have one concern or question.

CHAIRMAN LEMAY: Yes?

MS. TRUJILLO: There are some downhole commingling applications pending.

CHAIRMAN LEMAY: Yes.

MS. TRUJILLO: Enron has one, Texaco has one, I know.

CHAIRMAN LEMAY: Yes.

MS. TRUJILLO: We're concerned about having them held up during the process of rulemaking, which could go on for quite a long time.

CHAIRMAN LEMAY: Well, I think that most moves us along fairly fast with the policy considerations.

There is a problem. I've talked with some of the representatives here, with the companies that have applications pending. Our problem is, we need the policy in place before what follows.

So the policy, I think we can certainly, hopefully, put in place so that those applications can be addressed.

MS. TRUJILLO: And I know --

CHAIRMAN LEMAY: But I hope you understand that the problem we face as a Commission and also my dual hat as a -- you know, as a Commissioner, as well as Director of the Division, I don't really want to get the Division making policy.

MS. TRUJILLO: And I know on behalf of Enron, they would be willing to adjust their presentation to meet the policies if necessary. Or, you know, from what you've heard today, that could --

CHAIRMAN LEMAY: I think they have. I think that's why they're here, isn't it? So they can give their viewpoints just for policy consideration?

MS. TRUJILLO: Right.

CHAIRMAN LEMAY: Over and above what they've applied for at the Division level.

MS. TRUJILLO: Right, they were asked to come in just to represent the southeastern area.

COMMISSIONER WEISS: Perhaps a decision could be made in the current policy if it's required.

CHAIRMAN LEMAY: You mean if there was enough policy in place that --

COMMISSIONER WEISS: No, if these pending cases have to be decided today, do it with the current rules.

CHAIRMAN LEMAY: I don't think they have to be decided today. It's kind of like as quick as possible, or the quicker the better or -- you know.

COMMISSIONER WEISS: Well, we're just pressuring you up.

CHAIRMAN LEMAY: Well, a little bit. Give us a decision.

Anything else?

Well, thank you. We'll take this case under advisement.

The record is open. Any of you that want to submit written comments between now and February -- I need to find from my fellow Commissioners the options that you've suggested for us.

We'll adopt one of them. At this point I can't tell you which one.

MR. KELLAHIN: Thank you.

CHAIRMAN LEMAY: Thank you.

MS. TRUJILLO: Thank you.

CHAIRMAN LEMAY: Thank you.

(Thereupon, these proceedings were concluded at 3:58 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 January 25th, 1996.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998