NEW MEXICO OIL CONSERVATION COMMISSION

EXAMINER HEARING

SANTA FE, NEW MEXICO

Hearing Date JANUARY 23, 1997 Time: 8:15 A.M.

NAME	REPRESENTING	LOCATION
[illegible]	Byram	
W D Jaap	Phillips	Farmington
Pat Noah	PHILLIPS PETROLEUM	FARMINGTON
Dick Morrow	Devon Energy	Oklahoma City
W. Kellahin	Kellahin & Kellahin	Santa Fe
[illegible]	Valero Energy	San Antonio TX
JAMES STRICKLER	BURLINGTON RES.	FARMINGTON,
TRAVIS STICE	BURLINGTON RESOURCES	FARMINGTON
JOAN [illegible]	Burlington	Farmington
JAMES HORNBECK	" "	"
Doug Thomas	" "	"
James Bruce	Hinkle Law Firm	SF
William F. Carr	Campbell, Carr, Berge and Sheridan	Santa Fe
Bill Smith	Interstate Oil	Midland
Rich Doffenbaugh	Intercoast Oil & Gas	Tulsa

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NAME	REPRESENTING	LOCATION
Duke Roush	Nearburg	Midland
Jerry Elger	Nearburg	Midland
RANDALL CATE	ENRON O&G	MIDLAND
PATRICK TOWER	" "	" "
Mike Brown	Manzano Oil	Roswell
Larry Hunnicutt	SunValley Energy Corp	Roswell

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

APPLICATION OF BURLINGTON RESOURCES OIL AND GAS COMPANY FOR THE ESTABLISHMENT OF A DOWNHOLE COMMINGLING REFERENCE CASE FOR ITS CANYON LARGO UNIT PURSUANT TO DIVISION RULE 303.E AND THE ADOPTION OF SPECIAL ADMINISTRATIVE RULES THEREFOR, RIO ARRIBA COUNTY, NEW MEXICO

CASE NO. 11,685

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

January 23rd, 1997

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner, on Thursday, January 23rd, 1997, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

January 23rd, 1997
Examiner Hearing
CASE NO. 11,685

* * *

E X H I B I T S

Applicant's	Identified	Admitted
Exhibit 1	6	12
Exhibit 2	7	12
Exhibit 3	7	12
Exhibit 4	11	12
Exhibit 5	16	26
Exhibit 6	17	26
Exhibit 7	33	47
Exhibit 8	39	47
Exhibit 9	44	-

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A P P E A R A N C E S

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Santa Fe, New Mexico 87505

FOR THE APPLICANT:

KELLAHIN & KELLAHIN
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Santa Fe, New Mexico 87504-2265
By: W. THOMAS KELLAHIN

* * *

WHEREUPON, the following proceedings were had at 8:18 a.m.:

EXAMINER CATANACH: At this time we'll call first Case 11,685.

MR. CARROLL: Application of Burlington Resources Oil and Gas Company for the establishment of a downhole commingling reference case for its Canyon Largo Unit pursuant to Division Rule 303.E and the adoption of special administrative rules therefor, Rio Arriba County, New Mexico.

EXAMINER CATANACH: Call for appearances.

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

EXAMINER CATANACH: Additional appearances in this case? There being none, can I get the witnesses to please stand and be sworn at this time?

(Thereupon, the witnesses were sworn.)

JAMES R.J. STRICKLER,

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

A. My name is James Strickler, and I'm a petroleum landman for Burlington Resources.

Q. On prior occasions, Mr. Strickler, have you testified before the Division as a petroleum landman and had your qualifications accepted and made a matter of record?

A. Yes.

Q. What is your responsibility with regards to the Canyon Largo Unit, Mr. Strickler?

A. I take care of the land functions covering the Canyon Largo Unit in Rio Arriba County, New Mexico.

Q. As part of that responsibility, do you have data available to you to identify for the Division all of the appropriate interest owners entitled to share in production from any formation within the Canyon Largo Unit?

A. Yes, I do.

Q. In addition, have you made yourself aware of and familiar with the offset operators to the particular unit in question?

A. Yes, sir.

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

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Mr. Strickler, let me have you take a second, and let's look at the exhibits that you're sponsoring this morning.

If you'll turn to Exhibit Tab 1, and behind the tab if you'll turn to the first page, it's a notice letter, isn't it, sir?

A. Yes, sir.

Q. Describe for us how you went about determining the list of all the parties to whom notice was sent of this particular hearing.

A. We searched our Division order records and identified 122 owners, working interest, royalty and overriding royalty owners in the Canyon Largo Unit, which covers approximately 49,876 acres.

Q. As part of that process, can you approximate for us the total number of interest owners that were notified of this case?

A. We sent out notices to all 122 owners by certified mail on December 5th, which is 20 days before the -- our meeting today.

Q. Mr. Strickler, are you aware of the current Division Rule 303, which requires in the absence of approval by the Division that each administrative application for commingling of each well require that you send that application to each of the affected interest owners, if the production to be commingled is under separate ownership?

A. Yes, sir.

Q. In this case, for each commingled well, in the absence of permission by the Division, you would have to send in some instances as many as 120 notices per application?

A. That's correct.

Q. Is that an administrative process that you're seeking an exception for in today's hearing?

A. Yes, sir.

Q. Let's turn to Exhibit 2 and have you help us find the Canyon Largo Unit in relation to other known operations and communities in the San Juan Basin.

A. What you see there is the location map. The Canyon Largo unit is identified in yellow. Again, it's in Rio Arriba County. We're approximately 49 miles southeast of Farmington, New Mexico.

Q. Let's turn behind Tab 3 and fold out the first plat. When we look at this plat, Mr. Strickler, what are we seeing?

A. This is a Canyon Largo Unit -- unit map. It's outlined in the green dashed lines. It comprises -- Well, it's in primarily four townships, 25 North, Range 7 West and Range 6 West, and 24 North, Range 6 and 7 West.

Q. What is the approximate vintage of this unit?

When was it first established?

A. This unit was approved by the regulatory authorities in September of 1953.

Q. In terms of a percentage, can you give us an approximate percentage of the kinds of oil and gas leases that were consolidated for unit operations?

A. Yes, sir, the fee acreage is approximately 45,726 acres, or 91.68 percent of the unit.

Q. Is that federal or fee?

A. Federal, I'm sorry, excuse me, federal. The state acreage is 3029 acres, or roughly 6.07 percent of the unit. And the balance is fee acreage, 1120.65 acres -- 1120.65 acres, or 2.25 percent of the unit.

Q. If we turn back to Exhibit 1 and look at the first page of the Application, in paragraph 1 of the Application you have summarized the well count within the unit, have you not?

A. Yes.

Q. There is a correction necessary for the Gallup well count, is there?

A. Yes, sir. We've posted there 6 Gallup wells, and there are 59.

Q. Six Gallup wells would have been the Burlington-operated wells?

A. Correct.

Q. And 53 are operated, I believe, by Merrion Oil and Gas Corporation?

A. Yes, sir, they're the suboperator of the Gallup PA.

Q. All right, the rest of the well counts shown on that page are correct?

A. Yes, sir.

Q. What accounts, when we look back, then, at Exhibit Number 3 in the foldout plat, what accounts for its odd boundary?

A. The reason for the -- there was some contraction due to marginal wells that weren't included in the unit.

Q. Did you have the ability to identify the owners entitled to production for all areas of the unit, for all formations?

A. Yes.

Q. How were you able to do that?

A. We have a summary sheet, again generated by our Division order system, that identifies all the working interest owners. We were also able to capture the royalty and overriding royalty owners in the various PAs.

We looked at leases that were outside the Canyon Largo Unit, and we researched that, and there were common owners. There are large leases in the Canyon Largo Unit, primarily made up of federal lands, and so we were able to obtain this information.

Also, Merrion Oil and Gas furnished us their Division order records, since they operate as suboperator of the Gallup PA. So between the two sources we were able to capture all the ownership.

Q. So for those tracts which are not currently dedicated to any participating area in any formation, you still had a way to identify --

A. Yes, sir.

Q. -- and send notice to those interest owners?

A. Yes, sir.

Q. All right. Let's turn behind the foldout tab, plat, and have you identify the next series of exhibits for us that are contained behind Exhibit Tab 3.

A. The first map you see here shows a composite of all the PAs. And as we flip the chart -- This is the composite map. As we flip the chart, we see the Chacra participating area, which is in the northeast section of the Canyon Largo unit.

Then we also -- Then the next map covers the Mesaverde participating area, which includes one 320-acre area.

The following map is the Dakota PA, which again is on the eastern side of the Canyon largo unit.

And then finally we have the Gallup participating area that is in the center of the Canyon Largo Unit.

Q. Let's turn now to Exhibit Tab 4 and have you identify and describe the information contained behind that exhibit tab.

A. What we have here is a list of all the interest owners in the Canyon Largo Unit. Again, it totals 122 entities.

And behind that we have copies of the certified receipts. We sent out the notices by certified mail and we have copies of the receipts, return receipts, of those owners for your records.

Q. If the Division grants this Application, Mr. Strickler, you're seeking to accomplish the following, that when Burlington files an administrative application, fills out the form -- I think it's the 107 form, for an individual well, that if the ownership is not common for production in that spacing unit, you will not be required to send notice to those interest owners, having satisfied that requirement with this Application?

A. That's correct.

Q. If there are offsetting interest owners to that spacing unit, which are working interest owners or operators and which would otherwise not been notified, then you'll continue to send notice to those offset operators?

A. Yes, we will.

Q. That would probably occur only around the fringes of the unit?

A. Correct.

Q. And it would occur only if Burlington was not, in fact, the offset operator to that unit -- spacing unit?

A. Yes, sir.

MR. KELLAHIN: All right. Mr. Examiner, that concludes my examination of Mr. Strickler.

We move the introduction of his Exhibits 1 through 4.

EXAMINER CATANACH: Exhibits 1 through 4 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Strickler, what exactly did you guys send to the interest owners? Was it -- It was a letter, it appears, behind Exhibit Number 1, and the Application?

A. We sent a form letter to the working interest owners. I didn't include a copy of that in this exhibit. I can certainly furnish that to you, if you would like.

Q. Okay, so it's -- You simply sent a single letter?

MR. KELLAHIN: No, Mr. Examiner, the entire Application and attachment --

EXAMINER CATANACH: Okay.

MR. KELLAHIN: -- plus my cover letter went to all the parties.

EXAMINER CATANACH: Okay, the Application that's --

MR. KELLAHIN: Yes, sir.

EXAMINER CATANACH: -- behind the tab?

MR. KELLAHIN: Yeah, they got the whole thing.

EXAMINER CATANACH: Okay, got you.

Q. (By Examiner Catanach) And are you satisfied, Mr. Strickler, that you've identified all the interest owners within this unit?

A. Yes, sir.

Q. Have you had any contact with any of the interest owners regarding this Application?

A. We had one inquiry by Merrion Oil and Gas. They sent us a letter -- and I believe you received a copy of that -- concerning the allocation of the various formations that we will discuss later in the exhibits.

That was the only inquiry.

Q. Okay. I do not see a PC participating area.

A. You're right, and we -- we inadvertently omitted that, and I have a copy of that with me.

Q. Now, the -- If you could submit that, that would be good.

MR. KELLAHIN: We'll have to give it to you after --

THE WITNESS: Yes.

EXAMINER CATANACH: Okay.

Q. (By Examiner Catanach) The composite of participating areas includes just those five formations you've got listed?

A. Correct. The Fruitland Coal, there's no production in the Fruitland Coal.

Q. The participating area for the PC must be the most extensive one in the unit?

A. It is, it is, and I apologize for omitting that map.

Q. You stated there were actually 59 Gallup wells, and 53 are operated by Merrion?

A. Correct.

Q. If those 53 wells -- if any of the 53 wells that are operated by Merrion are commingled with other formations, will Merrion still be the operator of those wells?

A. Yes, sir, I believe so. We have a settlement agreement with Merrion, and if they have the largest ownership in those zones, then they will still operate, if their ownership decreases.

Q. Did you say there was no PA within the Fruitland Coal at this point?

A. No, sir.

Q. Are there Fruitland Coal wells? No, there are not?

A. Looking at the first map, I see one Fruitland Coal symbol in Section 4 of 24-6. That's the only one I can see --

Q. Okay.

A. -- in the entire unit.

EXAMINER CATANACH: I have nothing further of this witness.

JAMES M. HORNBECK,

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

A. My name is James Hornbeck, and I'm a geologist with Burlington Resources.

Q. Mr. Hornbeck on prior occasions have you testified before the Division as a petroleum geologist?

A. Yes, I have.

Q. What is your responsibility with regards to the Canyon Largo Unit?

A. I'm the project geologist.

Q. As part of those duties have you become knowledgeable and familiar with the geology of all the producing formations within the Canyon Largo Unit?

A. Yes, I have.

MR. KELLAHIN: We tender Mr. Hornbeck as an expert petroleum geologist.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let's take a moment, Mr. Hornbeck, and review the geologic displays that you've enclosed behind Exhibit Tab Number 5, and then let me talk to you about what you foresee as the future development opportunities within the Canyon Largo Unit for the various reservoirs.

Let's start with the Pictured Cliff. Take a moment and describe for us what it is we're seeing with the first display, which is this Pictured Cliff isopach behind Exhibit Tab Number 5.

A. The Pictured Cliffs isopach map submitted is an outline of -- it includes the Canyon Largo Unit outline, which is in red on these four townships.

The scale -- These are section lines, and a square mile is a section. Those are the smaller squares. These are Townships 24 and 25 north, 6 and 7 West.

And on them we have the gross thickness of the Pictured Cliffs interval, which is one of the producing horizons within the unit. The contour interval is 10 feet, and there are some slight variations in thickness across the unit from the southwest to the northeast, but only on the range of a 20- to 30-foot thickness difference in the overall thickness of the Pictured Cliffs.

Also included in this map is a cross-section that is submitted as Exhibit 6, which will give you a cross-section across the unit, illustrating the stratigraphic continuity of all the producing horizons in the Cretaceous.

Q. Subsequent to the hearing, if the Examiner chooses to look at the cross-section, describe for us what you conclude as a geologist about that cross-section.

A. Well, the cross-section is constructed and is interpreted by me to be representative of the formation -- the relationships in all the formations across the unit. It's constructed in a dip direction, which is perpendicular to depositional strike of all these Cretaceous pay zones. And if there were any significant changes in reservoir stratigraphy or quality, they would be depicted and picked up on this cross-section.

And it's my professional opinion that there is not a great amount of change across the unit in these horizons.

Q. For the Pictured Cliff reservoir, give us a sense of where the Canyon Largo Pictured Cliff lies in relation to the Pictured Cliff in the San Juan Basin.

Is there a pattern of productivity in the Pictured Cliff that can be mapped so that you would have a sense of the size and the shape where the better Pictured Cliff wells are located?

A. This Pictured Cliffs development lies along depositional strike, with some of the more prolific Pictured Cliff sandstone developments, the reservoirs that are productive of gas in the San Juan Basin.

Generally, for the most part, the better Pictured Cliffs is concentrated in the very northeast corner of the unit, and we are along trend to the shore -- the Pictured Cliff shoreline development, but for the most part landward and therefore not nearly as prolific reservoirs as further into the Basin to the north and northwest.

Q. From a geologic perspective, what do you see the opportunity to be for further development of the Pictured Cliff in the Canyon Largo unit?

A. Well, based on historical performance, the forward opportunities from this point would be marginal in nature.

Q. Let's turn to the next display and look at the structure map. You've included a structure map on the base of the Pictured Cliffs?

A. Yes, I have.

Q. What's your interpretation of structure?

A. Well, it's a fairly common theme for all horizons. There are additional structure maps included, and what we see is a very uniform monoclinal dip into the Basin towards the northeast with an average dip rate of about 100 feet per mile.

Q. Is structure going to be a component in the reservoir where you as a geologist are going to be able to pick well locations for further development based upon structure?

A. Structure will not influence this -- the Pictured Cliffs or -- As we go through the other structure maps you will see a very uniform dip, and therefore structure is not considered to be a significant influence on additional locations.

Q. Let's turn to the Mesaverde. Again, in the Mesaverde reservoir, we're looking at a gross isopach that you've prepared?

A. That's correct.

Q. The data on the map, is this data confined to data out of the Mesaverde reservoir?

A. That is correct.

Q. All right. So all the symbols in here indicate data points in that reservoir?

A. (No response)

Q. (By Mr. Kellahin) Is there a distinction between those dots that are black, as opposed to the well symbols that are open colored?

A. Yeah, yeah, it's a standard convention. This database that we used to construct this map includes deeper penetration. For example, the Gallup and the Dakota penetrations, which do have a Mesaverde pick on them.

So some of these wells are -- especially the oil-well symbols, the solid black circles, are Gallup producers that have to drill the Mesaverde and therefore have control points to be used in isopaching the overall Mesaverde thickness.

Q. So despite the fact that you only have five Mesaverde wells producing in the unit, you do have substantial geologic data on the Mesaverde reservoir?

A. That is correct.

Q. Based upon that data, do you have an opinion as a geologist as to the future development opportunities in the Mesaverde reservoir within the Canyon Largo unit?

A. Well, based on the penetrations and the well control, mud-log information that we have, there's limited opportunities in the Mesaverde, and it would be again considered marginal.

Q. Let's turn to the Point Lookout structure. Give us a quick summary of the significance of this display.

A. Well, it's just merely indicating that the

Mesaverde as a whole conforms with the Pictured Cliffs structure that overlays it. There's a gentle dip, about the same rate, into the Basin towards the northeast, at about 100 feet per mile.

And I guess I'll also say, the Point Lookout is one of the major markers in the Mesaverde, so it's a very consistent pick.

Q. Okay. Let's go to the Dakota. Identify and describe the Dakota isopach for us.

A. The Dakota isopach is based on significantly less data, because there are much fewer well control points.

What we've done is tried to take a look at all well control in the unit that have penetrated both the top and the bottom of the Dakota producing interval. Most of that is concentrated on the northeastern quarter of the unit, and what it shows is that there's a variance in thickness from anywhere from 250 to 280 feet, in gross overall thickness.

That's it.

Q. Is there a geologic explanation to the fact that in some 40 years of unit operations, you have very few Dakota penetrations in the unit?

A. Well, there have been a lot of attempts to make commercial wells in the Dakota over the course of the development of the unit.

What we see is that regionally, with respect to the major producing trends in the Dakota, in the San Juan Basin, we're out of some of the better bar developments and better reservoir developments, which are associated with the upper Dakota marine section, two wells in Paguate intervals, and those developments are significantly further away to the north and west in the more central portion of the Basin.

Q. As a practical matter, what do you as a geologist see to be the future development opportunities in the Dakota reservoir within the unit?

A. We feel that it's -- it will be a marginal target, and although we are taking a look at additional opportunities, hoping that there may be additional compartmentalization and opportunity, for the most part the conventional reservoir is still considered a marginal target.

Q. Burlington is still considering, then, the high-risk experimental Dakota well within the unit where you would drill that at least initially as in a stand-alone attempt in the Dakota?

A. Yes, that's correct.

Q. If that fails, then, you could still use it as a commingled well?

A. That is correct.

Q. All right. Let's look at the Graneros. What's the story on the Graneros structure map?

A. Again, it's a very uniform structural interpretation, based on the well control. This is a marker directly overlying the Dakota, the Graneros shale.

What it shows is, again, a very consistent uniform dip to the northeast at about 100 feet per mile, again, very similar to the other two overlying structural horizons.

Q. Mr. Hornbeck, we don't have a specific display on the Chacra. That is one of the reservoirs or the zones shown as a participating area on Mr. Strickler's map.

Can you give us a verbal representation of the Chacra? We might go back to one of his participating area maps, just to have a sense of where that Chacra development has occurred.

A. Exhibit 3.

Q. Yes, sir, it's the display that shows the Chacra PA and apparently all the participating areas confined to the northeast corner of the unit.

A. Yes, the Chacra participating area pretty much outlines a very excellent quality sandstone reservoir developed within the Chacra interval. And the Chacra interval is a sandstone stratigraphic trap that produces gas, sandwiched in the Lewis shale, which is in between the

Pictured Cliffs and the Mesaverde producing horizons.

And what we see there is that within that PA that's developed currently there is adequate reservoir thickness and good conventional matrix reservoir-quality sandstones, which are producing very, very good production histories for those wells.

About where that PA ends to the southwest, there's a rapid pinchout and shaling out of that excellent quality sandstone reservoir, and therefore to the southwest in the remainder of the Canyon Largo Unit we do not see that well-developed quality of reservoir, and it's marginal at best. Again, modern wireline logs, porosity logs and mud logs show us that it does not have nearly the productive potential as the wells developed within the PA that currently exists.

Q. Mr. Hornbeck, are you familiar with the Division rule that established the Chacra demarcation line in establishing the vertical limits in the Blanco Mesaverde Pool?

A. Yes, I am.

Q. And that line is generally north and east, I believe, of this area, is it not?

A. Yes, it is.

Q. So when we're looking at the Chacra here, we're not looking at a Chacra that is a portion of the Mesaverde

in a different portion of the reservoir?
A. That's correct.
Q. The Chacra in the Canyon Largo Unit is a distinct reservoir, separate from the Mesaverde.
A. That's right, south of the demarcation line, and it's truly a stratigraphic gas trap.
Q. Why has the Chacra development in the unit stopped at the participating area shown on the display?
A. It's related to a deterioration of reservoir quality.
Q. Do you foresee a reasonable probability that Chacra can be developed in the balance of the unit, as a viable reservoir target?
A. Based on the current well control and the information we have, it does not seem that that's an option.
Q. If you get lucky, you may find it. Otherwise, it's probably not going to be productive?
A. Well, there have been enough penetrations through it, testing deeper horizons, that we perceive it as being nonproductive. It shales out and becomes a very tight reservoir.
Q. Okay. Summarize for us your conclusions, then, as a geologist with regards to this Application.
A. Based on currently what we know within the Canyon

Largo Unit, future development of all the horizons that we have discussed will be pretty much in a marginal nature.

We are still considering ways to try and find additional opportunities in the horizons, based on improving technology. But right now, based on everything we see from a historical perspective, most of these zones will be marginal -- all of these zones will be marginal.

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

We move the introduction of his exhibits behind Exhibit Tab Number 5 and 6, 5 and 6.

EXAMINER CATANACH: Exhibits 5 and 6 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Hornbeck, you didn't discuss anything about the Fruitland Coal. Do you know anything about that within the unit?

A. Yes, I do. There's been some testing of the Fruitland Coal in and around the Canyon Largo Unit area, and as far as I'm aware, it is in the underpressured area outside the prolific productivity associated with -- further north in the Central Basin around the 30-and-6 unit, and there has not been a lot of encouragement with prolific rates and things like that in the Fruitland Coal, and it's been basically a recompletion target in deeper wellbores.

Q. There's only one Coal well in the unit, to your knowledge?

A. That is correct.

Q. Are any of these zones -- do you drill -- Do you still drill any stand-alone wells to test any of these zones?

A. The only potential at this time for a stand-alone project would be in search of gathering data for compartmentalized, separate sands in the Dakota. Other than that, there's no other horizon that warrants a stand-alone project.

Q. What do you see as the development within these marginal zones? Do you see that they're economically -- have the potential to where you can, say, drill a Mesaverde-Dakota commingled well, something --

A. Well, it certainly will improve the economics. And we will present some -- I will not personally present some information, but our reservoir engineer expert will be presenting some information that will show you the improvement when we are able to commingle some of these zones together.

Q. As far as the commingled situation within this unit, do you see that as maybe -- recompletions as being the majority of the wells you'll commingle within the unit?

A. Well, we would certainly -- You know, we would like to take advantage of any opportunities to improve recoveries, and there will be numerous attempts to commingle through recompletions.

We have currently a lot of wells that, based on liquids in some of the horizons, specifically the Gallup and the Dakota, and gas associated with the Dakota and the Mesaverde and the Pictured Cliffs, that we'd improve lifting efficiencies on the liquids and also hopefully attempt to improve overall recoveries out of all these zones.

EXAMINER CATANACH: That's all the questions I have, Mr. Kellahin.

JOAN M. EASLEY,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Would you please state your name and occupation?

A. My name is Joan Easley and I'm a petroleum engineer.

Q. Ms. Easley, on prior occasions have you testified before the Division as a petroleum engineer?

A. No, I have not.

Q. The microphone is just for the court reporter; it doesn't amplify your voice. So it won't help you, you'll have to speak up.

A. Okay.

Q. When and where did you obtain your degree?

A. I graduated from Mississippi State University in 1994 with a bachelor of science in petroleum engineering.

Q. Summarize your employment for us.

A. Since 1994 I've been employed by Burlington Resources in their Farmington/San Juan Division.

Q. And that's where you currently reside?

A. Yes, sir.

Q. What are your engineering responsibilities for the Canyon Largo Unit?

A. Since March, 1995, I have been an engineer in the area that manages the Canyon Largo unit, mainly in production engineering.

Q. As part of your responsibilities, have you made yourself familiar with past reference cases Burlington has filed with the Division and had approved by the Division?

A. Yes, sir, I have.

Q. And have you used the methodologies and information in those prior cases to aid you in your preparation for today's case?

A. Yes, I have.

Q. As part of your work, have you made an investigation of the cost components for the various reservoirs in the unit?

A. Yes, I have.

Q. And do you have an engineering opinion with respect to how to best further develop all the reservoirs in the unit?

A. Based on the information we've put together, all of the formations in this unit would be best developed in a commingled state to improve the economics.

MR. KELLAHIN: We tender Ms. Easley as an expert petroleum engineer.

EXAMINER CATANACH: She is so qualified.

Q. (By Mr. Kellahin) Let's talk about the reservoirs in the unit.

The Dakota reservoir, what is the current status of that development, and what do you as an engineer see as the future for further development in the Dakota?

A. The Dakota has a lot of potential throughout the unit. We have lots of open locations for the Dakota.

In the past, stand-alone Dakotas on average have been marginally economic due to lower reserves.

Currently we're planing to drill two tests, as Jim referenced, testing the compartmentalized lower Dakota that we're testing.

Other than that, any future development should be commingled, in order to make it economic.

Q. The well count in Pictured Cliff is about 140 in the unit?

A. Yes, sir.

Q. What do you see as the future development opportunities in the Pictured Cliff reservoir?

A. We've in the past -- not myself, but in the past we've basically developed the Pictured Cliffs. Any future opportunities would be tests in an existing wellbore or in a wellbore that we drill as another formation that we're adding.

Q. What do you see as the opportunities in the Fruitland Coal gas, within the unit?

A. As Jim said, based on what we've seen through the drill bit and wireline logs, et cetera, we don't foresee any development of the Fruitland Coal at this time, and it definitely would be marginal. It's probably the most marginal reservoir we have out there right now.

Q. Merrion Oil and Gas is the sub-operator of the Gallup formation?

A. Yes, sir, they are.

Q. And in what portion of the unit does the Gallup development occur?

A. Mainly in the southern part of the unit, what's called the Devil's Fort field and the North Devil's Fort field. Those wells are economic. It's an oil reservoir, basically, from two different Gallup formations.

North of that, we've had six tests, which are the six ones that we operate, and those have all been marginally too uneconomic.

Q. So when we move in other areas of the unit outside of the conventional historic oil production that's being produced by Merrion --

A. Right.

Q. -- then we're into a part of the Gallup that represents high-risk marginal production?

A. Yes, sir.

Q. The Mesaverde reservoir, characterize that for us in terms of future development.

A. Basically, anything there will be in a commingled status. We've done some dual wells and are currently hoping we can commingle those, because they are marginally economic as a dual state.

Q. And finally the Chacra?

A. Chacra, as Jim said, has been productive in the northeastern part of the unit. We haven't had any Chacra tests outside of the sweet spot, but they do look like they would be marginally economic, and we would develop those only in a commingled state.

Q. Have you prepared for the Examiner's benefit the cost components of drilling and operating wells in the various reservoirs and segregated it in such a way that we can illustrate and describe the costs attributed to a single completion, contrast that to a dual completion, and finally be able to characterize those two with commingled completions?

A. Yes, sir.

Q. Well, let's do that now. If you'll turn behind Exhibit Tab Number 7, take us through your presentation.

A. Okay, the first page we see is basically cost for Chacra, PC or Fruitland Coal wells. Basically, they're very close and similar in depth, and so this cost would be very similar.

Single completion total cost, on average, about $300,000; dual, $250,000; and commingling drops down to $209,000. We've broken those out into drilling completion facilities, tangible and intangible.

We've done the same thing for the Mesaverde.

Q. All right, let me see if I understand how you did this. If we look on the first page and I look under the dual completion column, I find the total costs attributed to the Chacra-PC-Fruitland of $250,000, give or take?

A. Yes, sir, and that would be the cost attributed to that formation.

Q. All right. If I want to take a wellbore and commingle PC with Mesaverde --
A. Okay,
Q. -- where do I get the -- I'm sorry, I want to dual it.
A. Okay, dual.
Q. I want to dual it with Mesaverde and PC. So I've got $250,000 attributed to the PC. What are my costs attributed to the Mesaverde?
A. Look under dual completion, and the total would be $351,000, and so the total would be $600,000.
Q. All right. So I've got a $600,000 wellbore for a dual in Mesaverde-PC?
A. Yes, sir.
Q. If I want to commingle those two, what's going to be my total cost?
A. Roughly $275,000 plus $208,000. So it would be $475,000, $480,000.
Q. Okay. And so you can use that method to make a comparison to see how the estimated costs compare based upon the type of well you want to drill and produce?
A. Yes, sir.
Q. Where did the cost numbers come from?
A. We took an average of all wells we have completed or will complete in the future for these areas, estimates

on what work has been done, and projected costs for the future.

Q. All right, and that's the kind of thing you would do not only for this hearing, but for your own information?

A. Yes, sir.

Q. These are current costs, they're based upon AFEs and estimates and bidding and all that process by which you assimilate information for costing wells?

A. Yes, sir.

Q. Once you have determined an expectation of cost, you also have to apply some type of rate of return or profit, minimum profit percentage, to the calculation, do you not?

A. Yes, sir.

Q. And what percentage did you use?

A. Twenty percent.

Q. And that is the percentage we've used before Examiner Catanach in past reference cases?

A. Yes, sir.

Q. All right. Once we have those two components, cost and a minimum-profit percentage, what have you done when we look at this curve that's got the blue, green and red lines on it?

A. Basically, we've run the economics for different cases of ultimate recovery and initial rate and plotted with those economic parameters this on a graph, so that what we can do is, if we have an average expected EUR and an average expected initial rate, we can take that, plot this on this chart and see under what circumstances this well would be above marginal economics, i.e., would dual, commingle or stand alone.

Q. In past presentations before the Division, we have urged the Commission to adopt and, in fact, the Commission has adopted, two components to identifying whether a well was marginal or not. It was an initial rate plus an estimated ultimate recovery.

A. Yes, sir.

Q. And you have done the same thing here in this case?

A. Yes, sir.

Q. Initial rate alone is not going to tell you if the well is going to be economic; is that not true?

A. Yes, that is true. I mean -- Yes.

Q. That is true?

A. Yes.

Q. Give us a sense on this display, when we're looking at the Fruitland, PC or Chacra, what you would forecast to be the point on the curve that you're likely to be placed for the development in those reservoirs.

A. Well, the average PC estimated ultimate recovery in this unit has been about 675 million cubic feet. The average initial rate has been about 120 MCF a day. And so if you take 120 MCF a day and plot it against 800 -- What did I say? 875?

Q. Yes, ma'am.

A. 675.

Q. 675.

A. 675. That plots just below even the commingle line. So we're talking about a very marginal reservoir that we would only develop if economic parameters improved.

Q. In order to meet your economic threshold, you would like to be above the red line?

A. Yes, sir.

Q. And you can't justify it as a dual well if it is below the green line?

A. That is correct.

Q. Okay. When you fill out the commingling form, you fill out and sign the form 107, you fill in the blank where it says that you forecast that particular zone to be marginal or nonmarginal?

A. Yes, sir.

Q. You would put the blank for the PC as marginal?

A. Yes, sir.

Q. And then you could attach this display to your application so the Examiner could see the basis upon which you've made the conclusion that that zone is going to be marginal, based upon your calculation of EUR and rate?

A. Yes, sir.

Q. Let's look at how you might do that if it was a Mesaverde zone in the well. If you'll look at the next curve.

A. On average in this unit, the Mesaverde estimated ultimate recovery for a single well is about 840 million, with an initial rate of about 260.

So if you plot 260 against 840, you come in between the commingle line and the dual line, meaning that this well would be economic or above marginal economics as a commingle, but as a dual it would fall below the marginal economic limit.

Q. And then the challenge for you as an engineer is to try to package these reservoirs into a multiple opportunity in single well, and with the total combination hopefully meet your economic threshold by which you can at least justify it as a commingled wellbore?

A. Yes, sir.

Q. Let's look at the Gallup economics, if you'll turn to the next curve. I've got the Gallup economic limit. Are you with me?

A. Yes, sir.

Q. Where would you forecast the opportunities for a

Dakota development to be if you were to test the -- I'm sorry, the Gallup, where would we fall on the curve?

A. This is plotted according to barrels of oil per day, because most of the Gallup production is oily. So average EUR is about 45,000 barrels of oil over the life of the well. Initial rates are usually around 14 or 15 barrels of oil a day.

So if you plot 15 with 44, it falls right on and just below the dual line, basically, just on the bottom side of the dual line.

So this one is economic, or above marginal economics as a commingle; it is almost on the line as a dual, but it still falls slightly below.

Q. Okay, let's look at the Dakota curves.

A. Same story, average EUR for Dakota is about 1 B, or a million cubic feet. Average rate is 196 MCF a day. So at the 200-MCF-a-day line plotted against 1 B, it falls even below -- at that initial rate, even below the commingled line. So it's on average throughout the unit a marginally economic formation.

Q. If we turned behind Exhibit Tab Number 8, Ms. Easley, let's look at the first spreadsheet behind that exhibit tab. What are you displaying here?

A. That's the information I've been referencing. What we did is took the population all the different formations in the unit, and basically listed or averaged estimated ultimate recovery, remaining recovery, average initial rates.

And also we listed what we -- the initial bottomhole pressures for all these zones before they were depleted were, and current bottomhole pressure conditions.

Q. All right. Again, when you fill out the commingling application form, part of the form requires you to disclose your opinion of what you think the original reservoir pressure is of the lowest-pressured reservoir to be commingled?

A. Yes, sir.

Q. You would fill a blank in, and then you could attach this sheet to your application, so that Mr. Catanach could see how you went about deriving that information?

A. Yes, sir.

Q. Or you could also supplement it and attach the immediate offset pressure information if that was appropriate?

A. Yes, sir.

Q. Those would be judgments you would make as the reservoir engineer that is signing off on the form, having attested to the fact that you have authenticated all the information that is shown to the Division on that form?

A. Yes, sir.

Q. Let's thumb through the rest of the picture display showing pressure so that Examiner Catanach understands what you're trying to illustrate to him with the subsequent displays behind Exhibit 8.

A. We have four maps here, two for the PC and two for the Dakota. The reason we chose these two are, these are the two formations that currently we would definitely not be able to commingle due to the pressure situation.

The first is a contour map of initial pressures in the PC. It ranges from 700 p.s.i. to 900 p.s.i. bottomhole pressure.

The next map is a contour map of the current pressure in the PC, which is about 200 pounds, 200 to 300 pounds.

And so the initial pressure of the lowest-pressured formation currently in the unit was 700 pounds.

And the next map is Dakota initial pressure, 2700 to 2800 pounds. And current pressures in the Dakota with the information we have is about 800 to 1200 pounds. And so that's above the initial pressure of the PC. And we're just illustrating the fact that we definitely would not be able to commingle these two zones because of the pressure requirements.

Q. If the Division decides it's useful to use the unit concept in which to package data for processing commingling applications, then this would be a way to review that information?

A. Yes, sir.

Q. It is not intended to be an exception from the pressure limitations in the current rules?

A. Right.

Q. If we get a Dakota zone that has a higher pressure than the original bottomhole pressure in the Pictured Cliff reservoir, if that's to be the commingled zone, then obviously you can't commingle unless you get special relief?

A. That's correct.

Q. Let's talk about the allocation formulas. Let's start with the issue of Merrion and Burlington each dealing with a particular type of reservoir substance, one has got an oil component in the reservoir, and you may qualify it with gas.

How are you going to handle the allocations, and what will you do?

A. In our informal discussions with Merrion, what we've determined is that if we had two reservoirs producing similar streams, like a gas combination or an oil-oil combination, but not gas-oil, we'll go with what we've historically done, which is a fixed percentage method, which we've established with the NMOCD in Aztec and with the BLM.

If we have mixed streams where we have oil and gas produced together, what we've discussed with Merrion and what we anticipate doing is going to a BTU-adjusted fixed rate percentage. And in that instance what we would do is take the common BTU value of the combined streams, and we have known values for the separate streams, and through a calculation figure out what percentage is coming from one formation and the other.

And we do the same thing with gravities for oil, so that we get a fair representation of each formation and the optimum revenue from each stream, based on these things.

Q. In all instances, will the commingled production have a value equal to or greater than the value of the separate production?

A. Yes, sir.

Q. Yeah, you --

A. You can't --

Q. We're not permitted to commingle zones --

A. Right.

Q. -- in such a way that we result in an ultimate commingled product that's worth less than if you had produced them separately?

A. That's correct.

Q. And so this is not going to cause that to occur?
A. No, sir.
Q. Let's look at the illustrations of the allocation methods for the Examiner so that he can now see specifically the methodology you're proposing for optional methods of allocating production within the Canyon Largo unit.

If you'll turn to Exhibit Tab 9, let's look at the first display.
A. Basically here we've just documented very simply the two different methods that I just mentioned.

The first one is performance fixed percentage for similar streams, and it's just based on past historical performance of an existing formation that we're commingling with another one. Or if it's a new drill and both formations are -- you know, new completions, the production tests that we've established with the NMOCD and the BLM as being acceptable.

The next method would be the BTU adjusted, for the mixed streams. And we just went through a simple calculation there where we just showed an average -- our initial rate of 100 MCF a day and a BTU content of 1245, and just setting that up with the known values for both the Dakota and the Gallup, which are our example formations, we come out with a 44-percent allocation to the Dakota and 56 to Gallup, based on BTU content.

And that should accurately represent the contributions from each reservoir.

Q. Okay. The Division has expressed recent concern that some of the administrative applications being filed were not sufficiently complete so that the application could be reviewed without a lot of research by the Division to go and look up supporting information.

The concern was expressed that the use of the reference case had been misunderstood, whereby the applicants were using the reference case and not giving sufficient supporting documentation.

A. Right.

Q. When you file these for your unit, will you provide the necessary documentation to justify the allocation formula so the Division doesn't have to do your research, and so they can look at the Application as a stand-alone application?

A. Yes, we will.

Q. If they desire to have more information, they could look at this reference to this transcript, and if that's not enough then they certainly can call you or ask you for more information?

A. Yes.

Q. Let's turn, then, to this second page and see the last part of your discussion with regards to the BTU content. Set this up. What are we looking at?

A. Basically, this is just an illustration of the consistency and constancy, I guess, of the BTU content of the different flow streams. It's 1988 to 1996, and we just pulled BTU analysis from those years and made this graph.

It shows over a period of eight years, basically, the BTU content has remained very constant.

BTU content is another thing that's very easy to go do a check on. We have to because we sell gas based on BTU content to get our price, and so therefore this is going to be that will be constantly updated.

Q. Give us a summary from your perspective, Ms. Easley, of what the advantage is in the unit of engaging in a development plan that uses commingling as a major strategy for extracting those resources from the units

A. Sorry, repeat the question, please.

Q. Yes, ma'am. Give us your engineering summary of the advantages you see in having the Division approve this Application.

A. Based on what we've seen in this unit, the formations, all six that we've mentioned here today, are marginally economic as a stand-alone or a dual. In order to access all the reserves in the unit and produce them in a prudent matter, we do need to be able to commingle these zones to get maximum economic impact.

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

We move the introduction of her Exhibits 7 and 8.

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

EXAMINATION

BY EXAMINER CATANACH:

Q. Ms. Easley, I have not seen the BTU allocation before now. Is it something that you would just -- would you use this in conjunction with some other data, some other production history or testing data, or just simply this formula here?

A. What we plan to do is that on new drills, for instance, we are required to do the production tests that we've established, and so we would use that production test, and what it tells us in conjunction with the BTU-adjusted fixed percentage to make sure that they check each other. There's an obvious difference between the two, there would be reason for us to look at it further before we submit an allocation formula.

Q. Okay, so you will use other data besides this?

A. Yes, sir.

Q. Okay. Your initial producing rates and your EURs were all calculated from existing wells within the unit?

A. Yes, sir.
Q. I'm lost. Where is that at?
A. That spreadsheet?
Q. Yeah.
A. It's right behind Exhibit 8, first page behind Exhibit 8.
Q. Here it is.
So for example, you've taken all the Pictured Cliffs wells within the unit, and you've averaged their initial producing rate and EURs to come up with these numbers?
A. Yes, sir.
Q. Okay. Where you don't have a lot of data, how confident are you in these numbers?
A. Well, obviously if we don't have a lot of data, then there's always the potential that we'll find something different.
And then some of the more risky Dakota wells that we've drilled in the last year looking for that lower Dakota, we have encountered higher pressures than the current ones that are listed here. In that case, obviously we wouldn't be able to commingle those if they're higher than the other formations.
So there will be exceptions to these without a doubt, especially if the less developed formations like the

Mesaverde and the Dakota and the north part of the unit in the Gallup.

Q. In those -- In the Dakota tests that you were talking about, did you encounter higher initial producing rates?

A. In one well, out of 11 or 15 that we've completed recently in the last few years, and it did have a much higher rate and much higher EUR. It was the exception, though.

The other wells were -- fell into this average. And actually, that well was the lower Dakota that we're looking for.

Q. As far as the other formations are concerned, do you feel like the numbers that you would get in subsequently recompleted wells are similar to those you have listed here?

A. Yes, sir.

Q. They're not going to vary much?

A. No, sir.

Q. As far as the pressure data that you supply on the applications, you're not going to simply provide the pressure data that you've got listed here. You're going to -- Say you've got a recompletion.

Are you -- You're actually going to supply the pressure you encountered when you recomplete the well?

A. Yes, sir.

Q. Do you feel like the pressure that you've got listed here is going to be pretty much representative of what you might encounter in subsequent wells?

A. Yes, sir.

Q. Except for the Dakota you listed?

A. Yes.

Q. On all your curves where you've got the -- that we talked about, in the commingled situations is that -- That's not just two zones, that could be two or more zones commingled?

A. Yes, sir, that's correct.

Q. You're just relying on the EUR, on the initial rates?

A. Right.

Q. Okay. In a practical sense, what do you see as the potential for, say, commingled situations, like -- Do you see potential for three zones to be commingled?

A. Yes, sir, and just north of here, just north of the unit we have done that with the Mesaverde and the Gallup and the Dakota.

Q. Is that typically what you would do?

A. Yes, sir. At least two, but possibly three.

A. Okay. On your Dakota-Gallup well costs, is it my understanding that if you've got a -- say a Dakota-Gallup commingled completion, that that's going to cost you 364 times two?

A. Times two, on average, in the past, yes, sir.

Q. Have you got an estimate of maybe how many wellbores within this unit are going to be ultimately commingled? Any ideas?

A. Off the top of my head -- there's probably -- I can think of at least ten that we have dualed right now, that we would want to commingle. Some of those pressures might be a restriction, but ten now.

Future drills, we would commingle as many as we possibly could.

Q. Some of the duals that you have right now, are those uneconomic as duals?

A. Yes, sir.

Q. So you would want to switch over to commingles?

A. Yes, sir.

Q. What does that do to -- What does that reduce? Operating costs?

A. It reduces operating costs, because when you have a dual well, it's treated as two wells, and so you have an LOE charge that hits each well.

For instance, on the Dakota-Gallup operating expenses, that is the direct LOE charge, and so 540 a month per side for a dual well.

Also in the initial completion, if it's a new drill you have two strings of tubing and a production packer in a dual situation, whereas in a commingle situation you can run one string of tubing.

And also with one string of tubing in the hole usually you've improved your lifting efficiencies, and so you'll get more fluids out of the ground at a more efficient rate than you would otherwise.

And so all the way around it improves your economics.

Q. On the existing wells, though, all you're -- is it all you're reducing is the operating expense?

A. As a matter of fact, we feel like we're really hurting on the lifting liquid side, because the duals that we have, have inch-and-a-half tubing on each side and we have a lot of liquids, oil, and so we're not lifting that very efficiently.

We also have paraffin problems. We're not able to inject down the back side or along string. And so we have problems with that too.

Q. So by commingling, you could, in fact, increase production on those wells?

A. Yes, sir.

EXAMINER CATANACH: I have nothing further, Mr. Kellahin.

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

EXAMINER CATANACH: All right, there being nothing further in this case, Case 11,685 will be taken under advisement.

(Thereupon, these proceedings were concluded at 9:24 a.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11685, heard by me on January 23 1997.

David R. Catanach, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL January 24th, 1997.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998