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, LP, BP AMOCO AND ENERGEN RESOURCES CORPORATION FOR APPROVAL OF A PILOT PROJECT INCLUDING UNORTHODOX WELL LOCATIONS AND AN EXCEPTION FROM DIVISION RULE 104.D.3 FOR PURPOSES OF ESTABLISHING A PILOT PROGRAM IN THE PICTURED CLIFFS FORMATION TO DETERMINE PROPER WELL DENSITY REQUIREMENTS FOR PICTURED CLIFFS WELLS IN SAN JUAN, SANDOVAL AND RIO ARRIBA COUNTIES, NEW MEXICO

CASE NO. 12,857

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

May 2nd, 2002

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MICHAEL E. STOGNER, Hearing Examiner, on Thursday, May 2nd, 2002, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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May 2nd, 2002
Examiner Hearing
CASE NO. 12,857

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A P P E A R A N C E S

FOR THE DIVISION:

DAVID K. BROOKS
Attorney at Law
Energy, Minerals and Natural Resources Department
Assistant General Counsel
1220 South St. Francis Drive
Santa Fe, New Mexico 87505

FOR THE APPLICANT:

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

(Continued...)

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

FOR BP AMOCO:

HOLLAND & HART, L.L.P., and CAMPBELL & CARR
110 N. Guadalupe, Suite 1
P.O. Box 2208
Santa Fe, New Mexico 87504-2208
By: WILLIAM F. CARR

FOR XTO ENERGY, INC.:

JAMES G. BRUCE, Attorney at Law
324 McKenzie
Santa Fe, New Mexico 87501
P.O. Box 1056
Santa Fe, New Mexico 87504

* * *

ALSO PRESENT:

WILL JONES
Engineer
New Mexico Oil Conservation Division
1220 South Saint Francis Drive
Santa Fe, NM 87501

BILL HAWKINS
Petroleum Engineer
BP Amoco
1670 Broadway, Room 2456
Denver, CO 80201

* * *

WHEREUPON, the following proceedings were had at 8:23 a.m.:

EXAMINER STOGNER: This hearing will come to order. Please note today's date, May 2nd, 2002. This is for Docket Number 13-02.

And at this time I will call Case Number 12,857, which is the Application of Burlington Resources Oil and Gas Company, LP, BP Amoco and Energen Resources Corporation for approval of a pilot project including unorthodox well locations and an exception from Division Rule 104.D.3 for purposes of establishing a pilot program in the Pictured Cliffs formation to determine proper well density requirements for said Pictured Cliffs wells in San Juan, Sandoval and Rio Arriba Counties, New Mexico.

Call for appearances at this time.

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

EXAMINER STOGNER: Any other appearances?

MR. CARR: May it please the Examiner, William F. Carr with Holland and Hart, L.L.P., Santa Fe, New Mexico. We're entering our appearance on behalf of BP Amoco, and we will have a statement.

EXAMINER STOGNER: No witnesses?

MR. CARR: No witnesses.

EXAMINER STOGNER: Other appearances?

MR. BRUCE: Mr. Examiner, Jim Bruce of Santa Fe, representing XTO Energy, Inc. I have no witnesses.

EXAMINER STOGNER: Other appearances?

Can I have the three witnesses stand at this time to be sworn in?

(Thereupon, the witnesses were sworn.)

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER STOGNER: While they're getting set up, I will invite everybody that's interested to kind of shift around, because it appears that you're going to be shooting the screen and covering the material over here on the east wall; is that correct?

Let's go off the record for a while and let's get set up first. We're off the record at this time.

(Off the record)

EXAMINER STOGNER: Okay, let's go back on the record now.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner. We have a collective presentation on behalf of all three companies that are participating in the pilot project. The witnesses are going to be:

Mr. Mike Dawson. Mr. Dawson is a geologist with Burlington. He's going to give you a quick overview of what he anticipates to be the issues involved in the study. He is also a geologist, and he's going to set the background in the Pictured Cliff pools in the San Juan Basin to give you a sense of the geologic characteristics of the pool.

Mr. Eric Broacha is a petroleum engineer. He works for Burlington, and he is going to provide you the engineering basis for the project area.

And then Mr. Matt Gray is a landman with Burlington. He's going to illustrate for you the satisfactory compliance with the notice requirements, identify for you each of the plats that we have for the 24 pilot wells that are at standard locations. They will be increased density wells in a standard 160-acre spacing unit. There are an additional six wells that could not be located at standard locations, and we'll talk about those, and they're separately indexed in the exhibit book.

With that introduction, then, we'll have Mr. Dawson commence his presentation and discuss with you the framework of the study and the geology.

EXAMINER STOGNER: Okay now, I have Mike Dawson, Eric Broacha, and what was the third one again?

MR. KELLAHIN: Matt Gray.

EXAMINER STOGNER: Now, they all work for Burlington?

MR. KELLAHIN: They do.

EXAMINER STOGNER: All right, please continue.

MIKE DAWSON,

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

A. I'm Mike Dawson, I'm a petroleum geologist. I've worked for Burlington Resources and its predecessors for over 20 years.

Q. On prior occasions have you qualified as a petroleum geologist and testified before the Division?

A. Yes, sir, I have.

Q. What are your responsibilities concerning this pilot project area in the Pictured Cliff reservoirs in the San Juan Basin?

A. I've been instrumental in designing a test program and furnishing geologic support to our reservoir studies.

Q. And you are part of the technical team that's involved with the various companies to make a study of the opportunity for increasing the density in the Pictured Cliff pools in the Basin?

A. Yes, sir.

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

EXAMINER STOGNER: Any objections?

Mr. Dawson is so qualified.

Q. (By Mr. Kellahin) Mr. Dawson, we've put up the first display. If you'll turn into the hardbound exhibit binder and turn to Exhibit Tab 2, the first display after the indexed tab is the colored pool map that's on the display screen, Mr. Stogner.

In addition, if there's people in attendance that would like copies of the exhibit book, we do have them available on a CD disc that you can view and install through your computer. If you'll give me your name and address, we'll have Burlington provide you with the disc copy of the exhibit book.

EXAMINER STOGNER: Yes, Mike Stogner --

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: -- 1220 South St. Francis. Would you -- Do you all have those available today?

MR. KELLAHIN: Yes, we have some sets today, and we will hand those out to the extent we have them, and in addition you have the hard copy and the book.

EXAMINER STOGNER: I'd like to reserve one, but there's everybody else here that wants one, then I can get one later.

MR. KELLAHIN: There's no music.

EXAMINER STOGNER: Oh, well, in that case...

(Laughter)

EXAMINER STOGNER: This will be an interesting way for me to go back and review and utilize this. This is something new, and I appreciate that, so...

MR. KELLAHIN: We'll see if it works on a regular basis, certainly.

Q. (By Mr. Kellahin) All right, Mr. Dawson, describe for us what we're seeing on this first display that's identified as the Pictured Cliff Pool Map.

A. This map defines the 29 pools that we have identified as having Pictured Cliffs production. We've included it as sort of an introductory index map to show the distribution of the productive areas of the Basin.

From the 29 pools that we've identified, we believe that approximately 3.6 trillion cubic feet of gas have been produced from approximately 6220 wells. The Pictured Cliffs, of course, is nearly entirely a gas-productive formation. It's only produced a reported 784,000 barrels of oil, so it's essentially a dry gas reservoir.

Let's see, the discovery well, I think, is very interesting. It was the first commercial Pictured Cliffs production. It was completed in November of 1927. It was the Number 1 Frank Garland in the southeast of Section 34, 29 North, 11 West. That is in the Fulcher-Kutz Pool. That's Section 34, 29-11.

Of interest to me is the fact that the same quarter section has produced nearly continuously since 1927. It's now on its third wellbore, but that well is producing 80 MCF a day as a current rate. So I think this typifies the long-lived production that we see from the Pictured Cliffs reservoirs.

Q. Mr. Dawson, let me ask you the source of the map that is displayed here. How did you get the various pool configurations and boundaries?

A. Those came from the OCD Aztec office.

Q. Do you have a summary that shows us what in you opinion, or the collective opinion of the technical group, is the reasons that justify pursuing the opportunity to increase the density in the Pictured Cliff pools?

A. Yes, sir, in the next slide we'll list some of our key observations that lead us to ask the critical question, is increased density needed in the Pictured Cliffs? I'd like to just briefly summarize these observations and these lines of investigation. Each will be elucidated in a lot more detail later in the testimony.

One of the first things that lead us to ask this question are the results of a four-township pilot volumetric study. What we found was that we actually had a relatively low recovery factor from the Pictured Cliffs formation relative to other tight gas formations throughout the Rocky Mountain province.

A second observation that we've made that leads us to ask the critical question is that, looking at historic pressure data and some data that we've acquired in the last couple years, within the productive field areas of the Pictured Cliffs, we see highly variable pressures today.

Another thing that we've recognized is that we are fairly inefficient in completing the lower Pictured Cliffs, which tends to have very low matrix permeabilities. And that sort of leads us to want to investigate whether we're recovering all the gas that we can from that interval.

A fourth area of investigation involves wells that have produced concurrently from the Pictured Cliffs within 160-acre blocks, and historically we were able to find about 80-some-odd examples of that, and about 45 or so had clear enough data, including pressure and rate data, so that we could at least address the production trends and look for interference and so forth.

Then the final thing that we've looked at, that I think bears on the question of increased density, is our successful redrill and restimulation programs in the Pictured Cliffs. In particular, in the redrill program we go into areas where we've abandoned production, and we're able to drill a new well and have economic results.

So in summary, we've addressed each of these areas. None of the areas give us conclusive evidence that increased density is appropriate. Each leads us to want to further our investigations and gather more data.

Q. Do you have a slide, Mr. Dawson, that summarizes for us the major objectives of the pilot project?

A. Yes, sir, this next slide also poses a critical question that we ask ourselves: Why should we implement a pilot program? And it summarizes some of our data needs in order to thoroughly evaluate how appropriate infill drilling might be in the Pictured Cliffs formation.

One of the first things we find that we need is some new core, and we plan to core wells to be drilled with foam so that we can minimize the invasion of drilling fluids. We find the limited data that's available in our files and in our partners' files suspect in terms of water saturation in particular.

The other thing that's lacking is much analysis in the lower part of the Pictured Cliffs formation, which represents a very low-permeability reservoir.

A second thing that we feel we need to address is the efficiency of our drilling and completion techniques. When we look at the Pictured Cliffs, especially with the historical perspective, what we realize is that the reservoir doesn't really behave as it did 20, 30 or even 50 years ago. It's a much lower-pressured reservoir. Also, drilling and completion technologies have changed over the years.

So we want to examine drilling and completion techniques in the context of a comprehensive reservoir optimization program.

The same thing goes for compression. We know it's an important component of Pictured Cliffs production. We need to learn all we can about compression and its effects on the reservoir in order to adequately evaluate increased density.

We need to collect more data for reservoir simulation studies and modeling. The best data we can get would be empirical data resulting from the pilot completion and drilling program that we're proposing today.

Finally, we feel like where the rubber really meets the road is going to be where we do pilot projects and actually look for interference, look for efficiencies or inefficiencies, try to document whether or not we actually can increase ultimate production.

So each of these areas of investigation and data acquisition will be explained in a lot more detail during the course of our testimony.

Q. Mr. Dawson, do you have a slide that gives us the outline of the presentation book and the various chapters that --

A. Yes, sir.

Q. -- you and the other technical people are going to present this morning?

A. Yes, sir, we do. This next slide shows that we're starting out with a geologic overview.

We're going to present the results of our four-township volumetrics study in some detail.

We're going to discuss the historical performance and production trends of wells that are produced simultaneously from the Pictured Cliffs in 160-acre drill blocks. They're described here as 80-acre well pairs, and we'll use this term several times through the presentation.

We want to present to you our 2001 layer pressure test program and the results of that program.

We want to show some of the results of the redrill and restimulation program that Burlington, in particular, has been very active in, as have our partners.

We want to define our proposed pilot program.

And finally, we want to review current pool rules and setback regulations and discuss some of the regulatory considerations.

Q. All right, Mr. Dawson, let's turn to Exhibit Tab 3 and look at the first geologic summary, if you will.

A. What we want to accomplish with this geologic summary is to give you a feel for the degree to which the reservoir stratigraphy and geology is consistent through the productive field area and sort of set out the ability to evaluate whether our proposed program will be representative of the entire productive area of the Pictured Cliffs.

Q. From a geologic perspective, Mr. Dawson, are the various Pictured Cliff pools, some 29 pools in the area, is the geology sufficiently consistent that we can treat the Pictured Cliff under a common set of geologic conclusions?

A. Yes, sir, it is.

Q. Is it, in your opinion, necessary to have pilot wells within each and every one of the pools involved?

A. No, it isn't, but we have tried within the constraints of our leasehold and economics to put tests in as many pools as possible, between Burlington Resources, Energen and BP.

Q. Give us a summary of the geology, then, Mr.

Dawson.

A. Okay, we're going to start out looking at a PC cum map.

Q. How is this useful in understanding the geology?

A. For the Pictured Cliffs, the cumulative production map reflects the depositional system and the geologic trends perhaps even more clearly than a gross sandstone or a net sandstone map.

Certainly structure is not a very important part of the Pictured Cliffs story. The structural contours basically parallel the production trends that we see on this map.

The production trends shown in red here represent wells that have cum'd over a BCF in general. What you see are very long, linear trends of high permeability reflected in this map. This represents deposition in a wave-dominated deltaic system, and it represents the accumulation of cleaner, better-sorted sands in the upper shore face and in the beach parts of the system. Those high-permeability sands aren't present everywhere, and when we get between the high-capacity trends we still have thick gross sandstone, but we don't have the high permeability that results in production and cum totals over a BCF.

The Pictured Cliffs depositional system prograded from the southwest -- try to use the pointer here -- in this area. And the red, by the way, is the outcrop of the PC, commonly taken to be a reflection of the outline of the San Juan Basin. But it prograded from the southwest to the northeast. As the sea level dropped, in effect, relative to this local area, we filled the accommodation space, and this represented the last regression of the large epicontinental seaway that covered most of North America. So in our local area, this was the last gasp of marine deposition.

As this shoreline system prograded to the northeast, it deposited trends of very high permeability rock with the best reservoir potential, and it sort of marched along. And we happen to know through some recent USGS work how long it took for it to build through the San Juan Basin from this outcrop down south of Bisti up to the Colorado border area. It took about two million years.

So our Pictured Cliffs reservoir rock -- it's wet near the outcrop, of course, but it's about 75 million years old. And as we get up into the Colorado area, it's about 73 million years old. And just for fun, we tried to find an analog to that, and that rate of progradation turns out to be just about the same speed or the same rate that your hair grows. So that's how long it took for us to fill in this basinal area with Pictured Cliffs sandstone.

Q. Do you have a slide that gives us a crosssectional view of the Pictured Cliff so that we can have a visualization or a characterization of what this looks in a vertical --

A. Yes, sir, we do, and if we could back up one, I'll show you where this schematic cross-section is. It's located right here. And while we're on this index slide, this is the volumetric study area, the four-township area that we'll discuss in some detail later, and this is the location of a type log that we've included.

EXAMINER STOGNER: Okay, when you said the cross-section, it's marked on the exhibit as the cross-section, there's a line there --

THE WITNESS: Yes, sir.

EXAMINER STOGNER: -- going from the northeast to the southwest, and then you have your type log within that magenta box --

THE WITNESS: Yes, sir.

EXAMINER STOGNER: -- is that correct?

THE WITNESS: Yes, sir.

EXAMINER STOGNER: Okay.

Q. (By Mr. Kellahin) This is the cross-section, Mr. Dawson.

A. This cross-section is called a schematic cross-section. It's actually based on very detailed log correlations. But what we really wanted to show here is something that could conceptually set us up for an understanding of the Pictured Cliffs reservoir and the depositional mechanics and the reservoir stratigraphy.

This is about 12 miles from end to end. This is updip to the left, and this is downdip, both structurally and stratigraphically. When we look at the Pictured Cliffs, the dip section in particular, we see parasequences prograding out, marching out into the sea, as our clastic system builds out onto a very gently dipping shelf upon which the Lewis Sea muds were being deposited.

The exaggeration here vertically is about 125 to 1, so this looks like it's quite a steep shelf situation. But if you put it in sort of the true geometry, the dip of the shelf would be around a degree or less. So it's a very shallow, just barely dipping shelf, dipping seaward.

What we want to show here is the distribution of the high permeability sandstones, and this is approximately to scale and fits our cum map fairly well. What we see in the upper shore face environment and the beach environment are sandstones that today have, say, greater than one millidarcy of permeability. Each of the parasequences has preserved somewhere, in general, some of these facies that provide the best reservoirs.

What you'll notice, though, is that most of the sandstone here -- and we're showing this as maybe 80 to 90 feet of gross sandstone -- most of it shown as the pale yellow color here has much lower permeability, very much tighter. In general, it has higher water saturation. And when we talk about an upper and a lower Pictured Cliffs, commonly we're talking about the tight stuff at the bottom, in contrast to the permeable stuff at the top.

Q. Is there a way to generally characterize the range of permeability for a low-perm area and then the ranges for a high-perm area?

A. Yes, sir, there is. The permeabilities at reservoir conditions in the updip part of the field could be as high as 30 millidarcies.

As we go deeper into the Basin we have changes in clay type and more compaction and thermal alteration. That maximum permeability might be as low as a millidarcy.

As we look at the Pictured Cliffs vertically, we have permeabilities that might range from that maximum of 30 all the way down to thousandths of a millidarcy, and essentially even with core, the permeabilities are not measurable. Yet there is gas stored in that extremely tight matrix system.

Q. Do you have a type log that you can describe for us?

A. Yes, sir, the next exhibit, please.

We've included this exhibit to define what we mean when we refer to upper and lower Pictured Cliffs. This is a well in northwest 25, 27 North, 9 West. It is a Mesaverde well, but it twins one of our recent Pictured Cliffs redrills.

If you'll look at the log, looking at approximately 90 feet of PC section here, you'll see that the lower Pictured Cliffs essentially is about as clean in terms of the shaliness as determined by the gamma ray as the upper Pictured Cliffs. You'll see that the porosities are actually fairly similar. There's a little higher porosity in the upper Pictured Cliffs.

The big contrast that we see in typical logging suites is in resistivity. The lower Pictured Cliffs has much lower resistivity. This is one of the phenomena that we hope to define and learn more about from our core program. What we believe is going on here is that we have in the upper Pictured Cliffs slightly coarser grain size, better sorting, lower water saturations. And we believe in order to adequately create a petrophysical model, that we need to distinguish between upper and lower Basinwide and perhaps actually have different log parameters, such as A, m and n in the Archie equation for the upper and lower.

This well is of particular interest since it twins a redrill and -- that was part of our layer pressure program. We measured the pressure in the upper and the lower separately and found that the upper Pictured Cliffs had 342 pounds of remaining pressure, the lower about 406 pounds. I think this pressure stratification is significant.

This redrill was drilled 310 feet from the old abandoned Pictured Cliffs well. Original pressures in this area were something like 500 pounds.

Q. In summary, then, Mr. Dawson, do you have a slide that gives us the general Pictured Cliffs characteristics that you have investigated?

A. Yes, sir, the next slide. We have listed here some of the key characteristics that we feel should be considered in particular in evaluating our proposed pilot program. I won't go into each one of these in detail.

In general, the Pictured Cliffs reservoirs were deposited in the same system as it prograded to the northeast. Grain sizes are similar throughout the productive area.

There are some systematic changes that you see going from the updip edge of the production to the downdip edge to the northeast, and the most significant, if course, is the lower permeabilities. Those result from greater depth of burial, more compaction.

There's actually a systematic change in clay type so that as we get toward the axis of the Basin, as we approach it from the southwest, we see more illite-smectite. Nearly all these clays are orthogenic or secondary, they weren't deposited with the sand grains. And so the greater burial has led to more swelling clay and more core-bridging clay in the downdip parts, and that's a big part of the story why it gets tighter as we go downdip.

But we feel that we have -- with the program that we're presenting to you today, we've sampled both updip and downdip areas of the productive area of the San Juan Basin, and we've also attempted to try to pick areas that were on trend, such as the -- greater than the BCF trends that we saw on the cum map, and off-trend in areas where cum productions have been less.

Q. Have you satisfied yourself, Mr. Dawson, that the pilot project wells have been dispersed and located throughout the Basin in such a way that you can sample the typical characteristics of the pool?

A. Yes, sir, we did that to the best of our ability. Of course, that's dependent on our leasehold and what wellbores are available to us for recompletions and what areas are available to us for new drills.

MR. KELLAHIN: Mr. Stogner, that completes Mr. Dawson's presentation.

At this time we would move the introduction of the exhibit material behind Exhibit Tabs 2 and 3.

EXAMINER STOGNER: Any objections?

The information in the booklet behind Tabs 2 and 3, Exhibit Tab 2 and Exhibit Tab 3, will be admitted into evidence at this time.

Mr. Carr, any questions? I guess not.

Mr. Jim Bruce, any questions? I guess not.

EXAMINATION

BY EXAMINER STOGNER:

Q. You talk about some new coring to be done --

A. Yes, sir.

Q. -- is that correct?

How many cores are you talking about? Will this be through the whole Pictured Cliffs interval?

A. Yes, it will, two cores approximately 120 feet. We plan on taking four trips and recovering 30 feet of core each trip for two different wells.

What will be different about this core from what's been done in the past is that we're foam-drilling. We're doing that in order to preserve the water saturation to the best of our ability.

It turn out that the volumetrics in the petrophysical model is extremely sensitive to your assumptions on water saturation. And in the past the Pictured Cliffs, when we core it, it's almost always invaded by drilling fluid. And in particular, when we're looking at a situation where the pore pressures have already been depleted, we expect a very deep invasion whenever we mud-drill.

So what we hope to do is analyze this core, and it will be the whole section. And we'll get from the very top, upper shore face, hopefully, and beach sandstones, all the way down to the distal, deltaic very tight sandstones that interfinger with Lewis shale.

Q. Have you or will you be investigating any of the cores that have been taken in the past?

A. Yes, sir, we will. In fact, we have a couple of our older cores at Texas Tech University. As we speak, they're trying to do some work relating water saturations to log resistivity. We've reviewed all the core reports that we can get our hands on.

Most of the wells through history have been analyzed only -- the PC cores only for water saturation, porosity and permeability, and actually most of those cores are no longer available. They've ended up in -- unfortunately, in landfills somewhere. But we've reviewed all of that data to get as much as we can from it.

After that review, we realized that there's some missing components that we need in order to give us confidence in our petrophysical model.

Q. Is this work being done at Texas Tech or New

Mexico Tech?

A. It's Texas Tech.

Q. Texas Tech. Did those old cores come from a certain era?

A. Yeah, in general the 1950s and 1960s is when most of the coring took place. That was a time when the field was evolving. The Pictured Cliffs, historically, was developed just by extending along production, and when you got a low-rate well, why, you didn't go any further in that direction.

So in general, they found the high-permeability parts of the reservoir and they extended it along strike. And many of those extensional wells were cored.

Q. Now, your presentation today has pretty much been an overview of the Pictured Cliffs formation. Will you be -- What kind of geological parameters will you be looking at in the different pilot programs? A closer look at the -- what the results in the -- What exactly will you be looking for with the pilot project?

A. Well, I'll try to look at the performance of the infill wells in a stratigraphic context so that we can come up with a predictive model. Our suspicion is that in order to most efficiently manage the Pictured Cliffs reservoirs, we're going to need to be able to predict whether infills in a certain drill block are going to be economic, uneconomic, whether there's going to be interference, whether there's not going to be interference, whether or not -- that the stratigraphy is controlling the reservoir performance. We're going to try to determine the contribution of natural fracturing to Pictured Cliffs production.

In general, we'll try to use geology to help us with a predictive model for infill well performance. Basically, we'll take those empirical results from each of the pilot infills and put those in a geologic context.

Q. How about you as a geologist, in determining the completion of the new infill wells? What kind of parameters are you going to be using? Are you going to be picking and choosing certain perforated intervals, or are you going to do an overall kind of perforation, or --

A. Well, that's a great question. We're studying, first of all, the sensitivities to various completion and drilling fluids, and we'll be doing some more of that work with our new core.

We know that the Pictured Cliffs formation has a very high clay content, ranging from -- About as low as it ever gets is, say, five percent, and intervals that we still call pay can have up to 35 percent clay. Nearly all orthogenic. And we know that, particularly in the downdip areas where we have the mixed-layer illite-smectites and when we have some chloride, that the reservoir is going to be very sensitive to drilling and completion fluids. So we're going to do some of that testing.

In terms of how much of the interval to complete, we've already done some work with that. We've looked at -- after frac logs and a limited number of production logs, trying to determine what the contribution of the lower Pictured Cliffs is. We know in general that it is likely to have a little more pressure than the upper, high-permeability part. We're trying to figure out whether we can actually get much of a contribution from that and whether it actually pays off to put perforations in it, or, alternatively, whether you should just concentrate on the high-permeability part.

One interesting thing that we've learned is that -- through our layer-pressure-testing program, that the lower, very, very low-permeability part of the formation is being depleted in terms of pressure, at least in the tests that we've performed where we've taken redrills out in excess of 1000 feet from the old well, we do find that that lower rock has been depleted. It has as much as 30 or 40 percent more pressure than the upper, high-permeability part, but still we are managing to drain it over the course of the 40 or 50-odd years that we have in most of our established field areas.

Q. In referring now to the map -- call that the base map behind the Exhibit Tab Number 2, when I look at this, there's obviously a grouping of pools together sort of in -- we'll call that the center, going from the northwest down to the southeast, in the center of the San Juan Basin. And then as you work yourself back to the north and the east, you've got some pools that kind of stand out by themselves. And in between there I'm assuming that's an area of nonproduction. I'm sure that it's probably been tested, but geologically speaking, what happened in this interval?

A. Well, that's the part of the Basin where the clay type has become dominantly illite-smectite, and what we're doing in that part of the Basin, for instance in the 29-7 area, we're still doing some extensional drilling in the Pictured Cliffs there. What we're trying to find are the sweet spots. You can find sweet spots that result from two things.

One would be to find where we've built up a beach and foreshore and built up and preserved those reservoir facies. Those tend to occur in rather narrow trends. It might only be a mile wide. And as we go down into the Basin, if we can't find that trend it's unlikely that we'll establish commercial production. Although there still may be gas stored in the rocks, the matrix permeabilities are so terribly low that you have a hard time even recovering

100 million cubic feet of gas.

The second thing you could look for is, there are places where apparently dissolution of cements and where we had a -- more unstable feldspar grains in our sandstone, where that's been dissolved, so where we have anomalies in that secondary porosity, unexpectedly. And those aren't necessarily associated with the reservoir facies. Those are usually found by accident, just by finding good shows while drilling and so forth.

The variations that we considered in selecting our pilot tests, the systematic variations, are gradational as we go from the updip pools down into the Basin, in the downdip pools. And so the white areas, obviously, are areas where no one's been able to establish commercial rates.

But it has not yet been fully developed, so there still is an effort to extend PC production down into the Basin, and I would kind of categorize that as exploratory extensional drilling.

Q. Or recompletions of existing wells?

A. Yes, sir, absolutely.

Q. Now as you know, there's several pools, or many pools out there that include the Fruitland sand portion of the Pictured Cliffs and the Pictured Cliffs.

A. Yes.

Q. Are those going to be looked at in a different manner, or are any of those going to be cored, or how will those be handled?

A. We don't have -- The three companies involved in the effort we're describing today, in general we don't have large leaseholds in some of the peripheral pools where the Fruitland sands are more prolific and where essentially we commingle Pictured Cliffs and Fruitland.

What we hope to do in the next year or even two years is to at least take a look at those pools and the geology, perhaps, work a little bit with the active operators there and see whether or not it's reasonable to extend by analogy the conclusions that we reach from our test program to those pools.

In general, we don't have a lot of data in-house now, and we don't have much leasehold to work with.

EXAMINER STOGNER: Any other questions of this witness?

Thank you, you may be excused.

THE WITNESS: Thank you, sir.

EXAMINER STOGNER: Before we continue, just for those that are in here, we're going to essentially go through the docket, the remaining cases. And this will be the Burlington case, and then we're going to have the Devon Energy case, that's 12,778. This is a re-opened case of a matter heard by Dave Catanach, I believe, a couple weeks ago. And then I have a short presentation from David Arrington on 12,858.

And if anybody is here for the remaining two cases -- this is 12,862 and 12,758-A -- both of these are what we refer to as the inactive well hearings, and these are wells in -- a group up in Chaves County and another group in the Lea, Roosevelt and Chaves County, that portion of District 1. These will not be called -- these two inactive well cases won't be called until after lunch.

So I just wanted to make that announcement, so if there's anybody here in the audience that are just interested in those cases, feel free to take a long lunch break and show back up about one o'clock. You will be safe then to show back up. Due to some scheduling of our witnesses, the Division witnesses won't be available till then. So if we get through with these cases this morning, I'm going to take a break anyway until lunch.

So I just wanted to make that announcement. If there's anybody here for those two cases, the inactive well cases, feel free to take off and come back at one o'clock, and either we'll call those or you will see that we're still on the Burlington case or one of the other two cases.

Thank you, Mr. Kellahin, you may continue.

MR. KELLAHIN: Thank you, Mr. Examiner.

At this time we'd like to call our engineering expert, Eric Broacha, is the next witness.

ERIC BROACHA,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Will you please state your name and occupation?

A. My name is Eric Broacha. I am a petroleum engineer with Burlington Resources.

Q. Have you testified on prior occasions before the Division?

A. No, I have not.

Q. Summarize for us your education.

A. I have a bachelor of science degree in chemical engineering from Colorado School of Mines.

Q. In what year was that?

A. 1978.

Q. All right.

A. I have worked in the industry as a petroleum engineer for the last 23 years with both majors and independents. For the last 18 years my area of focus has been tight gas reservoirs in the Rocky Mountain region, all basins. My experience spans from petrophysics to reservoir modeling to general reservoir-engineering issues.

Q. What has been your involvement in the design of the Pictured Cliff pilot project?

A. I've been a member of a team for the last year. My contribution has mainly focused around the design of a new petrophysical model of a testing program with a new core, also the collection of data for reservoir simulation and the calculation of gas in place and volumetrics in the four-township area and across the Basin.

MR. KELLAHIN: Mr. Stogner, we tender Mr. Broacha as an expert witness.

EXAMINER STOGNER: No objection, Mr. Broacha is so qualified.

Q. (By Mr. Kellahin) Let's start with Exhibit Tab 4 and explain to Mr. Stogner the volumetric portion of the study.

A. Other slide, please. Other way.

The purpose of this study and what I'm going to show you here is, we need to understand what the -- at the current spacing, what our recovery factors were. We have picked, selected an area which I believe is representative of how the PC has produced across the Basin. We picked a four-township area, which includes 27 to 28 North, Range 9 West to 10 West. The study area included 559 PC wells.

The objective of the study area was to first calculate the gas in place in the Pictured Cliffs per 160-

acre-spaced area, calculate the main resource and then estimate what the recovery factor would be for a typical well on 160-acre spacing.

Two types of analysis method were used. We used volumetrics using the well logs to calculate gas in place, and we used the decline curves from each individual producing PC well to calculate the EUR of each well.

Q. Can you summarize for us the characteristics you've selected to define why you chose this four-township project area?

A. Yes, I can. This slide here illustrates the main selection criteria we used to select the four-township area. I'll show you on the map that proceeds this that the area we've selected encompasses a portion of five different PC pools. It also includes what we'll call on- and off-trend wells, or high-permeability wells and low-permeability PC wells.

The area is also in one of the highest cumulative production areas in the Basin, or an area at the highest level of depletion.

Also in the four-township study area, the large majority of the wells have been restimulated, which means that they are currently producing at their optimum productivity, which will also enable us to calculate EURs of optimally completed PC wells.

In the study area we have a large number of digitized logs, 163 wells. This is very important since we used these logs to calculate volumetrics. We have production data on all the wells in the area, and we have pressure data on approximately 50 percent of the wells in the area.

Q. All right, let's turn to the map and get ourselves oriented.

A. As you can see on this display here, the red square outlines the four-township area that we studied, and also you can see that it encompasses a portion of five different PC pools.

Q. If I was to take a four-township area to try to do conventional volumetrics on and wanted to select as a target an area of the Pictured Cliff that might give me my greatest opportunity to see how well I had done in recovering the maximum amount of gas on current spacing, where would I place the project?

A. We believe that the four-township area we select probably represents an area of the most efficient depletion under current operating conditions of the PC, mainly, because of the behavior of the current wells, that they've been recompleted or redrilled, that the line pressures are at the lowest possible right now with our system, and we're looking at PC wells that are producing out of both the high-permeability PC and the low-permeability PC.

Therefore, the recovery factors that we calculate for this area are probably the highest you'll see in the whole Basin right now.

Q. So if I take this project area, do the volumetrics, it will give me a sense of how well I am doing under current spacing --

A. That is correct.

Q. -- to recover the gas in place?

A. That is correct.

MR. KELLAHIN: Mr. Stogner, Mr. Broacha has a number of individual slides in the exhibit book that are layered, so you'll have available for your own investigation the cum production map, an EUR gas-in-place map, an estimated-recovery map, the remaining-reserve map. But you finally get down to a summary page after you look at the maps, and that's where I'd like him to focus his next part of the presentation.

Q. (By Mr. Kellahin) Let's go to the volumetric conclusions, after you do all the volumetric work in the four-township area.

A. Okay. As you can see by this slide, from our current petrophysical model we calculate a gas in place in this four-township study area of approximately 1.3 TCF. In doing the decline-curve analysis in all 559 wells, we have calculated an EUR from the existing wells in this area of approximately 500 BCF. By subtracting the two, you have a remaining resource of 789 BCF remaining in the PC.

If we go ahead and divide our EUR by our gas in place you come up with a recovery factor. The current recovery factor that we're predicting for this area is only 39 percent.

Q. If this is one of my best areas, how do I know how well I am doing when I compare this to what would be your forecast of ultimate recovery from a tight-sand PC reservoir?

A. Typical tight gas reservoirs in the Rocky Mountains that are very similar to this recovery factors range from 60 percent to 75 percent. So the significance of this recovery factor is to -- either our petrophysical model needs further refinement, or some type of additional recovery mechanism -- either a change in completion technique or additional well spacing -- will be needed to recover the rest of the PC gas.

Q. What will you achieve with the pilot well program that would allow you to more accurately define the engineering parameters that go into the volumetric calculation?

A. The pilot well program, as I'll illustrate later in this presentation, has several parts. In each of the parts the program focuses on a different issue that we have identified as a weakness in our current model. Mike has already talked to you about the new core, and I will explain to you what we're going to do with that and how that will refine our petrophysical model to improve our gas-in-place calculation.

We are also going to be looking at -- With the drilling of the pilot wells, we'll be able to actually monitor whether we have -- see interference and what kind of rates we can expect, and also be able to collect data so we can do reservoir simulation for future prediction of increased-density wells.

Q. When we look at your conclusions from the volumetric analysis, one of the things that you need to investigate further is the probability that current density within the volumetric area is inadequate to maximize your recovery?

A. That's correct.

Q. All right. In addition, you're going to examine the parameters such as water saturation and resistivity and other components of the calculation?

A. That is part of the petrophysical program that we have designed. Those are -- Some of the main weaknesses in our gas-in-place calculation right now is our inability to calculate current water saturation in the PC.

Q. Mr. Dawson made reference to the fact that historically in the Pictured Cliff there are occurrences where a 160-acre spacing unit has had two wells producing at the same time.

A. This is correct.

Q. Let's turn to Exhibit Tab 5 and talk about what you have identified as the 80-acre well pairs. Is there a display that shows where those wells are scattered?

A. Not in the presentation. We have a large map that does show the distribution of these wells across the Basin. Once we had finished the volumetric area analysis and realized that increased density may be an option, we did research and tried to find in the Basin where historically wells had produced simultaneously on an 80-acre-type spacing or two wells per 160.

Q. Before you start talking about this part of the chapter, let me identify what I've handed the Examiner. This is an additional display we will separately mark after the hearing. It shows, I believe the 49 well pairs. There were originally, I think, 80 investigated, and the map you now have doesn't have all 80. It shows what Mr. Broacha finally studied.

You have a distribution of those areas?

A. That's correct.

Q. Their location is not unique or confined to an individual well?

A. That's correct.

Q. Give us the time frame of where you discovered the occurrence of two wells within a 160 spacing unit.

A. Most of these well pairs produced between the mid-1970s and the early 1990s. We identified --

Q. Go ahead.

A. We identified approximately 85 pairs, although we only had sufficient information on approximately 49 where we could do any type of analysis. Most of the well pairs which I'll refer to as original and second well were approximately 1000 feet apart, so they -- kind of was analogous to a current infill situation.

Although we looked at all 49 pairs, production and pressure data turned out to be inconclusive from our analysis. But I will review some of the observations that we did see by looking at all 49 pairs.

The first observation that we noticed was approximately -- 40 to 50 percent of the well pairs appeared to exhibit some type of interference in later years, and I will give you an example of what we mean by interference after we finish the observations.

The second observation we noticed, if we looked at the total producing rate from the lease while the original well was producing and while both the original and the second well was producing, lease production increased during the period of time when two wells were producing off the lease, as compared to only the one.

The third observation was, if we did a decline-curve analysis on the original well, both while it was producing by itself and while it was producing with the second well, it appeared that in most of the cases we actually had an increase in reserves while the two wells were producing.

Now again, the analysis, we felt, was inconclusive because -- and I'll show you on this example -- much of the time when the two wells were producing was a time of gas curtailment in the Basin due to basically lack of sales with the marketing companies forcing the operators to choke back many of the wells.

Q. It wasn't a regulatory gas-allowable curtailment?

A. No, it was not, it was more an overabundance of gas in the marketplace at the time.

Next slide, please.

Here is an example of what I'll call one of our best or one of the wells we felt we can do the most analysis on. You'll notice there are two wells, the Kutz Government Number 8, which I'll refer to as the original well, and the second well, the Kutz Government Number 8J, the J designation, again, indicating infill.

The original well produced from October of 1953 until September of just last year, 2001. You can see it's a fairly good well, an on-trend well. Cum production is approximately 1.35 BCF.

The second well was located approximately 732 feet away from the original well. It produced from November of 1973 until April of 1992.

Next slide, please.

This is a semi-log plot of the production trends of both the original and the second well. The original well is in the blue here, the second well is in the red. As you can see from this plot, it's very difficult to see any type of interference between the two wells.

This plot is based on monthly production data, so what I did was, I converted the monthly production data to annual data -- next slide, please -- to try to understand if there was interference between the wells.

On this plot here, you can see production data on the Y axis and time on the X axis. The red dots there are the original well, and the blue squares are the second well, and the green curve right here represents total lease production.

You can see from this plot that when the second well came on line, the production did not change in the original well. Also notice that between the early 1980s right here and the early 1990s, this is the period I'll refer to as gas takes or curtailment when both wells were choked back.

Now, sometime at the early 1990s, 1992, the second well was converted to a coal well and no longer produced from the PC. At that same time the original well was worked over, and that's why you see the increase in production.

The importance of this plot is to notice that while both wells were producing, you don't see a decrease in the rate from the original well.

This is one of our best cases. The rest of them, as you can see, interpretation is very difficult.

One thing you will notice -- next slide, please -- if I draw a decline curve through the original production -- this is a green line represented right here -- I don't see any change in the decline except for the period of time when they worked over the well. In other words, I can't really see a direct effect of the second well producing simultaneously with the original.

Now, if I can draw this same decline curve on our original plot, which is a semi-log plot of production -- and again, you can see here, it appears flat and appears like you don't see any effect from the second well.

Now, this well pair also had pressure data on it.

So if we look at the next slide, we can observe the pressure data of both the original well and the second well. The blue diamonds here represents the pressure data collected on the original well, and the red circles represents the pressure data collected on the second well.

You can see the decline in the pink curve here. This is the decline of the original well. When the second well came on line the pressure was approximately 120 p.s.i. higher than the pressure in the original well. However, after about four years the pressure of the two wells became about the same. This does not necessarily indicate interference, but it indicates that the pressure around both producing wells came down to the same point.

Again, we can't really -- from this example here, I can't really tell you yes or no, whether the two wells are affecting each other.

Q. Do any of these pairs currently produce -- any of these spacing units with pairs currently produce both wells at the same time?

A. Currently? No, they do not.

Q. That practice is stopped, for whatever reason?

A. Early 1990s, all of the second wells were converted to some other formation for some reason. I do not know why.

Q. If we're trying to decide well density in the

Pictured Cliff, the strategy that you have investigated here is to see if we had ample data on wells that were on effective 80-acre density and whether that was enough evidence to show you that all of these pools needed to have that type of density?

A. That is correct. We were hoping by looking at these historical well pairs that it would answer our question about whether increased density was needed or not and which areas it was needed. As we went through the analysis, it became evident that because of curtailment and other issues, we did not have enough data to make that decision.

And that's one of the reasons for going forward with our recommendation for a pilot program, is to collect this data under more controlled conditions. Some of the other analysis that we saw, you did see interference with. But again, we can't really model that because there is insufficient data to be able to do that.

Q. Have you studied the pressures in the Pictured Cliff to see if there is sufficient pressure data from which you can use that database to draw definitive engineering conclusions about well density?

A. Yes, we did. We conducted in 2001 an extensive layer pressure measurement program, which we are continuing this year also.

Q. Let's talk about that. If you'll turn to Exhibit Tab 6, let's go through the pressure data.

A. This slide shows the synopsis or summary of what we did in 2001. We measured what I'll refer to as layer pressures in 16 different PC wells. Five of these wells were new drills and 11 were what we refer to as redrills.

The distance for the redrill case, the distance between the original well and the redrill well, ranged anywhere from only 10 feet to over 1000 feet. Shut-in times varied from five days to 13 days.

To obtain better data, we used downhole bombs and we also used plugs, downhole plugs, to minimize wellbore storage.

Next slide, please.

The results of the layer pressure measurement program are summarized in this slide.

Pressure measurements indicated we had some level of depletion in all wells that we did test. Original well pressures across the Basin ranged anywhere from 500 pounds in the shallow areas to 1250 pounds in the deeper PC areas.

You can see there that the upper, middle and lower PC, the pressure ranges that we got from a test, they ranged anywhere from extremely depleted at 61 pounds, all the way up to almost virgin pressure at 1195 pounds.

You also notice that there was a difference in pressure at each different interval within the PC. We saw higher pressures in the lower, tighter zones, and we saw more depletion in the upper zones. But the bottom line is, we saw depletion in all the zones, in every well that we did test.

I have a couple of examples here where I compared the pressures we measured today with the historical pressures to see if they were on trend with what we saw in the past. You've already seen that we did have some pressure data on older wells. I have three examples here at different distances between the original well and the redrill well to kind of show you what we saw with all the wells we looked at.

First example here is a well in the 27-5 unit, Well Number 92. Again, the blue diamonds are the historical pressure data, and the red represents the pressure measurements that we conducted in 2001. This well here is an off-trend well. It had only cum'd about .3 BCF. The redrill was drilled only ten feet away from the original well.

You can see from the decline in the red right here of the original pressure data, the original well stopped producing here in 1991. The green line represents where the pressures should be when we measured them in 2002. And as you can see, we measured pressures that are very close to where they should have been. Again, we would expect this, since the two wells are only ten feet apart.

Now, the second example here shows two wells that are almost 1000 feet apart. And again, the blue represents the historical pressure data, and again the red line is the decline. This well here is a fairly good well. It produced about .7 BCF from 1962 to 1985, and then again in 1985 it was shut in.

The green line represents the pressure level in that well when it was shut in. The red right here represents the pressures that we measured in the upper, middle and lower PC last year. And as you can see here, the pressures we measured almost 1000 feet away were about 200 to 300 pounds higher than what was in the original well, again indicating that we had some depletion out that far, but not very much. Again, this example, the wells are actually 965 feet apart, but this is not always the case.

The next example shows two wells that are also 923 feet apart. Again, the blue is the historical pressure data, the red is the pressures we measured last year. You can see that in this case, the pressures we measured last year fall right on the decline of the original, showing that in this situation where you're almost 1000 feet away, you do have pressure depletion.

So we saw with all 16 wells every case was different, no matter where you are in the Basin. There was no pattern, there was nothing to say that on-trend wells had a certain depletion and off-trend wells had a certain different depletion, or by pool. It was completely random.

Again, this type of behavior leads us to believe that in some areas we're going to have to either need some type of completion enhancement or increased density to be able to produce all the resource, and some areas we may not. But we have to define that.

So again, the results of the pressure program leads us to believe that we need a pilot program to collect more data.

Q. Let's talk about your conclusions for this chapter.

A. Okay. The main conclusions are, first, as I've stated, all the redrills measured indicate some sort of depletion, both in the upper PC and the lower PC. The measurements indicated the existence of more vertical perm than we ever believed was possible in the lower PC. As Mike explained to you, the matrix perm in the lower PC is very tight, yet we saw a depletion in every well in the lower, indicating some sort of fracture-enhancement production.

There appeared to be relationships between the pressure we measured in the redrill and the original well cumulative production. The -- Next. The distance between the original well and the redrill. The azimuth between the original well and the redrill gave us an indication, and the area of the Basin or reservoir quality. Again, these relationships were very -- were not specific, but we did see some minor trends.

Q. Can we improve our recovery efficiencies without an increased density program by simply restimulating or redrilling the existing Pictured Cliff wells? Is that going to satisfy your problem?

A. We looked at our historical redrill and restim programs and the results we saw, that it will probably not satisfy it everywhere in the Basin. And I can go over next the results of our analysis of both our redrill and restim program to show you what we found, again indicating the need to collect a little more data to better understand this.

Q. Let's turn to Exhibit Tab 7 and have you give us that presentation.

A. First, let's look at the results of our analysis of our historical restimulation programs. Between the period of 1995 and 2001, Burlington Resources restimulated approximately 374 PC wells. All the restims were very successful. And what we mean by that was, we saw an increase in production. Our average increase was approximately 160 MCF a day.

What made the analysis more difficult is, in many cases after the restimulation the well was put on compression. So it was very difficult for us to distinguish the increase due to the restimulation and the increased rate due to the compression by itself.

However, five or six years later now, we have seen that many of these wells have returned to their original decline. In other words, the restimulation hasn't maintained the production of the well. We don't completely understand why the restimulations work. That is part, again, of the pilot program. We feel that if we can improve our knowledge of why these work, we can further improve how we're restimulating the wells and maybe in some areas replace the need for an increased density well with a restimulation of the existing well if possible.

I have two examples to show you what I'm talking about out of those 374 wells. Here is what I'll call an on-trend well. It is in the Ballard area, Ballard Number 7, Township 26 North, Range 9 West. It is a very good well. It was originally put on production in 1954, and since then it has cum'd about -- almost 2 BCF.

It was restimulated in April of 1995. You can see here immediately production went from about 1500 MCF a month to over 9000 a month. And it immediately started to decline. Right now, the producing rate on this well has almost returned to its original decline from six years ago. This well was not put on compression, so we couldn't analyze the results.

Now, we compare this with what we'll call an off-trend well or a lower-perm well. This is in the Township 26 North, Range 8 area, it's the Luthy Number 2. It is an off-trend well. You can see that it was first completed in 1952, and when the recompletion was done on this well, or the restimulation in 1996, the well had only cum'd about .15 BCF.

As soon as we recompleted the well production increased, as you can see by the production curve here. And it has stayed flat ever since; it has not returned to its original decline.

So this is the two types of situation that we've looked at. Again, we're trying to understand exactly why the restimulation works, why it works better in some areas than others, and can we improve it? So it is part of the PC resource optimization program that we're looking at and does affect increased density. It is an alternative if it will work.

Q. Can the poor recovery efficiency out of the Pictured Cliff be explained in terms of the vintage of the original wellbore compared to our technology now? Can you solve your depletion dilemma by simply redrilling your Pictured Cliff wells, rather than adding density to your spacing units?

A. Not necessarily. We have looked at a redrill program that we have been doing for the last five years also. A lot of times we'll have mechanical problems with some of the PC wells, which will force us to redrill them, and I'll go over the results of that program. In many cases, the redrill program will emulate what we'd see with an 80-acre-spaced well, only you'd only have one well producing.

Between 1995 and 1999, we redrilled approximately 52 PC wells. The redrill was placed anywhere from 10 feet to over 1600 feet away from the original. Two observations could be made from the review of the data.

One, we have some weak relationship between rate and distance from the original well, and also we had a weak relationship between the rate in the redrill well and the azimuth from the original well.

I have a plot here that shows the results of actually 79 redrill wells that we looked at. And you can see there's a lot of scatter here, for two reasons. One, this plot shows both off-trend and on-trend wells, so high-perm and low-perm wells, and some of these wells are on compression and some are not on compression.

But the general trend you see here is, as you get further away from the original well your average rate, for the first year, at least, is what we looked at where the redrill actually increases. And it starts increasing quite significantly when you pass about 400 feet.

Again, there's a lot of scatter, but it gives you the general trend, what we would expect from a redrill.

Q. Let's turn your attention now to the summary of the pilot program itself. If you'll look at Exhibit Tab 8, let me have you explain that to us.

A. Okay, again this is probably -- this pilot program is set up a little different than maybe pilot programs you've seen in the past. What we're looking at here is more than just, do I need an increased density well? We are actually trying to collect the data so that we can optimize the production of the PC resource at the same time.

So one of our goals here, or the main goal, is to investigate the need for increased density to optimize recovery and develop guidelines that tell us where and when we would need such an increase.

Our strategy is to first evaluate historical production pressure, core data, which we have done already. The conclusion is, we'll need to acquire new core data, refine our petrophysical model and revise our current volumetrics in the Basin.

Next, please.

We are planning to complete a number of pilot wells, monitor and evaluate the production trends from these pilot wells, also investigate and refine our current drilling completion techniques. As Mike has told you, the conditions in the PC have changed, which has forced us to re-look at how we're drilling and completing wells.

We're also intending to perform pilot well simulation studies and then from those studies to ahead and try to predict what infill or increased density performance would look like.

Now, in this endeavor we have two partners. We are partnered with BP and Energen, and we're working this together, this project.

Next slide, please.

Q. Let's turn to the summary.

A. What I'm going to -- I'm not going to go through every program here, but the difference in color is, these are the separate programs that we have divided the pilot program into, so that each one focuses on a different area where we need additional data so we can evaluate how to optimize the PC resource.

The first four there, in the white lettering, indicate programs that are already underway and we're already studying. The programs in the yellow down here indicate programs that will be initiated as soon as the pilot program is initiated.

Q. Mr. Broacha, let me ask you to take a moment and give us the characteristics that you selected to identify what would qualify as a project pilot well.

A. I believe these are outlined on the -- Actually, before I do that, let me show you on the map where we've placed the pilot wells, and then what I'll do is, I'll go through the criteria of how we selected these.

This is a map you've seen before. Again, our study area, our four-township study area, is in the red. What you're seeing now on the screen is the proposed pilot program to be implemented by Burlington. We have divided it into three different well types.

The black dots here are the new drills that we intend to do in 2002, and there are four of them.

The red dots are the recomplete pilot wells we intend to do in 2002. There are six of them.

And then the blue dots there represent the recomplete pilot wells we intend to do in 2003, and there are an additional nine of them.

Now, also you'll see here the wells Energen is proposing. They are proposing to do their wells in 2003. They're mainly concentrated on pools where we have very little leasehold. They are intending to do four new-drill pilots and two recomplete pilots.

And then BP Amoco, they're intending to do six recompletion pilots, and they will all be done in 2002.

So from this distribution you can see that we have at least one test in each of the pools where we have acreage available to do the tests.

Now, the next slide will kind of outline the criteria we use to select the pilot wells. As I mentioned, we wanted to do at least one pilot test per pool if we could. We looked at the distance at the pilot well and the offsetting producing PC wells to try to get a distance that simulated 80-acre spacing, so we tried to have a minimum 900 feet, a maximum of 1600 feet if possible.

We also wanted to place a pilot well in an area where the offset PC wells were in good producing condition. In other words, they had either been restimulated or redrilled, so they were at their optimum producing condition, so if any type of interference was going to happen we would be able to see it.

We also picked pilot wells, both on trend and off trend, since those are the two types of reservoirs that we're going to have to look at how do we drain optimally.

Now, when we looked at recompletion pilot wells, rather than just drilling the new ones, we also had to consider the existing producing horizon.

We tried to pick ones where the existing producing horizon was making less than 50 MCF a day, where the condition of the wellbore, the cement and casing were in good condition, so we could recomplete to the PC, and where the current formation could be commingled with the PC. In other words, where the current formation was not producing large amounts of water that may make it difficult to produce the PC later on when the pilot program is over and we end up commingling both zones together.

So these are the main criteria we used to select our pilot wells.

The one other piece that's not here is, we tried to minimize the number of new drills so we'd minimize the amount of surface disturbance. So that's why you see a mix between new drills and recompletes in the PC.

MR. KELLAHIN: Mr. Stogner, this slide is not in the exhibit book. We'll -- after the hearing, I'll supply you a copy of that, but it did not get in the book you're looking at.

Q. (By Mr. Kellahin) When I look at the 30 pilot wells, you were able to satisfy this criteria on 24 of those wells and keep them at standard locations?

A. That's correct.

Q. There are six that are at unorthodox locations?

A. That's correct.

Q. Can you turn to the exhibit tab that shows under Exhibit Tab 10 and show us what has caused the unorthodox-location wells to be at unorthodox locations?

A. Mainly what -- the reason these wells were -- I'll call NSL wells are not -- unorthodox locations, we were trying to satisfy the rest of the criteria, mainly distance from existing producing wells.

For example, this one right here, the Canyon Largo 204E, we tried to place this well 1226 feet away from the closest offset producing PC well. Topography did not allow us to go in certain directions, therefore forcing us to go into an NSL-type location.

We tried to minimize these. Out of all our pilot programs we only ended up with six of these out of the 30 that we had.

Q. Out of six NSLs, have you compromised any of your criteria in terms of selecting why you're using that as a pilot well?

A. No, we did not. In fact, the need for the NSLs came about by trying to get a test in every pool and minimizing surface disturbance by not having to drill a brand-new well. We could get around the NSLs if we limited our testing only to certain pools where we have the available wellbores or we drilled a new well. So that was a compromise that we made with these six wells.

Q. And those answers are consistent for all six of these?

A. That is correct.

Q. Let's go back to your presentation on the program, and let's look at the next slide. There you are.

A. Okay, my next slide is to answer the question, what kind of rate can we expect from the -- I'll call it typical pilot or typical infill well during our pilot program?

What we did was, we looked back at the results of all the redrills that we'd done, which emulate what a pilot will perform at. This is the compilation of that data here in a typical type curve. We expect a typical pilot well to IP at about 165 MCF a day and to decline starting hyperbolically, to exponential decline, eventually to cum about .7 B's in about 44 years. That is what our prediction is at this time with the data we have available.

Now, we can also look at typical costs of PC wells. And what I've done here is looked at not only the costs of the pilot wells but what kind of costs and economics we would see for development wells if we went into a program.

As you can see here, on the new-drill pilot wells the economics were actually negative because we've got a lot of testing we put into the program.

The pilot well recompletes here are more positive.

If we went into increased density and we had a drill well, as you can see, the economics are here.

Our best economics would be to take an existing wellbore and recomplete it to the PC or do a commingle, let's say the Fruitland Coal and the PC together.

Just to give you an idea of how all the economics compare in these various cases.

You have two more slides in there which I'm not talking about, but those slides are the background data for that graph. They give you the decline-curve parameters and the costs that we use in the economics.

Q. Let's talk about the slide that gives us our target dates for the project.

A. Okay, this slide summarizes our time line that we're predicting for the pilot program in general.

The first item here is, Burlington plans to drill/recomplete ten 80-acre pilot tests by December of this year.

BP Amoco plans to recomplete five 80-acre pilot tests by December of this year also.

Burlington also plans to take two new cores, as we've talked about, and complete the routine analysis by

December. The advanced core analysis is anticipated to be completed by July of 2003.

Burlington also plans to recomplete nine additional 80-acre pilot tests by July of 2003, and then complete our petrophysical model revisions and Basin volumetrics by August of 2003.

Energen has anticipated to drill and complete their six pilot programs by December of 2003.

And then our model simulation work should all be finished by December of 2003 also.

So by the end of next year we should have a good idea of the impact of increased density and where it will be effective and where it would not be effective.

MR. KELLAHIN: Mr. Stogner, that concludes my examination of Mr. Broacha.

We move the introduction of the exhibits behind Exhibit Tabs 4 through 8.

EXAMINER STOGNER: Exhibits between 4 through 8 will be admitted into evidence at this time.

EXAMINATION

BY EXAMINER STOGNER:

Q. I'm going to refer to Tab Number 5, and you talked about the Kutz Government Number 8 and Number 8J.

A. Yes, sir.

Q. Where were those wells located?

A. Those are -- Oh, I don't have the -- The location should be on the graph there. I don't have a copy in front of me.

Oh, thank you very much, sir.

Those two wells were located in Section 21, Township 28, Range 10 West.

Q. And that's within your project area, the four-township area in which --

A. Yes.

Q. -- you identified earlier?

A. Yes, those two wells are.

Q. The completion method used on the 8 over the 8J, was there much difference, or was there a difference?

A. Yes, there was. From what we can tell, the 8 was an open-hole completion shot with nitro, and the 8J was a frac'd well. It was also open-hole.

Q. Now, in your initial introduction today, I believe you introduced yourself as a tight-formation specialist, or that's what you have been working on for the last several years?

A. That's -- 18 years, yeah, that's correct.

Q. And has that all been in the San Juan Basin?

A. No, it has also been in the Green River Basin, Wattenburg, Hugoton, Cotton Valley, Texas, most of the tight gas fields in the US.

Q. Okay, and when did you move down or come down to the San Juan Basin area?

A. I worked in San Juan for Amoco back in the early 1990s and then recently with Burlington.

Q. Are you familiar with the gas vuggy studies of the Pictured Cliffs formation done back in the 1960s?

A. No, I am not, that was -- We did similar tests up in Wyoming, but I was not familiar with that. My main concentration was Mesaverde and Dakota in the San Juan Basin.

Q. So the Pictured Cliffs is somewhat of a recent study for you, essentially?

A. My last assignment with Amoco was a petrophysical model on the Pictured Cliffs back in -- I believe it was 1991.

Q. Now, it's my understanding that some of these will not only be an infill well, but the old well will be restimulated. Is that your plan or -- on some of the wells?

A. If the old well has not been restimulated already, then our plans is to do it before we complete the infill well so that all offset wells are at their optimum producing capacity, that's correct.

Q. Did you find some sort of a criteria on these restimulated wells, what created that, or at least what kind of conditions were present in that well before those wells were restimulated? Did you see some sort of a pattern?

A. No, and that's kind of disconcerting to us. That's one of the things we want to investigate during the pilot program is, what conditions caused the original well or the restimulated well to decline so much, and then why did the restimulation work?

Many of the restimulated wells originally completed open hole with a frac or with nitro, yet they did have high cums, so they were effective. Now, some of the reasons that we have come up with but we haven't been able to prove yet is, at the lower pressures we may be seeing some condensate drop out around some of these wells, which causes a relative perm problem. When you refrac the well, you actually frac past that perm damage.

That is something that we will be investigating when we have the new core, because right now, you know, we've looked at it, and our original theory of fines migration, we have consulted with some of the core companies, and they do not believe that that is what's occurring right now with the type of clays that we do have.

Q. Now, of the wells -- or I should say the 160-acre tracts that are going to have infill pilots on them, has there been some sort of a pattern which you have chose --

the original wells, were they from the 1950s and some from the 1970s or different eras?

A. That was not a criteria, but by default that's what turned out. There's a good mixture. We were more concerned with distance and condition of the offset wells to make sure that it was going to be representative and then whether it was on or off trend. And it turned out that many of the wells are spread all through the development. Some are 1950s, 1960s, 1970s.

Q. Now, are any of these 160-acre tracts -- did they have an old well from the 1950s that was plugged and abandoned with a replacement well, if you will allow me that definition --

A. Uh-huh.

Q. -- where this one, the new drill, will essentially be a third well, not concurrent production but a third well on a tract?

A. Yes, several of those tracts, the original well was replaced by a redrill.

Q. Okay. So that will give you some additional --

A. Yes.

Q. -- information on that.

A. We tried to cover every situation that we could foresee.

Q. Now, referring to the map, and if I remember right from the previous witness, production started in 1927 up there just a little bit north and west of your area. Did the historical beginnings of the production stay within the Bloomfield area, within this area that you're planning to do most of the infill projects, this 28-10, 27-9 area?

A. I don't understand the question.

Q. Okay. The oldest production in the San Juan Basin, is it within the area of what you're looking at?

A. It started there, but actually you'll see that wells started popping up in a lot of different areas, and that's how the different pools started to be developed.

Q. Okay.

A. They didn't just concentrate on one area to start with.

Q. Okay, so it wasn't a --

A. It wasn't just a migration out from that one area, just sort of sporadically.

EXAMINER STOGNER: Any other questions of this witness?

MR. JONES: Yeah, I've got a couple. Thanks, Michael.

EXAMINATION

BY MR. JONES:

Q. Mr. Broacha, I didn't hear either one of you guys mention the imaging logs. Are you looking at -- Obviously fractures are a big part of this problem with the random production, so are you going to run some imaging logs?

A. We have historically run imaging logs with mixed success. We have not finalized our logging programs for these wells as yet, and we're still looking at maybe trying them once again and seeing if the evolution with tools will improve the results. But the fracturing, as I understand it, in the PC is more random than, let's say, in the Mesaverde, and you don't have as much success identifying where those fractures are with imaging logs. It's almost luck to be able to see them.

Q. What about fracturing in the lower PC? Is that more prevalent than the upper PC with the portioning upward sequence?

A. The production indicates that it has to be because of the level of depletion.

Q. Right.

A. The imaging logs show some, but you can't really map it, let's say, if you're trying to do a mapping of the fracturing. We're still investigating how to look at that and gather the data before we start the infill program, or the pilot program, I should say.

Q. Okay, do you do two fracs in the PC, a lower frac and an upper frac?

A. No, right now we've only done one frac in the PC.

We have done some experiments with two fracs in the PC.
Q. Do you have stress data that shows that it's confined to -- the fracture being confined to the PC?
A. Yes. In fact, one of the programs that's ongoing right now is a fracture diagnostic program. Even though the results aren't all in, preliminary results show that we are confined to the PC interval.
Q. Okay, so you have your closure pressures on your --
A. Correct.
Q. -- PC?
On your drilling, do you use a closed mud system in your drilling?
A. No, we do not.
Q. And there is no coal tubing drilling planned for this?
A. Not for these wells, no.
Q. And I guess the biggest question I've got is what you've brought from the greater Green to this reservoir as far as what you predict, such as, you know, Parachute field and the Piceance, Barrett or Williams is doing a lot of infill drilling. Do you predict the same results here?
A. The PC is a lot different than those formations that they're infilling right now. The problem we get into is, our clay content is much higher and our pressure is

much lower, and it gives unique completion problems in, one, trying to unload the wells, and also the pore-throat geometry. We tend to have very small pore throats, so by capillary forces you tend to trap completion fluids, and you don't have the reservoir pressure to clean them up.

And that's kind of the situation we believe we're seeing now as the reservoir is depleted. That's why we're investigating new ways of drilling and completing wells, even though when we do this we always get rate, we're still investigating, can we get more rate, can we get it better?

Pressure is what hurts us out here in the San Juan Basin, or the lack of it, I should say, compared to Green River.

Q. So you're still planning on setting casing through the PC and frac'ing the wells?

A. Well, actually in some of the wells, yes. In other wells we have actually intended on topsetting the PC, drilling open hole with a non-water fluid and seeing what kind of production we can get first without fracturing, with compression, and then with fracturing, to try to kind of get the components of what each of those operations does for the total rate of the well.

Q. Can you do air drilling in this Basin?

A. We can in some areas where we don't have water problems from the coals or from some of the upper zones, and it has been done too.

MR. JONES: Okay, thank you. That's all my questions.

EXAMINER STOGNER: Any other questions of this witness? You may be excused.

How long do you reckon your next witness will take?

MR. KELLAHIN: Oh, less than 30 minutes.

EXAMINER STOGNER: Let's go ahead and take a short five-minute break.

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

(The following proceedings had at 10:30 a.m.)

EXAMINER STOGNER: This hearing will come to order.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Stogner. Our next witness is Mr. Matt Gray.

MATT GRAY,

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

A. Matt Gray. I'm a landman for Burlington

Resources.

Q. On prior occasions have you testified as an expert petroleum landman before the Division?

A. Yes, I have.

Q. What has been your responsibility for the Pictured Cliff project?

A. I've been responsible for identifying all of the owners offset to any of our projects, as well as coordinating with BP and Energen landmen to identify owners offset to their projects.

Q. In addition, are you familiar with the location and spacing-unit requirements for the Pictured Cliff pools?

A. Yes, I am.

MR. KELLAHIN: I tender Mr. Gray as an expert witness.

EXAMINER STOGNER: Mr. Gray is so qualified.

Q. (By Mr. Kellahin) Let's turn to the Exhibit Tab 11, and behind this tab are a number of individual displays. Let's take the first one as an illustration, and the first one I have is the San Juan 32-9 Unit Well 98J.

A. Uh-huh.

Q. All right. For this exhibit set, what have you prepared?

A. I prepared a map that will identify each individual pilot well, along with the parent well for that infill well, and I've also identified the distance between the pilot well and the parent well.

Q. Now, under a different exhibit tab we have set aside the six plats that relate to the six unorthodox well locations?

A. Yes, we have.

Q. Within the current population of 24 plats that we're looking at, in terms of notification to affected interest owners that are adjacent to the spacing unit containing the pilot well, or the proposed pilot well, what have you done about notification?

A. On these wells we notified all offset operators to the spacing unit. In the cases where the party drilling the well was the operator of the offset, we went to the working interest owner level. In cases where there was no PC well drilled, so therefore no operator, we identified the working interest owners in that formation and notified them.

Q. All right.

A. And there were no instances where the minerals were unleased.

Q. So for example, in each of these instances, if we take 160 acres where the pilot well is to be located, if the immediately adjacent 160 is operated by Burlington, you notify the working interest owners?

A. Yes, we do.
Q. And if the adjacent operator is Energen or BP Amoco, you also notify the working interest owners?
A. Yes.
Q. Okay. When we come to the population of wells under the tab for unorthodox well locations -- it's Tab 10 --
A. Uh-huh.
Q. -- if you'll turn to that first display, there's a Gallegos Canyon Unit Well 204E In this example it shows that the offset ownership is Burlington. In this case would you have notified the working interest owners?
A. Actually, this is an instance where BP Amoco is the operator of this well, and Burlington just happens to be the offset owner of the interest.
Q. Oh, and so you have 100 percent --
A. Yes.
Q. -- of the offset?
A. Yes.
Q. Is that true of all the rest of the NSL's?
A. No, it's not. There's actually just -- The only one that different is the Congress Number 18, in which we did have offset ownership that did not have a PC well already drilled in it, and in that case I went to the working interest owner level and notified those working

interest owners.

Q. As part of the notification, did you send these parties a copy of the Application and a notice of the hearing today?

A. Yes, I did.

Q. As a result, are you aware of any objection to the Application?

A. None that I'm aware of.

Q. If we go behind Exhibit Tab Number 1, which contains the Application, what have you enclosed for the Examiner behind that Application?

A. We had the Application, which is the letter of notice to all the owners, and behind that we have enclosed a list of all the owners that we notified, along with return receipts from any certified mailings that we sent out.

Q. And to the best of your knowledge, you have complied with the notice requirements of the Division?

A. To the best of my knowledge, yes.

Q. Let's turn now to Exhibit Tab Number 9 and show Mr. Stogner some illustrations concerning the current requirements.

A. Okay. The first map is just another map of the Pictured Cliffs. We can skip over that.

Q. This is our base source map that Burlington has prepared?

A. Yes, it is, and that's just in there to identify the Pictured Cliffs pools and to notify you that we did receive all those pool outlines from the Aztec OCD office.

Q. All right, let's turn to the next slide. If we're looking at all 20-something, 29 PC pools in the pilot project area, have you found any of those PC pools that have special rules and regulations?

A. None that we've been able to come by. That's not to say that there's some that we couldn't just find.

Q. The best of your knowledge --

A. To the best of my knowledge --

Q. -- the current search, they were all subject to Rule 104 in terms of well locations and well density?

A. That's correct.

Q. If we're going to illustrate to the Examiner the current location requirements under Rule 104, is that we can see on this display?

A. Yes, this display shows that the PC is developed on 160-acre drillblocks. The current setback distance, as you're aware, is 660 from the exterior of the spacing unit.

And one interesting point is that with these setbacks on 160-acre drillblocks, that only leaves 25 percent of the drillblock area available for drilling. And as Eric and Mike have alluded to, this could possibly lead to a negative influence on drainage of the drillblock, as we've seen in previous slides that the farther away you get from an existing well, the better it seems to be at this point. And we plan on studying that further in our pilot projects.

Q. Well, if the technical people determine there's a need for an additional well in the PC on an existing 160-acre spacing unit, that technical group is also going to have to deal with the well-location requirements of the rule?

A. Correct.

Q. All right. Are there some other illustrations that you can give us to identify the location problem?

A. Yes, this next slide shows the difference between the Pictured Cliffs formation and the Mesavede formation. And as Eric demonstrated earlier in our economics, the most economic way to develop these 80-acre Pictured Cliffs wells will be to commingle or to recomplete an existing well, which means that -- in order to get in a proper location for an existing well makes it very difficult, in that the setback issues are different in the two separate formations.

As you can see in the Pictured Cliffs, like I said, the area ratio that you have to drill in is 25 percent, while in the Mesaverde and Dakota the area ratio is 37 percent because you have that interior setback to the quarter section.

Q. All right, let me ask you this. Let's assume that we have a Mesaverde spacing unit in the east half of the section as you've illustrated here, you've got a 320.

A. Uh-huh.

Q. We've got a Mesaverde infill well that we want to exercise the opportunity to also produce the Pictured Cliff. It's likely that the Pictured Cliff is going to be at an unorthodox location unless we consider well distance requirements --

A. Correct.

Q. -- or the setback requirements in addition to density?

A. Correct, and that can be demonstrated in our pilot project. We spent numerous hours looking at hundreds of different situations to try to find these pilot projects, and in the instances where we were going to commingle these wells in order to find a standard location for the Pictured Cliffs it was very difficult. And as you've seen, we had six that we had to pick that were nonstandard, so...

Q. Do you find a situation where the ownership of the oil and gas in the Pictured Cliff is different between the two quarter sections in, say, a Mesaverde 320 spacing unit?

A. Yes, the majority of the time the ownership between the two Pictured Cliffs drillblocks is going to be different than the Mesaverde because of the allocation of the 160-acre spacing compared to the 320-acre spacing.

Q. So we can't solve our location problem by having common ownership in the 160 acres towards which you're making the encroachment?

A. Typically that's not the case, we cannot.

Q. Okay. Let's look at your last illustration, Mr. Gray. What are you showing us here?

A. This is just an illustration to kind of show some of the limitations that we're up against in trying to find infill wells.

Q. We are looking at a full section?

A. We're looking at a full section, and each one of these quarter sections, the green dots represent a current well drilled in that quarter section.

What this shows is that the setbacks -- with the 660-foot setbacks in the 160-acre spacing, the original well was oftentimes drilled just directly in the center of that 160-acre spacing unit. And that was done for various reasons: topography -- Infill was never even thought of when most of these wells were drilled, so there was never any concern as to where they put those wells.

And as you can see from our demonstration here, in order to have a standard location for our infill well, if a well happened to be in the very center of the drillblock the maximum distance you can get away with a standard location is 933 feet.

Q. So one of the things the technical group is going to study is to determine what may be a minimum distance between the infill well and the parent well?

A. Correct.

Q. And whether or not we need to examine altering setback requirements for the PC?

A. Yes, that's correct.

Q. In addition to well density, then, the well locations is a topic for investigation by the pilot project?

A. That is correct.

MR. KELLAHIN: That concludes my examination of Mr. Gray, Mr. Stogner. We move the introduction of his exhibits that he's talked about. I think they're Exhibits 9, 10, 11 and 1.

EXAMINER STOGNER: Exhibits 9, 10, 11 and 1 will be admitted into evidence at this time.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Gray, let me make sure I'm getting this straight. Behind Tab Number 9 -- this is the last page --

A. Uh-huh.

Q. -- you're considering the minimum distance of 933 -- 933 feet as the minimum from wellbores --

A. That was --

Q. -- or just the infill wells?

A. Well, this was just an illustration. In looking for these pilot projects, one of the main things, as I previously told you, we look for distance away from initial wells, from the initial well in the drillblock.

In doing that, we noticed that a number of the wells that we looked at were drilled directly in the center of the drillblock, which makes it very difficult to get very far away from that initial well. And in the cases of a recompletion it makes it impossible in a lot of cases to use the same wellbore and be on a standard location.

And this illustration is just to show you that if a well is drilled directly in the center of a drillblock, the maximum that you can get away from that well and be in a standard location is 933 feet. That's not to say that that's the maximum or minimum that we are looking to drill infill wells from the parent well, that's just to show you what kind of limitations we're up against in this situation.

Q. What kind of responses did you get from your notification, other than the people that are here today?

A. We have not heard anything, really, from anybody, as far as I know. I believe some people have supported it just verbally, but no letters of support. But I have not heard anything negative about our Application.

EXAMINER STOGNER: Any further questions of this witness?

MR. KELLAHIN: No, sir.

EXAMINATION

BY MR. JONES:

Q. Mr. Gray, can I ask you one question?

A. Yes.

Q. On the information-sharing for this project it looked like there was only one scenario where you will have a negative present worth index for -- I think that was for the drilling and complete new well on the infill wells. So the information-sharing, is it going to be just between Energen and Burlington and --

A. -- BP.

Q. -- BP?

A. Yes, that's the people who are participating in the project and who will contribute information to the pilot?

MR. JONES: Okay, thanks.

EXAMINER STOGNER: Any other questions?

MR. KELLAHIN: That concludes our presentation, Mr. Stogner.

EXAMINER STOGNER: All right, you may be excused.

Anything further, Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Would you provide me a rough draft?

MR. KELLAHIN: I'll be happy to.

EXAMINER STOGNER: And I'm assuming that for the presentation today there will be some sort of a revisitation paragraph included. What is the plan on that? 2003 of December or --

MR. KELLAHIN: Well, that's the conclusion, I think, of the simulation-study portion. It's December, is completion of the simulation work, and we're going to have to have some time to talk to the operators in the pool, not only about the results but what to do with those results in terms of density of well location. So I would think in the spring of the following year.

EXAMINER STOGNER: Okay.

MR. KELLAHIN: So I'll put some kind of reporting requirement in the draft order for you to consider, advising the Commission on the status of the pilot.

EXAMINER STOGNER: Okay, would appreciate that.

MR. KELLAHIN: One last thing, I would like to mark that large display which was not otherwise identified. We'll mark that as Exhibit, I guess, 12 to the hearing.

In addition, if you find it necessary, Mr. Examiner, I have larger copies of some of the other displays which are already in the book, but there are larger copies available if you need them.

EXAMINER STOGNER: I don't believe that will be necessary at this time. However, we'll know how to get ahold of you if that be the instance. And I do have a copy of the CD-ROM you've provided me. I appreciate that.

And if you'll get a rough draft to me --

MR. KELLAHIN: I think Mr. Carr indicated he had a statement he wanted to make.

EXAMINER STOGNER: Oh, yes, Mr. Carr? Statements at this time?

MR. CARR: Mr. Hawkins is going to make a statement for BP.

EXAMINER STOGNER: Why don't you come up here since we've got some noise, and that way it will at least be recorded more clearly.

Identify yourself and your affiliation, and please feel free to comment.

MR. HAWKINS: Okay, my name is Bill Hawkins. I am a petroleum engineer for BP.

BP is an Applicant in this case with Burlington and Energen, and we are participating in the PC pilot program with five infill wells. We hope to learn more about the potential for incremental recovery with these wells, and from the work that's been done by Burlington we see there is a significant potential for 80-acre infill development in the PC and the San Juan Basin.

One important issue which will need to be addressed in the future is how best to locate these wells, the 80-acre infill wells, to maximize recovery of gas. We believe this will most likely require modification of the current well-location setbacks, and we look forward to working with other operators and the NMOCD to address that important issue.

And that concludes our statement.

EXAMINER STOGNER: Thank you, any others?

Okay. With that, I'll take this matter under advisement and anticipate a rough draft from you, Mr. Kellahin.

MR. KELLAHIN: All right, sir. Thank you.

(Thereupon, these proceedings were concluded at 10:48 a.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 12857 heard by me on 2 May 2002.

________, 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 May 6th, 2002.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002