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 PARALLEL PETROLEUM CORPORATION FOR THE ADOPTION OF SPECIAL RULES AND REGULATIONS FOR THE WALNUT CREEK-WOLFCAMP GAS POOL, CHAVES COUNTY, NEW MEXICO

CASE NO. 13,986

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REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: WILLIAM V. JONES, Jr., Technical Examiner
DAVID K. BROOKS, Jr., Legal Examiner

September 20th, 2007

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, WILLIAM V. JONES, Jr., Technical Examiner, DAVID K. BROOKS, Jr., Legal Examiner, on Thursday, September 20th, 2007, 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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September 20th, 2007
Examiner Hearing
CASE NO. 13,986

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EXHIBIT

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A P P E A R A N C E S

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By: W. THOMAS KELLAHIN

* * *

WHEREUPON, the following proceedings were had at 8:38 a.m.:

EXAMINER JONES: Okay, let's call Case 13,986, which is the Application of Parallel Petroleum Corporation for the adoption of special rules and regulations for the Walnut Creek-Wolfcamp Gas Pool, Chaves County, New Mexico.

Call for appearances.

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

EXAMINER JONES: Any other appearances?

Will the witnesses please stand to be sworn?

(Thereupon, the witnesses were sworn.)

MR. KELLAHIN: Mr. Examiner, we'll try not to scare you with all this stuff. The initial impression is, there's a lot of information here and it's overwhelming for a short hearing.

The concept was to give you the opportunity to have a full and complete review of the Wolfcamp exploration that's going on in New Mexico with Parallel and others, in which the practice has become to drill two horizontal wellbores in the same 320-acre spacing unit. That is occurring in the southern end of this play, in an area called the Cottonwood Creek Pool. And it's being done through an administrative process for EOG. Every time they want to drill the second well, they are filing an administrative application that the Division must process in order to have that approved.

What Parallel has done on my recommendation is, north of this in an area that's been identified by the District as a new pool called Walnut Creek, the Walnut Creek Pool is our attempt to adopt special rules for that area in which you're allowed by rule to have the second well.

The presentation we're about to make to you has been upgraded from the one that Mr. Brooks and Mr. Ezeanyim saw in February of this year, which was a detailed presentation by PowerPoint setting up the science of this and the methodology in which the operators have chosen to develop this in the way they've chosen.

For your purposes, we will try to key you on the points of information necessary for you to enter an order and make a decision about the specific subject of this. In doing so, we'll try to briefly hit the highlights of how this study was evolved, the pieces of the puzzle, and in doing so at least give you the chance to ask questions, and if not now, to have the DVD program of the slide show -- the exhibit book tracks by page number the slides that you're about to see on the screen. The larger documentations are big copies of what on the screen turn out to be very small cross-sections or structure maps, which are impossible to use on a regular basis.

So that is sort of the scope of our effort today.

In addition, with your permission, we'll do something a little unusual. The first witness is our engineering witness, and Mr. Durham is going to make the introduction. And with your permission, I'd like to temporarily excuse him and call Mr. Moylette, the geologist, let him give us the summary of the geology, and then we'll recall Mr. Durham to give you the engineering science upon which he has made conclusions based upon the prior geologic presentation. And at the end of that process we hope we've answered your question.

In addition, I have available to you Mr. Mike Gray, who's the petroleum landman for this company. He and I have both made a diligent search, and pursuant to the Division Rules with regards to special pool rules you're going to find that the only operator within this pool as currently designated -- or within a mile the only operator is Parallel. So under the current rule we do not have any other parties to notify. However, we chose to notify all the interest owners of current production in these wellbores, and so that was done.

Finally, as a further footnote, the Division has recently approved for the south half of Section 16 two wells, the Swale 1 and the Swale 2, and it has done that administratively with the assistance of Mr. Brooks and Mr. Ezeanyim, and we do now have that approved.

So our efforts now are to get a generalized rule for the pool that we can use for the further development of this concept for accessing production in the Wolfcamp that we might not otherwise obtain.

EXAMINER JONES: Okay, thank you.

EXAMINER BROOKS: The chief engineer will be very pleased with your --

MR. KELLAHIN: We expect his gratitude.

EXAMINER BROOKS: Go ahead.

DEANE DURHAM,

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. Durham, sir, please state your name and occupation.

A. My name is Deane Durham. I'm the engineer for Parallel Petroleum Corporation.

Q. Where do you reside, sir?

A. Midland, Texas.

Q. On prior occasions have you testified before the

Division as a petroleum engineer?

A. No.

Q. Summarize for the Examiner when and where you obtained your degree.

A. University of Texas, 1987.

Q. What has been your involvement on behalf of your company with this horizontal drilling program?

A. They've made -- the New Mexico engineer. I'm in charge of the complete well operations from staking through construction, drilling, completion and production.

Q. Were you present here in the Division hearing room back in February of this year when an informal presentation was made to the Division technical staff concerning this topic?

A. I was.

Q. Have you been involved with Parallel's horizontal wellbores being drilled and permitted in this area?

A. Yes.

Q. Are you knowledgeable about the wellbores being drilled and permitted by EOG and other operators?

A. Yes.

Q. Have you worked in association with a qualified petroleum geologist to study the geology?

A. Yes, we have.

Q. And based upon all this effort, do you now have conclusions and opinions about what the Division should do in managing this production?

A. Yes, sir.

MR. KELLAHIN: We tender Mr. Durham as an expert petroleum engineer.

EXAMINER JONES: How do you spell your last name?

THE WITNESS: D-u-r-h-a-m.

EXAMINER JONES: Okay, Mr. Durham, you're qualified as an expert in petroleum engineering.

Q. (By Mr. Kellahin) Please proceed.

A. Gentlemen, this is a rather lengthy PowerPoint presentation, and you have the presentation in its entirety in your booklet. The live demonstration itself could go on as long as an hour and a quarter, and we'll try to shorten that by moving through some slides that are apparent, and then I won't bore us all by reading every point given.

I'm sorry, may I stand up?

Q. Yes, sir.

A. The evidence you'll be given today will support the necessity for 160-acre density for horizontal drilling in the Wolfcamp formation, and feel like not only for this pool, named the Walnut Creek, but it will also support, I believe, in the entire 300,000 acres of the Wolfcamp horizontal gas play as we go forward.

So what we'll present today, the Wolfcamp formation of southeast New Mexico is productive, and it's very similar across the whole 300,000 acres. This play is economic -- it's not economic using old conventional vertical drilling methods and completion methods.

Not just this pool, but the entire play can be economically produced using horizontal drilling and multi-stage slickwater-type fracture techniques.

The data you'll be seeing today is in four major categories. There is a transient pressure analysis that was actually seen here on February 13th. I'll run through that quickly, because it has been presented here before, it is public data.

There's a one-page analysis that confirms the permeability and porosity of that transient pressure analysis, and then there's a recommendation for a fracture half-length in order to produce on a 160-acre density.

The next area is microseismic studies. There is one in this presentation. There's an additional one on your CD that we'll not present here, but it -- both of them support the fact that the way Parallel fractures their wells actually is less than the 1100-foot recommended fracture half-length.

And then there's production data on four wells in a section that supports the recovery factor for four wells per section or a density of 160 acres pre well. And then finally there'll be some engineering calculations, volumetric calculations that also support this 160-acre density.

And when it's all through, said and done, we'll show that using two horizontal drain holes per 320-acre production unit should be utilized to take -- produce this natural resource. And if we only limit ourselves to one well per 320, there's a potential for revenues of approximately 1 1/2 trillion cubic feet of gas to be lost to the public and the producers and the mineral owners of the state.

That was their introduction.

We'll go through a quick history, and then Mike will get up and talk about the geology.

Then as I mentioned, the transient analysis, the microseismic data and production data, and then we'll summarize. Try to go pretty fast so we won't bore anybody.

In the late '70s this Wolfcamp formation was drilled by a number of producers and a great number of wells. There were 19 vertical producers over that 50-mile fairway, and the very best one recovered approximately three-quarters of a BCF over about 28 years.

Parallel's participation started in 2004 with a company called Perenco. We drilled six horizontal wells as a working interest owner with those guys. The wells were drilled and they were completed in what we felt was a substandard method, Parallel's opinion.

We participated in 2005, with EOG completing the Nile 22 Number 1, and it was the first well in the play to be properly stimulated in our opinion. It has cemented liner, multi-stage slickwater frac, selected perforations along the horizontal, and as a result it came in at slightly under 4 million per day, initial rate.

To date the industry has permitted over 300 wells and completed well over 66. This slide was made in February.

And then active producers in the play are ourselves; Parallel Petroleum; EOG Resources; LCX Energy, formerly Perenco; David Arrington; Yates; COG; Devon and MYCO.

Picture on your left is just a cartoon rendering of the field. The purple there contains the area we're -- of this pool, the Walnut Creek pool. Directly south of that purple area in yellow is where the Cottonwood Creek Pool is.

This is a simple drawing showing the escalation in activity over the last three or four years and why we're involved in the play. It's a technology-driven play. You need horizontal drilling, multi-stage fractures to actually produce this tight gas formation.

Fairway is rather large, 50 miles long by 10 miles wide, encompasses over 300,000 acres. And as we'll show later in our volumetric calculations, that adds up to about 3 trillion cubic feet of gas recoverable.

Parallel currently owns about 103,000 gross acres and about a third of the play, makes us one of the larger players in there. And there is acreage remaining, but a limited amount of acreage remaining in this play.

All of our acreage was acquired specifically for the Wolfcamp. We didn't have acreage that was Morrow play or whatever and then -- we acquired all our leases for the Wolfcamp, we're targeting that zone.

And Parallel also has a unique and, as I see it, intelligent position, because we participate in over 75 percent of the wells drilled out here with our drilling our own wells, participating with EOG, LCX, MYCO and others. I feel like we have a pretty good handle on the best practices involved in the field.

We're now at the point where -- the geology section --

MR. KELLAHIN: With your permission, Mr. Examiner, we'd like to temporarily excuse Mr. Durham and call the geologist.

EXAMINER JONES: Sure.

MR. KELLAHIN: Thank you.

MIKE MOYLETT,

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. Moylett, sir, would you please state your name and occupation?

A. I'm Mike Moylett, I'm a petroleum geologist with Parallel Petroleum in Midland, Texas.

Q. Mr. Moylett, have you testified on prior occasions before the Division?

A. Yes, I have.

Q. What has been your involvement with the geology in this project and in this presentation?

A. Basically since day one I've been the geologist on this New Mexico play.

Q. Are the following geologic exhibits exhibits that you have either prepared directly or that you have verified are accurate and correct to the best of your knowledge?

A. Yes, they are.

Q. Let's turn to the geologic presentation. Are the exhibits that we're about to show information that you have reviewed and for which you have opinions?

A. Oh, yes, I have.

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

EXAMINER JONES: Mr. Moylett is qualified as an expert petroleum geologist.

Q. (By Mr. Kellahin) If you'll turn to the next slide, we're now on page 6 of the exhibit book.

A. This basically is just a paleogeography map of the Permian Basin of west Texas, southeast New Mexico. It's just to orientate us where we were during Wolfcamp time here.

We are located in the carbonate shelf on the northwest shelf here. This is Eddy County, Chaves County, swings over here.

The play as we have identified it runs from basically southern Chaves County through northwest Eddy County to western Chaves County, so that's where we have identified the fairway for gas production. However, the -- the zone itself you can correlate even further, but the productive one that's -- in our opinion, is located where I've pointed out.

This is just a stratigraphic chart of the northwest shelf showing where we're located here. The Wolfcamp zone is our target. It's Permian age, it produces from the Wolfcamp, basically, it's a gas reservoir, this stratigraphic chart.

This next cross-section is a diagrammatic cross-section depicting how I interpret the Wolfcamp to have been deposited. It was deposited in a lagoonal environment, basically a sabkha shelf model. The Wolfcamp reservoir was deposited in a restricted lagoonal platform facies belt where dolomitization and porosity has occurred to enhance -- dolomitization and fracturing has occurred to enhance the porosity and permeability of the reservoir, but in deep enough water where evaporites are not prevalent to occlude the porosity.

The reservoir itself as particted [*sic*] here is in this brownish color here. Now updip from the reservoir to the north northwest we do have evaporites that cement the porosity that form the updip seal to the Wolfcamp.

Downdip from the Wolfcamp reservoir are basinal limestones that do not contain a reservoir development.

So this is a stratigraphic trap that has anhydrites updip and basal limestones downdip, so it's a stratigraphic trap.

Next one. This is a type log of a well south of Hope. It's our Music Box well. All the logs I'm going to show you here are neutron density logs. This is the gamma-ray scale here, neutron scale in blue, and a density log porosity in red there.

I've identified here that -- what we consider the top of the Wolfcamp pay zone, the base of the Wolfcamp pay zone. Down below that you get your basinal lime muds. This Wolfcamp shale you can correlate throughout the entire region. I've used the Wolfcamp shale as a structure map marker to map. You can follow it around.

MR. KELLAHIN: Mr. Examiner, if you'll turn to the additional handouts, there's a larger copy of this type log that's easier to read for your study.

THE WITNESS: Right.

Q. (By Mr. Kellahin) When we look at the type log, Mr. Moylett, the horizontal wells are drilled horizontally in what portion of the pay interval of the Wolfcamp?

A. Within the top and the base of the Wolfcamp pay. We usually try to stay in the better porosity zones, because it increases your rate of penetration.

Q. What is the strategy for doing that?

A. The strategy? As far as drilling it?

Q. No, to staying in that portion of the pay interval?

A. Well, basically we know the dips of the reservoir, I'll explain next, but we know what the dips are, and basically it's about one degree a mile. So we just, you know, pick a target point in a vertical well, project it out into the toe of the lateral well.

We also want to point on this cross-section, Wolfcamp pay zone consists of alternating cycles. It's very shallow, carbonate, depositional environment. The matrix porosity, you could see here where the porosity actually increases to the left. That's a dolomitic fusulinic packstone. It contains your matrix porosity.

Now -- and in a lagoonal environment over time you start getting shallow water, you get more restriction, and you get conditions not favorable for the fusulinids to live, so either the facies belts move to a different part of the lagoon that's conducive for their growth, or they die out.

And on top of your dolomite you get a burrowed lime mud, and that usually has some fractures in it. And on top of your burrowed lime mud you get another flooding event, deepening of the environment, and you get a thin lagoonal shale on top of that lime mud. And then as that shale column water starts thinning, you start getting your conditions favorable for the dolomite again. So -- And we have verified this through core, we have a bunch of cores out here.

So basically you've got a dolomite, a burrow lime mud, lagoonal shale. And these things -- once again, there's -- in a carbonate environment there's a lot of lateral heterogeneity and also vertical heterogeneity. These things do not correlate over 50 miles, but the -- The overall packages do, but, you know, any kind of carbonate environment, you know, these things are -- have a lot of heterogeneity in them. Otherwise, one well could probably drain a whole field, you know, one continuous --

Q. Mr. Moylett --

A. -- pay zone.

Q. -- what is the reason to have horizontal wells as opposed to vertical wells? What are you achieving?

A. Well, with vertical wells it's just not economic. What we need to do with the horizontal well is increase the KH to the wellbore, just open up more of the reservoir.

And there's also -- there's natural fractures in the reservoir that we're seeing through cores, through FMI data, and also through some of the fracs we've monitored. Your principal stress out here -- you know, your maximum stress direction is north-south. So that means your fractures would be running north-south.

If you look at the play history, operators originally drilling their wells north-south. Then as we start doing a little more science and a little more engineering till we realize we have to be drilling east-west to encounter more of the fractures. So you look at all of the industry -- right now we're pretty much drilling them east-west. Every now and then someone might drill a north-south well based on a land consideration, not a technical consideration out there.

Q. Do you have the locator map that shows these wells? Should be the next exhibit.

A. Yes. And like I say, the overall thickness of the reservoir is anywhere from -- gross thickness, you know, anywhere from a few feet up to 70 feet thick.

This is a locator map. It's actually what I use to identify the fairway. The well I showed you was down here in the southern part of the map here, that type log.

This, once again -- this is Eddy County, here's Chaves County. These are how I identify the fairway. What I use -- this is -- these lines here, what I consider the Wolfcamp porosity limits, and in here are some of the key wells I use to identify the fairway.

The data I use to identify the fairway, obviously if I had vertical production, those are some key wells. Also, I need to have density porosity over zero percent in the mudlog show. If I got density porosity over zero percent I'll have a mudlog show. So I use that to define -- define the fairway here.

And once again, I defined the fairway first, and then we started leasing. We didn't actually start leasing and then define the fairway.

MR. KELLAHIN: Mr. Examiner, there's a larger copy of this display in the handouts.

THE WITNESS: And some of the key wells -- this is a well -- this is a 19 South, 23 East, Section 7. It's the Mesa Frank State well, it's made .4 of a BCF to date. The Yates State AEX Number 1, almost .8 of a BCF. And the Yates Terry well, about .4 of a BCF.

But it takes 30 years to get that cum. These wells really have a really, really -- really sharp decline, and within a month they're down to 40, 50 MCF a day. This well maybe hung in there with about 100 MCF. And I say "M", you know, a thousand cubic feet of gas per day. But really just...

And they were really targeted for the Wolfcamp. They were either, you know, deeper Pennsylvanian producers, the Morrow or Atoka or a Strawn well, and then they would -- on the way out of the hole, if there was pipe in the ground, they'll perf it.

So once again, if I had density porosity over zero percent, I always have a mudlog show.

And also, a lot of the old wells out here, when I got into the top of the zone, back in the '50s they actually run a DST in the top of the zones. They never completed them, but they actually had a little show, and so something -- something to target.

So that's just a map showing the key.

For scale here -- this is a large map -- each one of these boxes is a square mile, or roughly 640 acres. So you can see we identified the play. It's almost 60 miles long and about 10 to 12 miles wide.

Q. (By Mr. Kellahin) Let's turn to the structure map.

A. Okay, this is a structure map on top of the Wolfcamp shale. You have a large version of it on your -- in your handouts there.

The contour interval on this is one inch to 100 feet. There's really no structure on this map. You have the Huapache anticline down here to the southwest. That's a tertiary Laramide feature. It wasn't present during Wolfcamp deposition. The Wolfcamp probably does -- actually does extend over the Laramide, but basically cut off right here.

There's really no structure out here to -- actually to say it's a structural play. You don't see any closures. Mainly just a regional dip. It's roughly 100 feet a section, about -- and downdip is to the east here. So about one degree -- one degrees downdip, so...

Measured depth down here, you're looking around 4200 feet to the top of the Wolfcamp pay zone, around 5500 feet up there.

So that's just a structure map to show you. For reference here again, here's the Chaves County-Eddy County line.

Color-coded here, Parallel wells are -- horizontal wells are blue, the EOG wells are in green. If there's a gas symbol on there, it's a producer when you look at your map, because a lot of the permitted wells are also on this map. Structure map.

Next I made a gross isopach map for the play, and that's from that type log, the top of the Wolfcamp gas zone to the base of the Wolfcamp gas zone. And for the most part, the thickest part of the fairway, you get about 70 feet of gross pay in there, and generally if you've got more gross pay you've got more net pay.

However, there's not a correlation sometimes between a really good thick well and a good producer, versus a thin well and a good producer, because of the natural fractures in the reservoir.

EXAMINER JONES: Oh.

THE WITNESS: However, your best chances are, sometimes, to stay in the thick. It just makes sense. But there are some good wells that are associated with thins and some poor wells associated with thicks. So that's just a -- that's a gross isopach map. Contour interval is 10 feet, so basically here's your zeroes, and up in the thick here, up to 70 feet thick.

This next one is just a placeholder. Well, you have the -- Next one is cross-section A-A'. That cross-section runs basically south to Hope -- or call it beyond Hope, but it's really -- truly south of Hope, New Mexico, all the way up to basically Hagerman up in there. The town of Artesia is just over here.

It shows you on that cross-section -- it's roughly almost 60 miles long of used -- the pilot hole logs, the Parallel logs, EOG logs, and it shows that you can correlate that zone -- the gross interval, over the -- basically the whole trend. The Wolfcamp shale doesn't change. You see the cross-section here. You can follow that throughout the play.

Basically it shows -- It's really one continuous reservoir, with some heterogeneity in it, but basically you can correlate it throughout the play. So even though you've got a different name of the pool here, a different pool here, a different pool here, a different pool here, it's the same pool.

And it shows you -- actually, you can correlate it over vast distances up in there, so that --

MR. KELLAHIN: Mr. Examiner, as Mr. Moylett indicated, it is --

THE WITNESS: Right.

MR. KELLAHIN: -- the actual map itself is in the handouts.

Q. (By Mr. Kellahin) And then the next one?

A. And one of the -- one of the wells on the cross-section that we'll talk to a bunch is EOG Nile well. That was one of the first wells -- that was actually the first well in February of '05 that actually was completed with a cemented liner, you know, four-stage frac, you know, Barnett shale-type frac.

But basically, I -- This is basically neutron density logs running throughout the fairway. Don't really run resistivity logs. It's a dry-gas formation, you know, you really don't have any water out here, so -- you know, at first we put a little more science to it, but now I just basically have a mud log and a porosity log, you know, to pick our target zone.

The next map is actually a -- it's a structure map, it's actually -- not actually a -- we're going over the regional part, you know, of the fair- -- I'm just focusing up on the county line area here. These two rows of EOG wells in our row -- in our Walnut Creek field, just showing you that -- I just had a blowup of the structure map, and it's just a larger scale to show you where -- you know, where our pool is and where their pool is.

And also that map has more data in it, you know, because that's been -- a lot of the -- more of the activity has been recently done up here. It's actually updated that map. The structure map and isopach map was probably done in February of '07, as far as having a presentation --

Q. Let's take a moment, Mr. Moylett, and unfold --

A. Right.

Q. -- one of these copies for the Examiner so he can actually see all the data you have on this map.

A. Right.

EXAMINER JONES: Which one is that?

MR. KELLAHIN: This is identified on page 13 of the exhibit book as item number VIII.

THE WITNESS: This -- basically the scale, this map is one inch to 3000 feet, 100-foot contour interval. It just shows you that, you know, even when you get into a more, you know, heavily drilled area the structure doesn't really change that much either, you know, so that's -- that's the point.

Anything with a gas symbol with a line going across the horizontal -- horizontal producer. The wells that don't have any gas symbols are just permitted wells.

And you'll see up in 16 of 15 South, 25 East, the Forego Number 1, the Swale Number 1, All Along and the Silver Charm -- that's our Walnut Creek pool.

You come down to the county line and those green wells and even the red above it, that's the Cottonwood Creek Pool. And you see what EOG has done on the density of their wells, they've basically drilled theirs at 160-

acre spacing, which is -- geology and the engineering will support, is prudent practice, because these wells are $2.2 to $2 million. You know, we could just drill two wells per section versus four, we'd be saving almost $4.5 million a section. So we -- we wouldn't want to do that.

So anyway, that's just kind of a large-scale of the area, just kind of hone in on it. You know, you see the town of Hagerman up there, Lake Arthur.

The next map is just a blowup of the isopach map that we saw up in Chaves County, and it's pretty much -- Again, 10-foot contour intervals, you've got gross isopach map --

EXAMINER JONES: Which exhibit is it? Just the -- it says top of Wolfcamp; is that what it is?

THE WITNESS: Wolfcamp isopach map, yeah --

EXAMINER JONES: Oh, Wolfcamp --

THE WITNESS: 13-VII.

EXAMINER JONES: Here's the gross.

THE WITNESS: It's the next one, 13-VIII.

EXAMINER JONES: The gross isopach?

THE WITNESS: Yes, yes. Appearance the same as the regional map, it's just -- And if you see, most of the activity has stayed within the fairway as identified by porosity limits. Those wells up in 13-27 in the northwest part of the map are not economic, so --

EXAMINER JONES: Okay, they're not --

THE WITNESS: -- we feel pretty good about the fairway for the most part --

EXAMINER JONES: Okay.

THE WITNESS: -- because like any geology map, it could change a little bit, but -- I drew the fairway first and then started with these things, but...

The point being, the thick part -- you see, we're focusing in the thick part of the play right now, and over time it will start being developed towards the edges, depending on the results of the wells. But there's natural fractures in the play.

Q. (By Mr. Kellahin) Before you fold up all your maps, would you show the Examiner the focal point of the various study area? There is the --

A. Right.

Q. -- Alysheba area?

A. Okay, we first started drilling up in here, the Alysheba area. That's where actually we monitored a couple fracs up in here. We also monitored some fracs south of Hope.

But here's the Alysheba. Here's the Walnut Creek pool right up in here, in 15-25. That's where -- that's where Walnut Creek field is.

Then south of it, right on the county line, is the -- in 16-15-25 is where Walnut Creek field is.

EXAMINER BROOKS: 16 or 15?

THE WITNESS: 15-25, excuse me, Section 16.

MR. KELLAHIN: Mr. Examiner, the Division's District Office is currently showing all of 16 and the south half of 17 as being the boundaries of what they have created as the Walnut Creek Pool, and they've assigned a pool number to it. I don't know if it's actually been on your nomenclature docket.

EXAMINER JONES: I don't know. I know there's a Walnut Creek Pool already.

THE WITNESS: Right. The 4 goes in that, and --

EXAMINER JONES: It's real small.

THE WITNESS: Yes. Hopefully it's going to get bigger.

EXAMINER JONES: Okay.

MR. KELLAHIN: We're ready to make a transition back to the engineering data.

THE WITNESS: I got one more cross-section --

MR. KELLAHIN: Okay.

THE WITNESS: -- and you can look at it, but it's just a blowup of the -- we'll go back -- it just shows -- in the Walnut Creek Pool -- it's just -- since I showed you our blowup of the structure map and the isopach map, I show you some large-scale logs, I just go from the Swale Number

1 to the Forego Number 1 to the Alysheba, and it shows the same thing as the regional -- big regional cross-section, that you can correlate -- it's the next one. I think it's in the bottom of the pile there.

EXAMINER JONES: This is not it?

THE WITNESS: It's the next one way at the bottom.

This is just a three-well cross-section, goes from the Swale to the Forego to the Alysheba, and it shows -- yes, you can correlate the Wolfcamp shale, you can correlate the top and base of the Wolfcamp zone, but there is some lateral and vertical heterogeneity in the reservoir.

And also, the point being, you know, you've got the Swale -- and that's a neutron density log, five-inch log. One inch is 40 feet on it. The scale between wells, actually numbers on top. The Swale and Forego are --

EXAMINER JONES: Okay.

THE WITNESS: -- about .9 of a mile, that's -- what, roughly --

EXAMINER JONES: Seven --

THE WITNESS: -- seven miles over to the Alysheba.

You can see -- you can follow the Wolfcamp shale across, you can follow the top of the pay zone and base of the pay zone, but there's porosity changes within, you know, those wells up in there.

And once again, it shows, you know, the Swale and Forego, you know, probably should be in the same pool as the Alysheba or vice-versa. It's -- the pools -- it's the same reservoir throughout the -- throughout the area.

That's the point I wanted to make, just kind of wrap it up unless you have any questions. But basically you can correlate this from basically, you know, south of Hope all the way up to Hagerman. It's a tight, tight, you know, gas play.

EXAMINER JONES: Spectral gamma-ray on this?

THE WITNESS: Yes, that's what you see, a spectral gamma-ray on there, then a gamma-ray --

EXAMINER JONES: You needed all the spectral? You need the spectral gamma-ray?

THE WITNESS: You know, those -- I don't really see any hot streaks in there for the most part, you know, I still -- every once in a while the dolomites look a little streaky.

But for the most part those high-porosity zones, all your lagoonal shales, you can see on a spectral gamma-ray on there, and you'll see it on a regular gamma-ray. But those really high-porosity zones are your lagoonal shales.

DEANE DURHAM (Recalled),

the witness herein, having been previously duly sworn upon his oath, testified as follows:

DIRECT TESTIMONY

MR. DURHAM: This next section is the transient pressure analysis presented here on February 13th. It's a matter of public record, and I have permission of the author to use this.

As we've seen it before, we're going to try to go through it fairly quickly. But it's a study of transient pressure analysis of the -- of eight key vertical wells, because they have enough time to actually have some transient pressure. And so we'll just go forward.

We're going to do a quick reservoir description, very quick because Mike has already explained it, results of the analysis and then drainage and the spacing recommendations.

This was the entire play encircling permitted wells at the time.

As Mike mentioned, it's a dolomite with an anhydrite inclusion and thin limestone interbeds. It also has some very thin shale interbeds in there, typically 20, 30 foot of measurable permeability and an additional 50 feet, sometimes, of nano- and micropermeability surrounding that.

So they took eight vertical wells in the Hope area and the Cottonwood Creek area and they determined permeability, the effective infinite fractured half-length, and the area that is drained.

The best well in the Hope area, using this study, was drilled in '79, had a net height of 31 feet at 4400 foot depth and 9-percent porosity, which is relatively good for this field. IP'd a little less than a half a million cubic feet a day and cum'd a little over an eighth of a BCF and took it 27 years to cum that.

The EUR for this well is .63 BCF. So you do a little quick calculation, it's going to take another 60, 70 years, at least, to achieve that. So hence the vertical wells aren't really economic in today's dollars.

The permeability gathered from this was a .023 millidarcy, and it drained 49 acres. And there's the well log, it's similar to the logs you have in front of you.

And then if you plot dimensionless pressure versus dimensionless time, this type curve also indicates and supports the low permeability, .02 millidarcies, and the effective drained half-length of 122 feet.

And just fading in here, this cartoon represents that effective fracture drainage area -- that's the drawing of the drained portion of the fracture. In red is the actual fracture that has proppant in it. And then the blue is the maximum fractured half-length achieved.

So as you can see, the actually produced area in yellow is quite a bit smaller than the fracture you have created.

This is the next example well. In the log there, very low permeability, .006 millidarcies, only drained 29 acres. That's a '80 model well, very low production.

And then here's a vertical well in the Cottonwood Creek area. It's a '79 vintage well. Basically same properties, 21 feet of net pay at a depth of 5000 feet, and very good porosity for the zone, 14.5 percent. Permeability is still .02 millidarcies or below. Effective drained fractured half-length 69 feet. It only drained 21 areas [*sic*], and it's taken a long time to do that.

This is a log, a vertical well log, of the -- of a horizontal example. It's the EOG Yellow A-7 Number 1. It was drilled east-west at about 5000 foot TVD. The IP of that well is 1.2 million, completed in '06. And the 180-day cum on that well was 135 million cubic feet, so in 180 days that well cum'd almost as much as a vertical well did in 27 years.

EXAMINER JONES: I'm sorry, this was the log of the horizontal portion or the log of the --

THE WITNESS: No, what we do is, we drill a vertical well, pilot hole, and log the vertical well, and then we target the actual zone, we plug back and drill horizontally into that target zone.

EXAMINER JONES: Okay.

THE WITNESS: So all the logs you're looking at are logged during vertical well operations.

And so what's the summary?

Most of the permeabilities are .01 millidarcy, .02, very low permeabilities. Very low drainage area in vertical wells, 20 to 40 acres. And it takes a very long time to drain that, upwards of 30 years.

So what is the recommendations for the fractured half-length?

It's okay to overlap fractured half-length in wells, it's okay to overlap even the propped half-length slightly. It's not okay to overlap the effective drained half-length, or your wells would interfere with each other during production. So we're looking at achieving the greatest effective fractured half-length possible without stretching it out there and interfering with the well.

So what's our goal in horizontal drilling to achieve that?

If you drill four transverse wells on a section, we want to frac 1100 feet normal to the wellbore in order to achieve 500 to 600 feet of prop length, in order to achieve that effective length of 300 to 400 feet.

And a section would look like this. At the end of radial flow the orange indicates the drained pattern of four wells. That's not to scale, of course, it's just a cartoon, but that's what your section would look like, the yellow being undrained portions of that section.

And this is a 20-well sample of production, 90-day production. The wells in our field, this Walnut Creek field, the three wells we currently have, fall in or below the P_{50} number, the median well, so we're talking about average wells here, not anything less or more.

Conclusions of the study again.

Low drainage areas, long time to drain, very low permeability. It is a tight gas play, and we can only utilize it economically using the new technology such as horizontal drilling and multi-stage completion techniques, and by four-well density per section.

Excuse me a sec.

And this is just a core analysis we did. We were partnered with Bold Energy in a well called the Delilah. They did a core analysis. We had a separate core analysis done on that core ourselves. And this core analysis -- and it's easier to read on your sheet, but the best sample, number 3, has a .0104-millidarcy permeability in air and at 3.5-percent porosity. So it just supports the analysis that it is low porosity, low permeability.

And then we have a microseismic -- I think this is the last time I have to get up.

As Mike said, we did microseismic studies on two -- we've done them on three or four wells now. There's two included in your CD, there's only one in this presentation. This is the Alysheba well, which you have the log on the cross-section.

And I'll just mention, the other one on the CD, it's rather lengthy because it goes through a -- I'll call it microseismic 101. It lays out a bunch of the groundwork how we do microseismic, and this one was a later well so they didn't include all that in our presentation.

It's the Alysheba Number 1. We monitor the Alysheba frac, which is going west to east from another horizontal well called the Bold Venture, and there's the distances from the tool string to the perforations of the well.

That's a side view of the same thing. We ran a dipole sonic log in the Bold Venture Number 1 so that they could get a velocity model in order to do their microseismic studies. And there's the perforation timings.

There's stage 1 frac. The little blue diamonds indicate where the microseismic events occurred during that stage 1 frac, and that's a numerical graphic illustration of where those fracs were. As you can see, the very farthest distance normal to the wellbore in stage 1 was a little less than 500 feet. And run a normal curve through there and you're going to get about 200 foot of frac length.

Here's a side view of that stage 1, edge view.

And then we go to stage 2. Stage 2 is our best stage in this well, and we had a fractured half-length of 900 feet, and -- measured normal to the wellbore. And there's the graphic of that. You can see there's just two or three points a little over 900 feet, most of them are right around 700 feet distance normal to the wellbore. That's the fractured half-length that we accomplished in stage 2, as I said, the best stage.

There's the end view. I can't -- because of the position of the tool string, most of the events were heard on the north side of the well. I think if we had any on the south side they were probably masked.

And then this is stage 3. Didn't get a very good frac on that, and/or we were gaining distance from the tool string and we weren't even -- weren't hearing them all.

Side view, end view of stage 3.

Here's stage 4. We only saw one event, and it occurred, instead of where the stage 4 perforations are, way up here. Again, I think the tool string distance had something to do with that.

And then this is a picture of all four stages put together. And you can see the maximum distance is 900 feet normal to the wellbore of fractured events.

A side view of that same thing, and an end view.

And these are the conclusions that Pinnacle made to us about this. Number one reason we wanted to do this study was to figure out where these fractures are going. As Mike mentioned, the predominant fracture direction, natural fracture direction out here, is north-south. Possibility in this well, secondary north 35 east, but we learned what we wanted to about the fracture orientation.

We also learned that our method of completions -- and all the operators complete a little -- similarly, but not -- all not exactly the same. We feel like we have the best mousetrap. We have 900 feet of fractured half-length.

And then they made some recommendations how to change our fracture method, and he recommends 1100 foot of fractured half-length. We achieved 900 on this well.

And next we'll see some production data. As we mentioned, for the Nile Number 1 was the earliers horizontal well produced here. And that Section 22, which is southwest of Artesia, is the only section that has four horizontal wells on it, that has enough time and public data -- public production data to actually see any results. A lot of these wells are so new, there's not enough data, so...

So this Section 22 -- and I'll race through them real quick. Here's the Nile 22 Number 1, a production history.

There's the Jordan Number 1 production history.

The Jordan Number 2, which was drilled in between the first two wells.

And then the Nile Number 2, which is one 160-acre density spacing west of the Nile Number 1.

Then you overlay all four of those together. And I think what you can see immediately is, the decline rate of all these is very similar, very similar.

And then the Nile Number 1, the Jordan Number 1, were completed in '05. And if you notice closely on the production curve, when the other two wells were brought on, relatively soon after each other in early '06, there's no decline -- additional decline, in the first two wells in the production curve. I think we can at least assume that there's no detriment early on that there's interference between these wells.

This is just a cartoon. Those wells were, like I say, drilled early on, so they were all drilled north-south. The Nile Number 1 came on in the first quarter of '05. EUR on that, 1.82.

Now, these EUR numbers we get from our

independent consultants, Colley-Gillespie. They figure out our reporting for us, so they're -- they're numbers that are not EOG's numbers, they are our numbers because we're partners with them in these wells.

So the Nile was here -- the Nile Number 1 was here, first quarter '05.

The Jordan was drilled here, and they were all drilled from the south to the north, so the surface locations are down here. The Jordan can on second quarter '05.

Jordan Number 2 is drilled right in between them, came on first quarter of '06.

And then the -- lastly, the Nile Number 2, and -- shortly thereafter and still in the first quarter of '06.

And all their associated EURs, if you combine all those EURs for the section you get a 5.27 BCF.

And I'll show you in a couple more slides -- and we're near the end -- the volumetrics for that section is 8.8 BCF.

So take those numbers, the recovery factor for this section is 60 percent. Not bad. Not great, but not bad.

All right, this is a single-well drilling economics. This is done also by Colley-Gillespie, using 47-well average, zero a month -- time month production, initial rate of 1.9 million, initial decline of 75 percent and hyperbolic exponent of 2.

And here, as Mike mentioned early, capital expenditure on these wells is anywhere from $2 to $2.5 million. $2.2 million is what we use on this. So believe me, if we could only drill one well in a 320, we would. We'd like to save that money.

But anyway, this single-well economics yields a 1.6 BCF EUR.

This is the 320-acre production unit, gas initially in place. And I used our Walnut Creek Section 16 data to calculate this. I got the temperature and the gross and net thickness from the Swale Number 1 well log and the crossplot porosity from the Swale Number 1. We have 33 foot of net pay, 5 percent weighted average on the porosity there.

The Forego well, which is also in that section, we have a gas analysis on that and we have pressure data on that, so we got that from the Forego well.

The only assumption I'm using here is the water, and I put it at .12 in the dry-gas reservoir. I feel like that's a very good assumption, and in fact it may be a real conservative assumption. After you get the load water from the frac wells back on these wells, they really don't make much water at all. I feel like that's a good assumption.

And then there's all your volumetrics. Bottom line is, gas initially in place for that 320 is 4.4 BCF.

So if we drill two wells on a 320 we would produce 3.2 BCF ultimately. That yields 73-percent recovery factor. If we're limited to only well that would be a 36-percent recovery factor, given the 1.6 BCF to a 4.4.

If you run that number out over the entire 300,000 acres of the field, that's 1.5 trillion cubic feet of gas recoverable that's lost.

And in summary, again, it's a technology-driven play. I think we've shown, and it's been proven over the years, that vertical wells are noneconomic. The only way to make these economic is to drill them with horizontal drilling and slickwater fracs, multi-stage fracs.

We've gone over four major areas of data, the transient pressure analysis along with the core data, the microseismic data, production data and volumetric calculations that show that 160-acre density is recommended.

And to drive the point home again, using two horizontal drain holes per 320 producing unit should be utilized to take advantage of this natural resource.

And revenues from approximately 1.5 trillion cubic feet of gas could be lost to mineral owners and operators and the public by drilling only one well per producing unit over the entire area of play.

That's our presentation. Thank you, sir.

DIRECT EXAMINATION (Resumed)

BY MR. KELLAHIN:

Q. Mr. Durham, is Parallel the only operator in the pool?

A. At the present time, yes, sir.

Q. And within a mile boundary of the current pool boundaries, is Parallel the only operator?

A. Yes, sir.

Q. Do you recommend that the Division adopt special rules and regulations that allow an operator to drill these second wells in a spacing unit in the manner that you've described?

A. I do, sir.

Q. Would it result in an economy effort by the operators and the Division in processing these drilling permits?

A. Yes, sir.

MR. KELLAHIN: We move the introduction of Parallel's exhibits. They've been marked as Exhibit 1, and the pages are numbered, and I think they're all associated with identifications in Exhibit 1 that will allow you to simply admit Exhibit 1 and have everything in the record.

EXAMINER JONES: Okay, Exhibit 1 will be admitted.

EXAMINATION

BY EXAMINER JONES:

Q. Mr. Durham, the -- did you make a -- how many vertical wells would you have to drill to get this same recovery if -- In other words, you looked at, obviously, your economics of your vertical drilling versus your horizontal drilling, and you think you need to drill two horizontal wells per 320; is that correct?

A. Yes, sir.

Q. So you want to keep the spacing at 320 because you want to drill that length of wells, and you don't want to drill any further. Obviously, you've satisfied a lot of your drilling problems.

But if you drill vertical wells, could you ever get the recovery that you're getting from two horizontals in a 320? And then if you did, how many vertical wells would you need to drill?

A. It's just an estimate right now, and I'd say a minimum of eight to ten, but like I say I'm just guessing now.

And your question was worded very wisely. You said, Could you ever get? And I think you could ever get as much gas out of them as you could two horizontals, but it would be a much longer, longer time frame.

Q. Okay.

A. Two horizontal wells -- and it's an estimate -- you know, in 15 years you could probably gain your EUR and those eight or 10 or 15, however many vertical wells. It still would take you 30 -- 25, 30 years to gain that same amount of gas.

Q. And your drilling cost for your horizontals, obviously this play is -- it seems to me like it's been -- I heard you refer to the Barnett shale technology. I don't know anything about the Barnett shale. Maybe you can explain the Barnett shale fracs, for instance, and why you chose them to drill to intersect fractures here, rather than drill along the maximum stress direction and then do the fracs that way.

In other words, these slickwater fracs, is that gel without cross-linker in it, or is it just fresh water, just water?

A. It's just water, there's no gel, no cross-link in there.

Q. So you could only go up to what, two pounds per gallon?

A. We actually on our last frac, which has been -- experimented a little bit, and we achieved three pounds per gallon towards the end.

Q. Toward the end?

A. Yes, sir.

Q. And you've still got 900 feet of frac length?

A. Yes, sir. Well, we did not monitor that one with microseismic. We assume we're getting that much at least.

And our main reason for doing that on the last stage was just to have the very entry point or -- right at the perforations, that part of the frac, just force it open a little more with that extra concentration of sand.

Q. Okay.

A. It wasn't -- the reasoning behind that wasn't to gain frac length or frac height, it was to try to get a higher concentration of sand right at the perforation, right at the beginning of the fracture, hopefully stimulate a little better early-on production.

Q. Okay. That Pinnacle, is that the Pinnacle out of Golden that's doing this for you?

A. Their main office is in Houston, I think. I believe they do have an office in Golden.

Q. Okay. Are they -- They're using microseismic to actually verify what's happening with the frac, along with the fracture simulator; is that right? Are they using the fracture simulator to -- In other words, you're not going to do these microseismics on every well, you just --

A. Oh, no.

Q. -- you just kind of -- So are they using fracture simulator?

A. Well, they'll coordinate with the frac company and look at the simulation prior to the job, and then they'll put the actual frac job rates and pressures in their simulation before their final presentation.

Q. Are they monitoring it live --

A. Yeah --

Q. -- so you --

A. -- it's real-time monitor.

Q. -- you guys watch it in your office while it's going on?

A. Yes, sir.

Q. And so are you drilling to intersect fractures, and then are you -- Tell me about the well construction.

A. All right. Well, you asked about the Barnett shale, and it's a shale, and the reason for putting a high-volume, high-rate frac on that is what they call rubble-izing. You want to get fractures, and they're like spider web or whatever, out into that shale, and it cracks a lot of rock.

And although we're using the same technique, high-volume, rate, slickwater fracs, here it's for a little bit of a different purpose, because this is a dolomite. It's a lime formation, not a shale formation. The rubble-izing is not what we're after here, because that's not what occurred.

We're after creating a set of fractures over the full length of the horizontal in order to drain systematically the whole well.

We do it in four stages. I have several perforation sets per stage and four stages, and there's 144 perforations total throughout the whole well, so we do it in four different stages.

Q. Put cemented casing in the --

A. We cement the long-string production casing with acid-soluble cement, we run in with tubing convey guns to perforate the toe perfs, and then we move in the frac equipment on the day of the frac, we frac the toe, use wireline to pump down a composite frac plug, check valve, if you were, and perforate the next stage and just work our way out of the hole as we frac and perforate alternating.

Q. One day for all that?

A. We usually schedule two days. We're tweaking it now, we're flowing back between each stage now three or four hours, so that takes us two days if you're going to stop and flow back each stage individually for four hours.

Q. Okay. You're drilling them east-west, and they said your fracture going most likely 35 degrees of north; is that right?

A. It depends on where you are in the field. Up near where we are here in that Alysheba, it indicated slightly east of due north, possibly 35. Down in the Hope area it's more -- almost due north-south.

Q. Okay. So the high rate then is what? How many barrels per minute?

A. Eighty barrels per minute.

Q. Wow.

A. And we're doing 80 barrels per minute. EOG is around 60 to 65 barrels a minute right now, and they do have a little gel crosslinker in their last stages.

Q. Oh.

A. Some people use CO_2, some don't. We've used it in the past and are currently not using it, so it's -- we're ever trying to get that best practices and trying to experiment with proppant types and proppant sizes. So it's -- Technology is an ever-changing thing.

Q. Yeah, Mike said that the water is not really a problem in the Wolfcamp, but you're putting in a lot of water with these frac jobs.

A. Yes, sir. And we have to use quite a bit of additives like biocide, scale inhibitors, friction reducers because of the high rates, microemulsion surfactant to enhance the wettability of the rock and try to get all frac water out as quickly as possible. So there's some add- --

it's just not fresh water, there are additives involved.

Q. And you don't put pumping units on them, you just flow them?

A. No, for the most part -- and we've drilled over 30 wells and producing them all right now. We have not drilled a dry hole. There's a wide variation in the amount of production. There's some that are very marginal, even submarginal, and some that are barn-burners. But we haven't drilled a dry hole yet.

And there's two of them, actually, we have temporary pumping units on there, to get some of the water off of them. They're very low-volume wells, and so we are -- For the most part, they're dry gas flowing wells.

Q. The pipeline or gathering system is in place out here, or are you guys having to construct that?

A. We -- actually, in the area we're talking about here, Walnut Creek, we have built and constructed our own pipeline. We have a small gas plant just south of Hagerman, and our pipeline goes all the way to Transwestern main line, east of the Pecos River.

Q. That economics is built into your whole system --

A. Yes, sir.

Q. -- developing this?

Would you envision -- You guys are wanting to drill two wells per 320, but are you going to start out just drilling one per spacing unit and then see how that goes and then come back later and drill --

A. That would be in our --

Q. -- hedge your bets a little bit here?

A. That would be our technique, mainly because you want to see. If you've got a well that's a real fantastic well, I think you'll produce it a while and move on to other sections before you even consider drilling a second well on that 320.

Q. Okay. And what did your cost start out at, in these horizontal wells? You said you're down to $2.2 now, but --

A. Well, and that's --

Q. -- there's always a curve on that.

A. That's kind of an average. We are actually drilling two wells from one pad in a lot of cases. For instance, the Swale Number 1 in Section 16, and the other well, we call it a sister, it's All Along Number 1, is in Section 17. They were both drilled off the same drilling pad, wellheads are 18 feet apart. And we drilled them in such a way that by the time they reached horizontal they were orthodox or 660 from the section line, and then drilled the lateral.

So we try to save money like that. Not only money, we disturb a lot less ground like that, and we're getting better at drilling, the days are coming down. So I'm going to say the range there at one time was probably $2.3 to $2.8 million, and that range is probably now from, say, $1.8, $1.9, up to about $2.2, $2.3 million.

And it depends on the trouble you have. There's quite a bit of surface trouble here, lost circulation in that -- in the shallower zones, and sometimes it gives you a lot of trouble and sometimes not.

Q. Have you lost any wells that you've had to redrill?

A. We've actually skidded the rig on two wells, and they all had to do with surface problems, very shallow, boulders or sugar sands or something that got us stuck, and we had to plug back and skid over and attempt it again.

Q. Before I forget, I'd like to thank you guys for putting on a good -- nice thorough, scientific show here, and I think you did a really -- really good job. And I have a few more questions here, but...

The cores you took were vertical pull cores --

A. Yes, sir, they were --

Q. -- sidewalls or anything?

A. -- they were oriented cores in the vertical pilot hole.

So not only did we gain the data for permeability and porosity, we also used the orientation of those cores that came out of the hole to estimate fracture direction also.

Q. Okay. Speaking of that, what was the date of that show that happened on the --

A. I believe it was February 13, if I'm not mistaken.

Q. February 13.

A. '07.

Q. Okay. Okay, the -- Obviously, you're considering this to be the same -- like a common source of supply, but I guess as far as our mile-long -- mile between pools it becomes a wildcat, according to our rules, but --

MR. KELLAHIN: Well, the concept here was to play off of what was presented in February and give you a formal transcript and a case number to make a decision by the Division if you want to take this as a type example and extend this rule to the whole play --

EXAMINER JONES: Yeah.

MR. KELLAHIN: -- which may be convenient for everybody and would eliminate the need to file these individually or have multiple hearings on various areas of what turns out to be the same common source of supply.

So it's an administrative decision for the Division to make in terms of the scope of what this evolves into, but we certainly would encourage you to use this as your model to do that.

EXAMINER JONES: And in particular for this hearing, the Walnut Creek Pool is what you're going for now though?

MR. KELLAHIN: That's our specific --

THE WITNESS: Yes.

MR. KELLAHIN: -- request as of --

EXAMINER JONES: Okay.

MR. KELLAHIN: -- this hearing.

EXAMINER JONES: And as a result, it wouldn't require any more notice to people around -- to everybody around if you drill two wells -- two horizontals per 320?

MR. KELLAHIN: The procedure was, if we're within a mile of the outer boundary of this with the next stepout, then we could drill it without the requirement of additional notice.

Then as the pool expands, if that is the sequence, it will eventually encompass the whole area, and then you'll have the problem of how you integrate this pool with the Cotton Creek [*sic*] --

EXAMINER JONES: Okay.

MR. KELLAHIN: -- which is on the same spacing unit.

Q. (By Examiner Jones) Okay, I guess one more little question. You'd be drilling -- is that water-based, normal pressure drilling?

A. It is water-based, and normal to underpressured.

Q. To under?

A. Yes, sir. We have very -- lost circulation problems in the upper hole quite frequently. And then in the zone itself horizontally, drill with about a 9.2 mud only, because there are some shale streaks in there, and if you get them wet they will slough off and fall in on it. So you have to have that mud weight to hold that shale back.

As far as pressure is concerned, you could probably drill it with 8.3 water really easily if you didn't have that shale to contend with.

Q. What's your rate of penetration?

A. Anywhere from 30 to 130 feet an hour, depending on if -- if you're in the best porosity -- and that's where we try to stay, because that's where you're going to get the best gas and the best permeability -- it drills faster there also.

Q. Is that how you tell where you're at?

A. Yeah, we have a mudlogger out there, and we have a rate of penetration --

Q. Okay.

A. -- and Mike and I keep up with it every -- not just every day, all day, while we're in the horizontal.

Q. That's interesting.

You said that you'd get a show if you're -- if you get any porosity on your density log, which is kind of interesting, you don't have a three-percent cutoff or something like that.

So I assume this is limestone matrix logs that you're running on this stuff?

A. Yes, sir.

EXAMINER JONES: Okay, David? You've been looking at these for --

EXAMINER BROOKS: Well, I wouldn't undertake to ask any questions on the technical aspects of it, but perhaps Mr. Kellahin would be the person who would answer the questions that I would have.

Other than -- Well, let me get back to the map that you had here. Where is the area map that showed the -- Yeah.

Are there any existing Wolfcamp pools in this area that -- other than this one and the Cottonwood Creek, that are part of this play?

MR. KELLAHIN: To the best of my knowledge, there are not.

EXAMINER BROOKS: Okay, so the Cotton- --

THE WITNESS: Well, there's a --

MR. KELLAHIN: Yes, sir.

THE WITNESS: -- there's a pool called the -- I believe, the Lake Arthur, which is actually over by the town of Lake Arthur.

EXAMINATION

BY EXAMINER BROOKS:

Q. Now this -- this -- I started to say rectangle, but it's not a rectangle -- this rectangle with a nick in the upper right-hand corner --

A. Yes, sir, that's Lake Arthur.

Q. Is that the Lake Arthur Pool, or is that the town of Lake Arthur?

A. Well, that's the town of Lake Arthur. The well is directly north of there. You'll see the symbols north and a little east, continue north there.

Q. Yeah.

A. WITNESS: Right up there where the gas symbols are.

Q. Up in this area?

A. Yeah, these are --

Q. Up --

A. -- these wells are considered -- and I don't know the exact name of the pool, but I believe it's called the Lake Arthur-Wolfcamp Gas Pool.

Q. And that's in the north part of 15-26 and the south part of 14-26?

A. Yes, sir.

Q. Okay. Now where is -- This pool is in 16 of 15-25?

A. Yes, sir.

Q. The Walnut -- what's the --

A. Walnut Creek.

Q. Walnut Creek Pool is over in 15.

And then down in Eddy County, in 16 South, is where the Cottonwood Creek is?

A. Yes, sir, and that now also extends one section to the north --

Q. Is that over here --

A. That's --

Q. -- or --

A. -- our Cottonwood Creek Pool.

Q. Okay. And as far as you know, are those the only pools that are in this play, the only existing pools, Wolfcamp pools that are in this play?

A. The --

MR. KELLAHIN: Let me call Mike Gray, he's studied all the pools.

Mr. Gray, come forward.

For the record, this is Mr. Mike Gray. He's a petroleum landman with Parallel and he has been studying all these pools.

MIKE 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, can you respond to the question?

A. Yes, they're south of the -- of our Application pool, south of the Cotton- --

Q. Walnut.

A. -- Walnut Creek. There's a -- the Cottonwood Creek field, which is directly south.

There's also a Cottonwood Creek west field that is contiguous to Cottonwood Creek to the west in the --

EXAMINER BROOKS: This is not -- I have -- this is probably -- Go ahead.

THE WITNESS: The -- Anyway, Cottonwood Creek is directly south and southwest of this field and goes for several miles to the south in 16-25. Cottonwood Creek West is also a Wolfcamp Pool that is contiguous to Cottonwood Creek, just west of it, and it also goes for a few miles south from the county line and a little bit into 15-24 in Chaves County.

There's also -- we also have a -- we have a new field, a newly designated field in Section 36 of 14-25, newly designated by the District as the Hagerman Ditch field.

EXAMINATION

BY EXAMINER BROOKS:

Q. So the Hagerman Ditch field is in 36 of 14 --

A. -- 14-25, right.

Q. -- 25?

And the Lake Arthur-Wolfcamp is up in --

A. It's in 14-26 --

Q. -- 14-26.

A. -- and 15-26.

Q. Okay. And the Cottonwood Creek Wolfcamp is down in Township 14 -- Township 16 South?

A. It's -- Yeah, it's in the very southern -- in the southern tier of sections. It now encompasses Sections 32 and 33 of 15-25 and then goes several miles south of there.

Q. Okay, and then the Cottonwood Creek West is over in 16-24?

A. Right, and it -- and it's -- and it's in -- yeah, 16- -- the west part of 16-25 and into 16-24 and up into 15-24.

Q. And as far as you know, is that all the pools that are --

A. In this --

Q. -- pools --

A. -- in this vicinity, in the 50-mile play, there are -- I can't tell you how many pools there are. There may be half a dozen or more.

Q. Okay, so there are other pools that would be in this play?

A. Yes, all the way down to, you know, 10 or 12 miles south of Hope.

EXAMINER BROOKS: And I guess I would address this to the engineering witness, then. The considerations that were a part of your presentation would apply to the entire play, if I understand --

MR. DURHAM: Yes, sir, I believe they do.

EXAMINER BROOKS: The entire 50 miles?

MR. DURHAM: Yes, sir.

EXAMINER BROOKS: Okay. I think that's all the questions I have.

EXAMINATION

BY EXAMINER JONES:

Q. Mike, when you noticed people for this hearing, you guys said you noticed all the revenue interest owners in the Walnut Creek Pool; is that right?

MR. KELLAHIN: We notified the interest owners in 16 and in the south half of 17 and the offsets.

EXAMINER JONES: 16 and the south half of 17 --

MR. KELLAHIN: And if you take a boundary around that as if you were filing an administrative application, we just sent those notices to the same people that we sent notices to for the administrative approval for the Swale pairs.

EXAMINER JONES: Okay.

EXAMINER BROOKS: So you didn't -- you didn't do a one-mile radius around the current pool boundaries?

MR. KELLAHIN: Well, there was no other operator but Parallel.

FURTHER EXAMINATION

BY EXAMINER BROOKS:

Q. Okay. I guess -- Let's see, the current boundaries of the -- the current boundaries of the pool are -- is it only Section 16?

A. It's all of 16 and the south half of 17.

Q. And that's in --

A. 15-25.

Q. -- 15-25.

A. Yes, sir.

Q. So you're talking about 16 and the south half of 17.

And if you go -- Is Parallel the only operator all the way around?

A. We either have -- we have all the offsets either permitted, or there is no permit or operator in -- Parallel -- I can tell you, if you're looking at the map. Parallel has permits in -- and you can -- the --

MR. MOYLETT: They're on the map.

THE WITNESS: -- Section -- Yeah, Section 9 is permitted, Section 8 is permitted by Parallel, Section 20 is permitted by Parallel, Section 21 is permitted by Parallel, the south half of 10 is permitted by Parallel, the north half of 15.

I don't believe there is a permit in the south half of 15 right now. There's no permit in the north half of 22, and there's no permits in Sections 18 and 19.

Q. (By Examiner Brooks) All these wells that are shown on here are permitted by Parallel?

A. All the wells within -- yes, within a mile of the field, of the new pool, are permitted by Parallel.

EXAMINER BROOKS: Okay, I believe that -- I believe that covers it, but...

FURTHER EXAMINATION

BY EXAMINER JONES:

Q. While he's looking, the EOG people didn't want to coordinate with you guys on this presentation?

A. The -- One of the problems, and one reason -- one reason we're here now, as opposed to next month or a month from now, is, the -- as these fields grow, the notice provisions become either unwieldy or impossible, because you have -- you know, the Cottonwood Creek field is a huge field now, and it's going to take lots and lots of notice.

Although if it's the operator only, then it's a lot simpler than, for instance, the notice for the increased density well, which requires basically notice to everybody and their dog.

But the -- as these fields grow -- and another problem is -- is, you know, we're completing a well out here every 15 or 20 days, and if Bryan puts it into field every time we -- you know, every time we bring one on, you'd never finish. The field is going to grow faster than you can get a hearing scheduled. So...

EXAMINER BROOKS: Yeah, it looks like it is only operators within one mile of the pools.

MR. KELLAHIN: That's the rule I was looking at. It's 1210.B.(4).(b).

EXAMINER BROOKS: That would appear to be the applicable rule.

THE WITNESS: And again, I'll stress Tom's comment. If it would be possible to take this presentation and do some kind of consolidation, at least in this area, it would be really helpful to both the operators and to the Commission, because you guys are going to get these increased density applications -- they're just going to pour in as these fields are developed and infilled.

EXAMINER JONES: Well, that's something that we have to talk about --

EXAMINER BROOKS: Well --

EXAMINER JONES: -- or have a conference about or something.

EXAMINER BROOKS: -- that's true, because the way that Richard would like to see it done is to get -- have pool rules applications for -- or special pool rules for all the pools that are affected, and --

THE WITNESS: The -- and I'll tell you, my perspective on this is that Cottonwood Creek, for instance -- I think EOG's -- I mean, they've got a machine that generates those applications, and it's in -- and I don't -- and the Division probably doesn't have a machine to approve them.

EXAMINER JONES: He's the machine.

THE WITNESS: But the -- Cottonwood Creek -- or EOG's portion of Cottonwood Creek is very rapidly being drilled up --

EXAMINER BROOKS: Yeah.

THE WITNESS: -- and the infill wells are for the most part in place, or many of them are. They no longer have an interest in changing the field rules because --

EXAMINER BROOKS: Yeah.

THE WITNESS: -- they're about through.

As the field expands to the south on the other operators, though, you're going to have the same problem.

EXAMINER BROOKS: Okay. Well, we appreciate your bringing this before us, and as Will says, we appreciate your thorough and professional presentation.

EXAMINER JONES: Okay, that's -- that's everything?

MR. KELLAHIN: Yes, sir.

EXAMINER JONES: With that, we'll take Case 13,986 under advisement.

Let's have a 15-minute recess.

(Thereupon, these proceedings were concluded at 10:05 a.m.)

* * *

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

______________________, 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 September 24th, 2007.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2010