STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO

1 April 1987

COMMISSION HEARING

VOLUME 3 of 5 VOLUMES

IN THE MATTER OF:

Case 7980 being reopened pursuant to the provisions of Commission Order No. R-7407. . . Rio Arriba County.	CASE 7980
and	
Case 8946 being reopened pursuant to the provisions of Commission Order No. R-7407-D. . . Rio Arriba County.	CASE 8946
and	
Case 8950 being reopened pursuant to the provisions of Commission Order No. R-2565-E (R-6469-C) and No. R-3401-A. . . Rio Arriba County.	CASE 8950
and	
Case 9113, application of Benson-Montin-Greer Drilling Corporation, Jerome P. McHugh & Associates, and Sun Exploration and Production Company to abolish the Gavilan-Mancos Oil Pool, to extend the West Puerto Chiquito -Mancos Oil Pool, and to amend the special rules and regulations for the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico.	CASE 9113
and	
Application of Mesa Grande Resources, Inc. for the extension of the Gavilan-Mancos Oil Pool and the contraction of the West Puerto Chiquito-Mancos Oil Pool, Rio Arriba County, New Mexico.	CASE 9114

BEFORE: William J. LeMay, Chairman
Erling A. Brostuen, Commissioner
William R. Humphries, Commissioner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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A P P E A R A N C E S CONT'D

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I N D E X

I N D E X CONT'D

E X H I B I T S

E X H I B I T S CONT'D

(Thereafter at the hour of 8:30 o'clock a.m. on Wednesday, 1 April 1987, the hearing was again called to order and the following proceedings were had, to-wit:)

MR. LEMAY: The meeting will now come to order.

We shall resume with Cases 7980, 8946, 8950, 9113, and 9114, with Side Two.

Mr. Lopez, is there any connotation you'd like to be known by?

Mr. Pearce?

MR. PEARCE: The good guys.

MR. LEMAY: The good guys?

MR. LOPEZ: Mr. Chairman.

MR. LEMAY: Mr. Lopez.

MR. LOPEZ: It may not come as a great surprise to the members of the Commission but there exists sharp disagreement with respect to the understanding of these two pools between the parties.

In fact, it would be accurate to say that the conclusions that the respective parties have reached are simply contradictary, and it is not without great interest because of the great investment that this side of the table (not understood) because unquestionably, and I'm sure the other side of the table sees it the same way, we want the biggest bang for our buck.

However, I intend to be very brief in my opening remarks simply because I think it's better to leave the testimony to the experts and let them speak for themselves. I don't see any purpose to be served by inexpert attorneys putting words in their mouths.

In this vein I would like to simply frame the issues as we see them and I think that there are several points I'd like to make.

We believe and are confident that the evidence will show that the Gavilan Mancos Pool produces principally from the Niobrara A and B intervals and is weakly connected with the West Puerto Chiquito Mancos Pool, which produces primarily from the C Zone.

Second, the Gavilan Mancos Pool is a dual porosity, not a single porosity, system, consisting of a high capacity fracture system and a low flow capacity fracture, microfracture, and matrix system.

Third, ultimate recovery in the Gavilan Mancos Pool is not sensitive to producing rates if it is produced on 320-acre spacing within the limits of applicable statewide rules, namely 702 barrels of oil per day with a limiting gas/oil ratio of 2000 cubic feet of gas to one barrel of oil.

Producing the pool on this basis would prevent waste, would not cause waste, which would occur if the McHugh/Greer proposal was adopted.

Fourth, if the Gavilan Mancos Pool is produced in accordance with statewide rules on 320-acre spacing, it will not adversely affect the production in the West Puerto Chiquito Mancos Pool subject to the established gas injection project operated by Mr. Greer.

Fifth, the wells along the western boundary of the West Puerto Chiquito Mancos Pool are primarily in communication with the wells in the Gavilan Mancos Pool and therefore the pool boundary should be established as proposed by Mesa Grande.

This proposition is further supported for geological reasons, namely, the existence of the syncline in the area and operational reasons, such as namely the terminus of Mr. Greer's injection project.

Sixth, the Gavilan Mancos Pool is a heterogeneous, complex reservoir with significant highly varying reservoir characteristics present throughout the pool, a fact that is supported by direct offset wells varying significantly in producing capacities and recoveries.

And finally, seventh, two wells

of limited capacity but of comparable quality spaced on 320 acres will have significantly more recovery than a single well of quality equal to the two wells spaced on 640-acre spacing.

A regime of restricted allowable recovery more severe than that permitted by the statewide rules, will result in a redistribution of remaining recovery amongst the other wells in the Gavilan Mancos Pool; hence, for the reasons already described, oil in place cannot be determined for individual proration units; 320-acre spacing, subject to statewide rules, is the optimum method of protecting correlative rights.

And I hope that was brief enough and with that I will call our first witness, Mr. Emmendorfer.

ALAN P. EMMENDORFER,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. LOPEZ:

Q Would you please state your name and where you reside?

A My name is Alan P. Emmendorfer and I

reside in Tulsa, Oklahoma.

Q By whom are you employed and in what capacity?

A I'm a petroleum geologist for Mesa Grande Resources and I provide exploration and development geological services.

Q Have you previously testified before this Commission and specifically in previous cases involving the issues being addressed by the Commission today?

A Yes, I have.

Q And were your qualifications accepted as a matter of record?

A Yes, they were.

Q Nevertheless, would you briefly describe your educational background and employment experience?

A I received a Bachelor of Science degree in geology in 1977 from Southeast Missouri State University and then went on to the University of Oklahoma where I received a Masters degree in geology in 1979.

In the fall of '79 I went to work for El Paso Exploration Company in Farmington, New Mexico, and performed development geological tasks in the San Juan Basin for approximately five years.

And then in the late summer of 1984 I went to work for Mesa Grande Resources in Tulsa as a geologist.

Q Are you familiar with the Gavilan Mancos Pool and have you made studies in connection therewith?

A Yes, I am.

MR. LOPEZ: I would tender Mr. Emmendorfer as an expert geologist.

MR. LEMAY: His qualifications are acceptable.

Q Mr. Emmendorfer, I would ask you to now refer to what's been marked Exhibit Number One and identify it.

Would you please describe this exhibit and explain what it shows?

A Mr. Chairman, I included this first exhibit, which I've entitled as Type Log, for reference purposes.

We have here the Gavilan No. 1, which was originally drilled by Northwest Exploration Company, and it is -- has been considered the type log for the Gavilan Mancos Field. It's -- the vertical limits of that pool, as defined by Order No. R-7407, are listed and shown on the righthand side of the log.

The Gavilan No. 1 Well was also used as the type log in the subcommittee portion of the Gavilan Study Committee. In that committee we attempted to map the geology of the Gavilan Mancos area and we picked tops, namely the Niobrara A Zone, the Niobrara C Zone, and the Niobrara -- Niobrara Zones, A, B, and C, and the Sanostee.

We used the Gavilan No. 1 Well as a reference and from this reference log were able to correlate these tops throughout the area; the area including the Gavilan Mancos Pool, the West Puerto Chiquito Pool, wells in the West Lindrith Gallup-Dakota Pool, wells in the Ojito Gallup-Dakota Pool, and wells in the Northeast Ojito Gallup Pool.

These intervals were easily traced throughout the area.

I've also included on here the geological names for the formations. It gets kind of confusing when one person says "Gallup" and the next person says "Niobrara" and then they talk about pools, and all, but the Gavilan Mancos interval is of Upper Cretaceous age in the Mancos interval and a common term for the Niobrara A, B, and C Zones used by industry people is the Gallup.

Q Is that all you have to say about this exhibit?

A Yes, it is.

Q Now I'd like for you to refer to what's been marked as Exhibit Two and ask you to explain that.

MR. LOPEZ: Mr. Chairman, we're going to put this exhibit up on the wall and I'll ask Mr.

Emmendorfer to approach the exhibit and explain it.

A Exhibit Number Two is a structure map mapped on top of the Gallup or the Niobrara A Zone. The datums used to construct this structure map were the configuration of the calculations from the data provided to the Geological Subcommittee members taken at Kelly bushing and the top of the Niobrara A Zone, thus gettng the data for the top of the Niobrara A.

Contouring it up we see two separate structural entities separated by a north/south trending synclinal axis.

I would like to first refer you to the east side of this structure map where we have West Puerto Chiquito Pool. The pool extends past this map. I think the important thing to see here is that coming out of the trough the dips start at about zero in the trough and proceed up to a maximum of 6 degree of dip.

There is a gross structural difference of approximately 2600 feet within from the center of this syncline to the end of West Puerto Chiquito Pool.

In the central portion of the structure map we have a gently dipping Gallup -- or the gently dipping Gavilan Dome, which is central to the Gavilan Mancos Pool. The dips average within the Gavilan Mancos Pool, average about .6 degrees throughout the producing area.

We have the general axis of the San Juan Basin occurring in Range 3 West and trending to the northwest.

The structural difference in the Gavilan -- on the Gavilan Dome, within the Gavilan Mancos Pool goes from a high of approximately 570 feet above sea level to about 200 feet above sea level, roughly a little over 350-370 feet of vertical relief.

It's different from the West Puerto Chiquito area where the -- as I mentioned earlier, the contour interval, if you were to take this out to the eastern edge of West Puerto Chiquito Pool, is at 3000 feet above sea level and the datum of the Niobrara A top injection well that occurs the farthest east in the West Puerto Chiquito Pool is a positive 200 -- 2,537 feet above sea level, so there is a gross difference in structural relief between the two areas.

This is separated again by the anticline -- or the synclinal flexure located between Sections 18 and 17, 25 North, 1 West, with this syncline running north/south.

Q What is the degree of dip for the West Puerto Chiquito?

A Well, it varies, but it goes from zero at the base in the center of the syncline up to 6 degrees in the area of the wells, the high capacity wells that have produced the majority of the reserves in the West Puerto Chiquito Field.

We have -- going from about a mile between the 10 Well and the L-11 Well in the West Puerto Chiquito Field, we have about 600 feet above sea level to 800 feet above sea level.

Another mile from the L-11 Well to the A-14 Well, goes from 800 feet above sea level to approximately 1200 feet above sea level.

Q I believe you stated that the degree of dip in the Gavilan Mancos was .6 of a percent?

A That's the average for the Gavilan Mancos Pool.

Q So we have on a magnitude of ten times the difference in degree of dips between the two pools.

A That's approximately true, yes.

Q And I see an outline of the dark black line. What does that portray?

A Okay, I've also included on the structure map the proposed Gavilan Mancos Pool boundary that our company has requested. The purpose of including it on the structure map was to show the eastern boundary of this pool as it would relate to the structural difference between the two pools occurring along the axis of the syncline separating the two pools.

Q I'll ask you to refer to the next exhibit, Exhibit Three, which we will also put up on the wall, Mr. Chairman, and as you see there is a cross section indicated on the structure map, which will tie in with the next exhibit.

Will you now describe what is shown on Exhibit Three?

A Exhibit Three is a structural, general east/west structural cross section through a major portion of the West Puerto Chiquito Field, extending through the Gavilan Mancos Field -- Pool, into the Ojito Gallup-Dakota Pool.

I'd like to refer you back to Exhibit Number Two to show you the general east/west trace of the cross section through the wells that are on the structure map.

This, I should mention first that the structural cross section is not a true structural cross section in the sense that it exhibits true structural configuration from point A to point A', but it is a structural cross section in that it serves to show the structural elevational differences between each of the different wells.

But it does serve to illustrate that on the western -- or the eastern portion of this cross section we have the steeply dipping monocline which is characteris tic of the West Puerto Chiquito Pool, coming into the synclinal flexure and then over the -- what I have shaded in green, the Gavilan Dome, which is the Gavilan Mancos interval, and then leveling off as it gets into the Ojito Gallup-Dakota Field.

I've also included on each of the wells in the cross section the gross productive interval and this highlighted in red vertical bars on the well logs of each of the wells that are on this cross section.

There are two wells that have not been completed yet. They're in the Canada Ojitos Unit so I should not put what that producing interval is.

In the -- this red swath of line in the eastern three wells on the cross section in the West Puerto Chiquito Field serve to show the main producing interval over in that portion of the monocline, and you'll notice that the -- all the production within these three wells comes from a narrow band within the C Zone.

Over the Gavilan Dome in the Gavilan Mancos Pool we have -- we see that most of the wells are produced at a -- the gross productive interval is much larger; however, geological evidence and production evidence has shown to us that a majority of the production comes out of the A and the B Zones, thus we've highlighted in darker green the A and B Zone productive intervals, and to a lesser extent the C and the Sanostee intervals. I've not colored in the productive horizons in the Ojito Gallup-Dakota wells because I don't have the information as to where the majority of the production is coming from.

I mentioned earlier that the Canada Ojitos Unit No. 33 was not completed yet. I do have it shaded in because I do believe that it is a part of the Gavilan Mancos Pool just by the fact that it is on the west side of the syncline and geologically should be included in the pool.

The Canada Ojitos No. 24 Well, commonly referred to as the J-8, has a large gross productive interval. It extends from above the A Zone in what some people refer to as the gray area, the gray zone, down through the Sanostee.

I didn't color that well in, just where the major productive interval is, because as I was studying the area, I just could not figure out where the four barrels per day was coming from throughout this gross productive interval, so I left that off of the cross section with the coloration of where the major production was coming from.

Q Okay. Would you take your seat, then, and -- excuse me a minute.

Would you please now describe for me the porosity system in the Gavilan Mancos Pool?

A Our group feels that the porosity system within the Gavilan-Mancos Reservoir consists a dual porosity system. We have a high capacity fracture system and then we have what we loosely define as a matrix porosity system. this matrix porosity system consists of low capacity fractures, microfractures, and the strict geological definition of matrix porosity in that it would be true sandstone porosity, intergranular, interparticle porosity.

Q So when you say matrix porosity system, do you necessarily mean a typical sandstone porosity system?

A No, I don't. Like I said earlier, we have varying degrees of matrix porosity. We have the strict definition of intergranular porosity. We have these microfractures that are in communication with this, and we also have low capacity fractures that are also in comunication with all three, and we have a varying degree or amount of this matrix porosity in any one area of the reservoir.

Q Do you have any evidence of this matrix porosity system, and in this connection I'd like for you to refer to what's been marked for identification as our Exhibit Four.

A Exhibit Number Four are some examples of sample shows from mud logs from wells drilled in the Gavilan

Mancos.

What I would like to show with this exhibit is that mudloggers that routinely sit on most of the wells that are drilled out in this pool, record intergranular porosity and hydrocarbon sample shows routinely from sandstone cuttings as they are drilled through -- as they come up from the wellbore as drilled through the Gavilan Mancos interval.

The first hydrocarbon show sheet after the title page is from the Mallon Oil Company's Post Federal 13-6, which is located in Section 13, 25 North, 2 West.

Q And, Alan, I might have Larry go show where that well is located on the structure map.

A Thank you.

Q Okay.

A In Section 13, 25 North, 2 West.

Now, as a matter of industry practice whenever you have a mudlogger sitting on a well, his job is to describe the drill cuttings as they come up the hole and relate this back to the geology of the formation in the wellbore.

They've described these samples as to their lithology and then if they have any suggestion that there might be some porosity within these cuttings, they put it under an ultraviolet light and subject it to a solvent to see if they can get a hydrocarbon show from any of these samples, and the porosity contained within these samples.

As I mentioned, this exhibit is an example from the Post Federal Well, an interval from 7,050 to 7,062, which is in the Niobrara A Zone, was logged. There was a lithology of a sandstone. The mudlogger reported that they had intergranular porosity. Although the porosity was poorly developed it was the porosity present. There was a good stain, oil stain, poor fluorescence, although it was even, and that he was able to get a slow streaming cut from this sample.

The next three pages of the exhibit are sections I Xeroxed from three different mud logs from three different wells that Mesa Grande Resources has drilled. The first one is the Bearcat No. 1 in Section 22 of 25 North, 2 West.

Q Okay, Larry is pointing that out on the exhibit.

A The second one is the Invader Federal No. 1, which is in Section 1, 24 North, 2 West.

And the third one is the Gavilan Howard No. 1, drilled in Section 23, 25 North, 2 West.

I want to point out also that of these three mud logs, they're from two different mudlogging companies and they are also a separate mudlogging company from the mudlogger that mudlogged the first sample here in my exhibit book.

I've highlighted on the mudlog where they have noted the quality of the sandstone with exhibiting hydrocarbon fluorescence in cut from several different samples up and down the Gallup -- the Niobrara A and B intervals. You can see on each of these three mudlogs where the mudlogger has picked the top of the Gallup or the Niobrara that occurs toward the top of the mudlog on these three examples.

Finally I would like to refer you to the last two show sheets, and they're the last two pages of this exhibit.

Both of these show sheets are from the same well, the Mallon Oil Company Davis Federal Com 3-15. This is located in Section 3 of 25 North, 2 West.

The first of these two show sheets is from a depth of 7,030 feet to 7,078. If you were to look on the induction log, this would be in the A Zone, above the interval that was cored.

Again this mudlogger recorded sandstones within these drill cuttings containing intergranular porosity with a good hydrocarbon fluorescence and a good streaming yellow cut.

The last page is the second show sheet

from this same well, the Davis Federal Com 3-15. The important thing to see here is that this -- these samples were logged during the course of coring the B Zone of the well. The cuttings that the mudlogger reported were intergranular -- fairly well developed intergranular sandstone porosity with a fair, even hydrocarbon fluorescence and a good cut.

Again he noted, he remarked that these shows were from the drill cuttings while drilling the B Zone.

I think this is significant, Mr. Chairman, in that the routine core analysis that we had done by Terra Tek, everybody generally says that there's no matrix porosity within the core, yet the mudlogger reported cuttings coming from the same interval that the core was cut and recorded hydrocarbon shows. This is a continuity with all the other mudlog examples I have here. They're from different operators, different mudlogging company, and within the same mudlogging company, different mudloggers, and this is a standard tool within the industry of locating matrix producing reservoirs.

Q I'd now ask you to refer to what's been marked for identification as Exhibit Five and ask you to describe it, but before you do that I'd like you to explain what the purpose of this exhibit is, so let's do that.

Okay, Mr. Emmendorfer.

A Exhibit Number Five is a general north/south cross section between the two wells that were cored extensively throughout the Niobrara productive interval in the Gavilan Mancos Pool.

I would like Larry to point out for me on the structure map where these wells are located.

The one to the north is Mallon Oil's Davis Federal Com 3-15. It's located in Section 3, Township 25 North, 2 West, in the northern portion of the Gavilan Mancos Pool.

The other well, located on the -- in the southern portion of the pool is the Mobil Lindrith B Unit No. 38, located in Section 4, Township 24 North, Range 2 West.

What this exhibit serves to show is the visual sand/shale ratio of foot by foot description of the cores as they relate to the induction logs within the Gavilan Mancos Field.

We've heard testimony that routine core analysis -- or routine wireline log analysis does not truly reflect what is within the Niobrara interval. What I did was I took the -- the sand/shale ratios as described by the people that did a foot to foot -- foot by foot description of the cores, plotted this ratio up and then correlated it onto the induction log of the two wells.

On the Mallon well, the Davis Federal Com 3-15, the study committee had this core analyzed and Terra Tek, an organizaiton out of Salt Lake City, took a foot byl foot description of the core and visually estimated the percent of shale and sand within this foot. I made that into a graph form for you here.

Likewise, in the Mobil well, the geologist that describes the core foot by foot, he also did a visual sand/shale ratio plot of the well.

I examined both of the cores and I visually did a rough estimate of sand/shale ratio plots and was in close agreement with both of the geologists that did the official sand/shale ratio plots that I have shown on the cross section.

I think that it's important to see, Mr. Chairman, that the A and the B Zones exhibit the high concentration of sand in relation to shale.

In the bottom of the -- in the base -- or below the high resistivity C Zone of the Davis Well, which we were able to core through, we have another spot on the graph that shows that there is a high sand concentration within this area.

In looking at the core, or the core photos, there's a definite genetic difference between these sandstones, between the A-B Zone and this sand that's plotted in the lower C Zone.

The A and the B Zones sandstones are bedded, sandstones that are bedded within evenly bedded sands that are bedded within the shales. The sands that are in the base of the C Zone below the high resistivity seam could be described more accurately as a furrowed mudstone where the sands and the shales have been furrowed together and there is no true bedding between the sands and the shales.

Q Are you saying that the interbedded sands and shales in the A and B Zone is different than the furrowed mudstone that we find present in the lower C Zone of the Mallon Well?

A Yes, their stratigraphy is different and I believe that their porosity, then, would be a little different.

Q Does this mean that this high concentration of sand in the lower C Zone is not productive?

A I don't think that it would not necessarily be nonproductive. I think that it does have hydrocarbons present. I think, though, necessary to make a commercial, producing effort out of this sand concentration in the C Zone, you would have to have a well developed, high capacity fracture system to do so.

Q Then which intervals in the Gavilan Mancos Pool do you consider highly fractured, and in this connection I refer you to what's been marked as Exhibit Six. Would you explain what this exhibit is and describe what it shows?

A Exhibit Number Six, Mr. Chairman, is a general north/south stratigraphic cross section using fracture identification logs, that highlight, effectively highlight what I consider the main highly fractured producing interval within the Gallup -- Gavilan Mancos Pool, and in that respect I would like you to refer to this exhibit and I've highlighted in green here on the map the -- what I consider to be the highly fractured interval, and this is concentrated within the A and the B Zones of the Niobrara.

This cross section is made up of four wells and we'll start from the south, then, which is on the lefthand side of the cross section, the Mobil Lindrith B No. 74, located in Section 9, 24 North, 2 West; the Bearcat No. 1, Section 22, 25 North, 2 West; the Canada Ojitos Unit No. 33, Section 18 of 25 North, 1 West; and finally the Canada Ojitos Unit No. 32, located in Section 6, 25 North, 1 West.

Q So these four wells pretty much cross the reservoir in the Gavilan Mancos Pool.

A Yes, they do. What we have in the course of drilling these wells some operators have run a log referred to as an oriented fracture log. This log is a dipmeter log; however, the logging companies that constructed the computer did not calculate dips of beds, but they used the instructed the computer to -- to read the microresistivity of the formation and sort out what they considered to be anomalies, and this is generally interpreted to mean fractures.

The dipmeter tool consists of a four-armed pad, each of these pads oriented at 90 degrees from other.

Now as this tool rotates up the hole, these four pads record microresistivity. Then they compare these pads from one, the resistivity, the microresistivity reading from one of these pads to all the other pads and where there's an anomaly, they consider that pad to have some kind of anomaly for the rest of them. That pad's seeing something different in the wellbore, and when you take all four pads in conjunction and look at what each of the pads are reading and interpret these things, we come up with what we consider to be a highly accurate tool to determine where the fractures are located within a wellbore.

We have, the operators within the area have run, at my latest count, fifteen of these logs within the Gavilan Mancos area. I've included four of them on this cross section to show you what they all show to be, and that is that the highly fractured Niobrara interval is concentrated within the A and the B Zones.

Now I mentioned that when there's a resistivity, microresistivity anomaly, if we could refer to the well on the far lefthand of the cross section, the Lindrith B No. 74, each of the four pads are represented by the four lines that run diagonally up the log. The computer keeps track of the orientation of Pad No. 1 at all times in respect to magnetic north, and in this respect you can then back calculate the orientation of any of the other three pads.

Pad No. 3, which is diametrically opposed to Pad No. 1, would be 180 degrees magnetically north away from Pad 1. Likewise Pad 2 and Pad 4 are 90 degrees in their respective direction away from Pad 1.

Within this green interval on Lindrith B No. 74, Mr. Chairman, you can see that some of these pads, the traces are expanded out. This is a Schlumberger presentation of this frac log and what they do is they take the microresistivity of all four pads and add them together and then on each of the pads they take -- such as Pad No. 1, they take its microresistivity values and overlay that on the average resistivity value of all four pads, and if there is a difference, then there is a separation on the curve, which is Pad No. 1.

Likewise they do this for Pad No. 2 compared to all four pads average resistivity values; Pad No.

3 and Pad No. 4, and we see here that up and down this log that until you get within the area that I've highlighted green for you, that there really isn't much or any separation between these values, and this is generally interpreted to be the highly fractured interval within that well.

The next well, the Bearcat, is also a Schlumberger presentation. It would be the same as in the Lindrith B-74 and again if you were to look up and down the hole, at the sections of the hole I've shown on this log, you would see that within this green interval is considered the area of intense fracturing.

Now the far right two cross sections are -- their presentation is a little different. That's because it's a Welex log run. They do the same -- they use the same type tool and the same type technology but they use a different software package to -- to read the -- or to display the data on the actual paper log that we receive.

Instead of comparing all four microresistivity averages to one pad, the Welex log takes Pad 1 and it compares its resistivity, microresistivity reading to Pad 2. Then it compares Pad 2's microresistivity reading to Pad 3, and then it compares Pad 3's microresistivity reading to Pad 4 and again Pad 4's microresistivity reading to Pad 1, and where there is separation or disagreement within the microresistivity readings of these pads, they are highlighted and shown up on the log.

Again I'd like ot refer you to the well, the Canada Ojitos Unit 33. If you were to look up and down the section of log that I have on the cross section, you would see that only within the highlighted green interval of the A and the B Zone do we have any large, continuous evidence of fracturing.

And finally, on the Canada Ojitos Unit No. 32 we also see that the area of fracturing, the intense fracturing, is confined to the area in the A and the B Zones.

Q On this cross section, Exhibit Six, that you've just described as showing the interval of intense fracturing, is it reasonable for us to conclude that there is variability within the fracture components within the Gavilan Mancos Pool porosity systems?

A Yes, I think there is. The fracture log cannot differentiate from one well to the other how many fractures are in the wellbore or to their permeability or anything of that nature, but it can tell you the thickness or the height of this fractured interval, and looking at the cross section, you can see that from one well to the other that there is a great difference in the height of this intense fractured interval that is communicated up and down this fractured interval, so there is variability.

Q And what is your evidence for this besides what you just stated and in this connection I refer you to what's been marked Exhibit Seven and would ask you to explain it.

A Exhibit Number Seven is a collection of articles that I thought might be informative, Mr. Chairman, as to reservoir variability within a fractured reservoir.

We mentioned earlier that we had a two porosity system. What I would like to address now is the fracture component of this dual porosity system.

The first article, and I've Xeroxed the cover of the guide book that this article came from, which is in the New Mexico Geological Society San Juan Basin III guide book in 1977.

There's an article in there entitled Fracture Permeability in Cretaceous Rocks on the San Juan Basin. The authors were Frank Gorham, Lee Woodward, Mr. Callender, and Mr. Greer.

I've highlighted in their introduction what I think are the important facts. In this article they state that "open fractures tend to develop where tensional joints form at places of maximum curvature of beds; i.e., where there is a greatest rate of change or dip, not necessarily where the dips are the steepest."

Also I've highlighted one other little

passage stating that "Bedding thickness influences competence; Harris and others (1960) suggested that density of joints is greater in thin beds" than in thick beds.

Again, on the next page, in their conclusions, I've highlighted what I think are pertinent passages to this testimony.

The first highlighted passage is that field studies of joints when we refer to the joints or fractures interchangeably in publications, by Harris and others in 1960 and by Stearns and Friedman in 1972, have shown that the density and orientation of joints in the folded beds are directly related to where they occur on the fold.

If I could refer you to the next article in the handout, this is a partial copy of the article, original article that this first publication referenced several times by Mr. Harris and others in 1960. This article was originally a thesis by Mr. Harris and whenever he went into industry and when industry allowed him to release this thesis seven years later, he was able to have this article published in the Bulletin of the American Association of Petroleum Geologists, which occurred, then, in December of 1960.

The title of his article is <u>Relation of Deformational Fractures in Sedimentary Rocks to Regional and Local Structures.</u>

If I could have you refer to the next

page in the exhibit, this is a map of what he has entitled -- what Mr. Harris has entitled the "Iso-fracture Map of the Goose Egg Dome", located in Natrona County, Wyoming.

The reason I included that in there was Mr. Harris went around this dome and field mapped and measured the orientation and fracture density of all the fractures within this area.

Now he has a technique where he measures every fracture in every bed and then since different beds have different levels of confidence and different thicknesses, they're going to fracture differently, yet what he does is he relates this back to what he refers to as a reference or a datum bed and the calculates the amount of fracture that would be in any particular area of this datum bed.

What he's done here is contoured up the amount of fractures occurring per square yard on this dome and if we were to quickly glance at some of the data points, the numbers above little squares is the amount of fractures that he mapped within each square yard. We see that closer to the center of the dome we have 1-1/2, 2 fractures per square yard.

In another area to the south they increase to areas where there are 3-1/2 fractures per yard.

And then to the north, on the northern portion of this dome we see several different contour intervals ranging from -- I don't know what his contour interval is, although I think he has a key at the base of the map here, but we can see that in some areas there are greater than 9 fractures per square yard, yet they quickly fall off on either side to 7, 6, 4, and then back down to 1 to 1-1/2 fractures per yard. This shows that within any structure there's a great variability into the amount and density of these fractures in any one particular area.

Referring you to the next page of this exhibit is another page Xeroxed from his article and here he did the same type of field mapping of the fractures within a large area of the Sheep Mountain Anticline in Wyoming, and again contoured up an Iso-fracture map, and I've highlighted the part that I think is significant here on this page, and again he stresses that one iso-fracture map of the Goose Egg Dome, which is -- shows local fracturing due to a local structure, and then the second map, which is the Sheep Mountain Anticline, which is the regional fractures, that in both cases the fractures, their orientation and their densities are directly related to where they occur on the structure and that different portions of the structure are going to have the greater concentrations of fractures. This is directly related to areas of maximum curvature of the beds, meaning either areas where the rate of change of dip is the greatest or -- and/or the area of the greatest rate of change of strike is the greatest.

Again the next page of his article is -- I won't read the whole thing, it's highlighted here -- but again his conclusions are that where there's areas where there's maximum curvature of the bed, where there's the greatest rate of change of dip and/or strike is where you have the potential for greater fracturing to occur. Where you have greater potential for fracturing you have -- you have the potential for more fracture to occur at any particular unit of rock as in offsetting pieces of rock.

I'd like to refer you to the next page and in here I would like to explain what this is. This is a Xerox of a publication that I got the next article.

The American Association of Petroleum Geologists has a habit of taking out certain what they consider landmarks of very constructive articles that get published repeatedly in their journal, or their bulletin, their monthly bulletin, and they group these into different categories so other people can read, assimilate, and learn and hopefully use to find more oil.

And this next article was reprinted in the AAPG Reprint Series No. 21, entitled Fracture-Controlled Production.

We would turn to that article. It was originally published in the AAPG in 1968 by George Murray.

This title of this article is Quantitative Fracture Study of the Sanish Pool, McKenzie County, North Dakota.

We turn to the second page of this article. I've highlighted what Mr. Murray did. What he attempted to do was to make a second derivative calculation and I would like to stop here and say that a second derivative is he's measuring the rate of change of strike -- of dip on a particular reservoir bed. We can think of rate of change as more like acceleration. It's where things are occurring faster than in others.

What Mr. Murray did was -- is shown on the next page where there's a map of the Antelope Sanish Pool. Mr. Murray took cross sections down from the -- down dip on this dome and there's -- what he did then was take the second -- he assumed that the cross section was the curve representing the dip of the bed and he did the mathematical calculation of a second derivative and this second derivative is the areas where the dip changes most quickly. It doesn't -- it's not the steepest -- steepest part of the dip. The steepest part of the dip does not really change necessarily, but it's where these this dip comes from either very steep dip into a shallow dip or vice versa, and then he contoured up these areas and he had two particular areas. One was on the positive curvature at the top of this anticline and one was at the bottom of the bottom of the curvature at the base of this anticline.

He then related the areas where he considered to be the highest second derivative of the maximum rate of change of dip and related where the best producing wells, and in most cases where the only producing wells in the Sanish Field were confined and this is within the general area of the highest second derivative on this particular map.

I might point out that what he did was he only did one component of rate of change and that was the rate of change in dip down structure. He has not taken into account the rate of change of strike of the bed as it goes around any particular structure.

And lastly of the articles, I'd like to refer you to an article that was interviewing, again, Mr. John Harris, who wrote the first article I referenced from the AAPG, and this report occurred in the Drillbit Magazine in May of 1982.

And in this he stressed that "areas of maximum curvature are areas where there is a maximum rate of change in dip or strike and that that key is the rate of change." You can see this maximum curvature either by field mapping on the surface or by doing a second derivative map of the surface of the reservoir and when done properly, both of these maps can be overlaid and you can see where the greatest concentration of fractures are more likely to occur ina particular fractured reservoir.

The last two pages I have a little show of method of calculating a second derivative on a structure.

There are four, four steps and what I've highlighted here in yellow is a square mile and first what you do is you grid -- grid your structure map and determine the data at each of these grid points, and in this particular case, this example, they are half mile grid points.

Then you add up all nine of this grid datum values and divide by nine and you get the average value of the structural datum which be there if that plane was -- if that surface was a plane within that center datum.

Then you subtract the average datum of that central point from the actual datum value to get your amount of structural departure. This then, when you contour it up, will give you a second derivative map and this will show you where either you have the greatest rate of change of dip and/or the greatest rate of change of structure.

These areas are areas where the rocks have been subjected to more deformational curvature. Rocks should then be fractured more and you would have then more fractures per unit of rock in that area than in areas where there is not much structural departure.

Q Have you constructed a second derivative map for the Gavilan Mancos Pool, and in this connection I'd like for you to refer to what's been marked as Exhibit Eight.

We're going to put Exhibit Eight up, I think up behind you, Alan.

A Thank you. Exhibit Number Eight is my second derivative map that I constructed within the area of the Gavilan Mancos Pool area and the West Puerto Chiquito Pool area. This is the same -- the datum that I used was the top of the Niobrara A Zone, in fact the structure map that is marked as Exhibit Number Two.

I took a grid of a half mile sections on each of map and determined the value, structural datum value of that grid. This method I have described in the last exhibit.

After calculating a second derivative, I contoured up areas of equal structural curvature. We have negative structural curvature and positive structural curvature. I've highlighted them separately on the map and these two colors have nothing in relation to the colors of any of my other exhibits; it's just that my draftsman got a better price for red and green and bought them by the bulk.

So we do have red and green on this map.

In the article I referred to by George

Murray, he talked about negative and positive curvature in his article of the second derivative. The value of the sign, negative or positive, doesn't really matter because in each cases it just relates the structural curvature difference or deviation from the average datum of the rock on that plane. In either case the rocks have been thrown into deformation from the fractures. but what I've attempted to do with the red and the green here is highlight the areas of negative or positive structural curvature and -- or structural departure.

The dotted line represents zero value where there was no structural departure.

The green and the red are both highlighted in varying colors to show the intensity of the deviation from the datum plane as to how much deformational forces the rock was subjected to.

I think there's a -- when you get the map colored up. I think there's two very definable structural entities that are brought out, not only on the structure map, but on the second derivative map, and if you'll notice in the major portion of 1 West that you see that the curvature, the structural curvature departure is coming in a north/south direction and that reflects the monoclinal axis there of the monocline that is producing within the West Puerto Chiquito Pool; however, as you come into the syncline, you get into a general area where there is not much structural departure, and as you get to the west and go over the Gavilan Dome area into Gavilan Mancos Pool interval, you can see that the direction and change of the structural departure is oriented in a general northwest/southeast direction, so it occurs in several different orientations.

I think a big reason for this is that if you look in the West Puerto Chiquito area, you're dealing with one component deformation. You're dealing with a great rate of change of dip, structural dip, not so much strike, because the -- that monocline runs -- trends basically north/south; there's not much change in strike. Strictly for the most of it, it dips; however, when you get onto the -- the Gavilan Dome, you can see that more easily on the uncolored structure map over here, that the strike of the beds curve around that dome and there's areas where there's a great amount of structural curvature due to strike; also of dip.

I'd like to refer you back to Exhibit Number Three, which was my structural cross section. I had said the big structural cross section was a general cross section that just showed structural relation between individual wells.

I've included on the upper lefthand corner of that map a structural profile, a direct line from

Point A to Point B, I mean line A to A', which is the same general cross section of the larger cross section, but that is the structural profile. I've given it some vertical exaggeration just to show that there is differences in the change -- or in the amount of dip over the area and that the dome is not dipping at .6 degrees.

It averages .6 degrees, but there is areas where there is a little bit of change in this dip; therefore, an area where there's the greatest rate of this change, a second derivative is going to get more fractures; likewise, in conjunction with the change of the strike as you go around this dome, you also get a rate of change when you construct a second derivative map of the top of the Niobrara A Zone in Exhibit Number Seven -- Eight, excuse me, Exhibit Number Eight. You see that there are two separate (unclear.)

I would like to now put an overlay on there showing what we have proposed as the Gavilan Mancos Pool boundary.

Mr. Chairman, I hope you'll be able to see this through the overlay, but this is the proposed Gavilan Mancos Pool boundary that I have outlined on the structure map and again a point of reference as to where the second derivative map would fall in relation to this proposed pool boundary.

I've got one last thing to say about my second derivative map, is that it would be nice if you could correlate the greatest, the highest values of either positive or negative second departure on my map and drill a well there and get the best well in the field, and I'm sure some people are going to take my map and go out there and get their location to do that, but they may or may not get their results that they want. They may be disappointed because this structural curvature this rate of change of strike or dip, is not the only component, or is not the only component that affects the amount of fracturing and/or the productivity or reserves of any particular well. That's only one component. It's just to show that there is variability within the area and that there's no way if you were to say that this structural curvature map represented exactly where the concentration of fractures were, and if you wanted to expound and postulate that that would be where the oil was, and so therefore there's a certain amount of oil here, there's a certain amount of oil over there, it can't be done. There's other factors that are involved in a fractured reservoir.

Q In summary, then, would you say that the second derivative map shows that the fracture component of the Gavilan Mancos reservoir is not uniform throughout the field?

A Yes, I would say that's highly true.

Q And that it is hard to interpret how much oil is in any one particular area or one part of the field?

A Very hard. It just relates to the amount of deformation that particular -- the rock was exposed to in any particular area.

Q And I want to make sure that I understood one of your last points, even though you would -- the second derivative map might indicate a position that you would think would be advantageous, are wells in the field sensitive to drilling and completion?

A Yes, they are highly sensitive. The drilling muds can really foul up the fracture system in drilling and a well can lose circulation and depending upon your water loss and your muds and everything else, the Gallup interval, or the Niobrara interval is highly water sensitive.

Also in completion practices things can happen. It's not perfect. You're at the surface and you're sending stuff down to do the work for you at about 7000 feet below the ground, and things do happen. There is -- there is a high degree of variability and therefore, just because, as I said earlier, you drill a well in a particular hot spot, as airbrushed on my second derivative map, you may not be guaranteed the best well in the field.

Q You have talked about the difference between the Gavilan Mancos and the West Puerto Chiquito Mancos Pool. Have you prepared an exhibit that has put these differences in regional perspective, and in this connection I'll refer you to Exhibit Nine.

A Mr. Chairman, I've included in my Exhibit Number Nine a generalized map and cross section, and I do want to refer to it as generalized. This is not -- I have not constructed this to a-- true to scale. It's strictly to show the relationships of the productive intervals of three separate pools and the anticlinal and synclinal flexuring along the eastern boundary of the San Juan Basin.

The map on the lefthand side of this exhibit shows the general or the pool boundaries both proposed for the Gavilan Mancos and the West Puerto Chiquito and East Puerto Chiquito Pools, and I've highlighted what I consider to be the main producing intervals within the Niobrara zone form each of these three separate pools.

From articles and discussions with operators, I've been told that the East Puerto Chiquito Pool is producing predominantly from the A and the B Zone. Likewise, the West Puerto Chiquito Mancos, it is my understanding that the majority of the production comes from the C Zone within this pool and that that's where the pressure maintenance system is occurring.

I'd like to say that in the Gavilan Mancos Pool, from geological study and engineering study, we've determined that the majority of the production within the Gavilan Mancos Pool is coming from the A and the B Zones.

Now if we would refer to the generalized cross section on the righthand portion of the -- of this exhibit, I'd like to first explain that what I'm trying to relate here is if we take the whole Niobrara interval and if we were to cause it to bend around a fold, either the anticlinal fold or a synclinal fold, I'd like to show you thqt the top portion of that interval is going to be subjected to extensional tectonic, extensional pressures, and that the lower portion in an anticlinal flexure is going to be subjected to contractional stresses.

And if we were to take a look at this cross section, in the East Puerto Chiquito Mancos, which is producing on a structural nose, very top of the monocline, we have an anticlinal flexuring and if we were to take the A, B, and the C Zones and bend this around the anticlinal flexuring, we would expect that the A and the B Zones, that these intervals would be exposed to extensional tectonics and that the fractures would -- the extensional fractures would be confined to the A and the B and that the C is going to be, if there's fractures there, is going to tight and be pretty nonproductive.

Likewise, as we go from east to west, we get into the West Puerto Chiquito Mancos. Now that is producing at the base of the monocline. It's not producing within that syncline that I was referring to earlier. At the base of that monocline, that's where the greatest structural curvature is occurring and so the A and the B Zones are going to be contracted and the C Zone of the Niobrara is going to be exposed to the extensional fracturing within the tectonic forces there, and you would expect to get the majority of the production coming out of the C Zone.

Then when we get on the other side of that little syncline that's geologically separating the two areas, we're back into the Gavilan Dome and again the A and the B and the C Zones are being subjected to positve curvature anticlinal flexuring and the A and the B Zones would then be in extension whereas the C Zone would be in contraction there.

Now, we see this. We've determined from production logging and from the frac log that I've shown on one of the exhibits, that the fractures tend to be in the A and the B Zones. We do have some fractures in the C Zone, just like any of the other two pools do but it's -- this relationship of -- of the particular zones, their spatial relationship to the positive or negative curvature of the anticline or the synclinal flexuring, that give the differences between these three adjacent pools, why one is adjacent and has A and B production, why the next one has C production, and why the third one has A and B production, also.

Now, like I said, this is a generalized exhibit. We do have some C production from the Gavilan Mancos Pool. I believe in earier testimony the Canada Ojitos Unit Well that's in Section 30 of 29 North, 1 West, has the production log show that there was production coming from the C. That doesn't surprise me. If we put that into true structural relationship, it's on the west side of our dividing syncline, yet there is a still a minor amount of synclinal flexuring that is exposed, that the Niobrara interval is exposed to; therefore the C Zone would -- there's no problem there in my mind that we would get some production from the C Zone, but there is going to be a minimal amount of slop, I would call it, that we're going to have a little gray area where there's going to be a little of not communication but production from maybe all three of the different intervals, but when you get onto -- if you take the Gavilan Mancos Pool as a whole and put it in its true structural relationship, we see that the majority of the production is coming from the A and the B Zone.

Q Does this conclude your direct testimony?

A Yes, it does.

Q Were Exhibits One through Nine prepared by you or under your supervision?

A Yes, they were.

MR. LOPEZ: Mr. Chairman, at this time I'd like to move the admission of our Exhibits One through Nine.

MR. LEMAY: Without objection Exhibits One through Nine will be admitted as evidence.

Any other direct or friendly examination?

MR. PEARCE: None, Mr. Chairman, thank you.

MR. LEMAY: Any questions for --

MR. KELLAHIN: I have some.

MR. LEMAY: Okay, let's take about a ten or fifteen minute break and we'll come back.

(Thereupon a recess was taken.)

CROSS EXAMINATION

BY MR. CARR:

Q Mr. Emmendorfer, initially I want to be sure I understand some of the things that you, and, I suspect, we can agree on.

First of all, as I understand your testimony, the A Zone, the B Zone, the C Zone, and the Sanostee, you can correlate across the area. You can map them across both present West Puerto Chiquito and the present Gavilan.

A Yes, you could pick those tops.

Q And in your study as you've worked across this area you have found no barrier between the two areas.

A I wouldn't want to say that because I don't know what your definition of a barrier is.

Q Have you found a restriction that would permit or prohibit the flow or oil across any particular area in the combined Gavilan-West Puerto Chiquito area?

A Not using conventional wireline logs.

Q Now, and you found, not having found any of those barriers, do you have anything that would show that we have separate sources of supply?

A Well, now it depends on your definition of separate sources of supply.

Dealing with the Mancos interval this -- you could argue one source of supply of the Mancos for the whole San Juan Basin.

Q I'd like to go to your Exhibit Number Two, which is your cross section, and I would like to find out, first of all, you indicated you had an average dip in the Gavilan area of .6 of a degree.

A That's correct.

Q And have you translated that into a footage figure?

A I can't do that in my head.

Q Would you accept, subject to subsequent correction, that that would work out to approximately 55 feet per mile?

A I think that would be correct, somewhat.

Q Now, the area you've summarized, the area that you looked at to develop this average figure of .6 of a degree, did you include the area that you are proposing be included in the Gavilan?

A Yes, I did.

Q So you included that additional row of sections that is currently in the West Puerto Chiquito Pool?

A Yes, I did.

Q And that is one of the flatter areas in this -- the area that we're talking about in the hearing, the combined pools, is it not?

A Well, it's as flat as the top of the Gavilan Dome is flat.

Q And that would be the other really flat area, isn't that correct?

A Yes, that's correct.

Q So in averaging, in reaching an average, you've used the two areas we're talking about that show the littlest or the least degree of dip.

A Yes, but if you would look at my structure map, you would see that that is not a significant portion of the whole Gavilan Mancos Pool.

Q If we take a look at this map and if we go to the structure map, and we look at the westernmost tier of sections in 25 North, 2 West, have you calculated the amount of dip in, say, Section 36, in that one row of sections?

A Separately?

Q Yes.

A No, I have not.

Q Have you done that for the dip in 31, 25 North, 1 West?

A Separately, no.

Q In Section 32?

A No, I have not. It can be done.

Q Have you calculated section by section as we move across the subject area what the dip would be?

A I took an average throughout the whole area.

Q If we go to your Exhibit Number Four, it was my understanding that you talked, correct me if I'm wrong, about drilling breaks in the mudlogs as being an indication of matrix porosity.

A I don't think I testified to drilling breaks.

Q All right, then that isn't something you're intending to present testimony on?

A We can talk about it, if you would like. Mudloggers do -- do indicate drilling breaks, and a lot of times that is indicative of porosity within a rock unit as you drill through it.

Q And could that also be indicative of fracturing?

A Yes, and no.

Q It could be, could it not?

A Yes, it could.

Q Yes and no? Yes. Now, you had the mudloggers out there and they were looking at the samples that were coming up and if I understood your testimony, they were able to conclude from this that there was matrix porosity, is that correct?

A Well, yes. They take the samples as they come out of the -- out of the flow line and put them under a binocular microscope, it's standard procedure, and look to see if there is porosity, and I've been out on -- in the mudlogging trailer and I have witnessed this myself.

Q And based on the informaton you got from mudloggers, they concluded there was porosity there.

A Yes.

Q And the same information, however, was analyzed by Terra Tek and they could find no matrix contribution. Is that correct?

A Yes. I think they said that there was some but they did not think it was significant.

Q All right, no significant contribution.

A No, not no significant contribution; that there was no significant matrix porosity that they saw.

Q Now, the mudlogger --

A There was a petrograph -- I'd like to say there was a petrographic study as to the amount of matrix porosity, not how much that matrix porosity would produce.

Q Now, Mr. Emmendorfer, the mudlogger takes a look at the samples and looking at these samples I gather from your testimony they concluded there was a high porosity oil cut, looking at the samples themselves.

A I don't understand high porosity oil cut.

Q When they looked at them they concluded there was high porosity in these samples, is that correct?

A No. I believe I testified that if you would look at these sample show sheets that they define what they considered to be the amount of intergranular or interparticle porosity within that sample.

I believe they have only three subdivisions and it's subjective, it's poor, fair, or good porosity development.

Q And did you get that kind of information on the Mallon State -- the Mallon Davis Well?

A Yes, we did.

Q And they did find there was this good development, did they not -- the mudloggers?

A I don't believe it was good, but we could look on the sample show.

Q How did they characterize it?

A Let me look in the exhibit, please. Which of the two sample shows are you referring to?

Q I guess it's the last page. It's got Show No. 9 on it at the top. How did they characterize the porosity in that well?

A Fairly well developed, intergranular porosity.

Q Okay, then did you receive a core on that interval?

A Yes, we cored that interval.

Q And did the core -- the core did not confirm the mudlogger's information on the porosity, did it?

A Not as described by Terra Tek.

Q I think I'd like to go for a minute to what I believe is your -- is this Exhibit Number Eight? I think you're holding up Seven.

A No, that's Eight. This is Seven.

Q Now if I understand the red shaded areas, those are areas where there would be -- the darker the red, the greatest curvature. Is that -- is that what this is designed to show?

A The greater the negatiave curve -- or negative structural departure from a plane, yes.

Q So the darker the red, the more flex, I guess, in the formation?

A Potential for it, yes.

Q And in those areas you'd expect to have the greatest amount of fracturing, is that not true?

A We would hope so, yes. That's the general idea.

Q Now, in this reservoir, the thing you're attempting when you drill a well to obtain is a -- is to tie into the fracture system, is it not?

A Yes.

Q And if you tie into the fracture system your chances of having a better well are increased. Isn't that correct?

A The greater the intensity of fractures in that fracture system, yes.

Q And in the darker shaded areas we could anticipate a greater intensity of fracturing than in an area that is not shaded.

A We can hope for the possibility of greater fracturing.

Q And if we go through and take a look at the map, there's sort of an area starting in 32, oh, let's see, 25 North, 1 West, and it runs north of that and it's an area that is by and large not shaded, is that correct?

A That is correct.

Q And in that area we have a couple of wells, one in Section 29, one in 32, in areas that are shaded light green and one two-tone green but those are areas that have a limited curvature, isn't that correct?

A Yes, that is correct.

Q And isn't it true that the two wells, the one in Section 29 and the one in 32 are the best producing oil wells in the State of New Mexico?

A I don't know about the whole State of New Mexico.

Q They're extremely good oil wells, are they not?

A Their flow would indicate so, yes.

Q Now, if we go up into Section 22 of 2 West, 26 North, there's an Amoco No. 1 Seifert Gas Com A. That is right in the center of an area that is shaded in dark red, is that not correct?

A That is correct.

Q Are you aware of what kind of producing capability that well has?

A No. I believe Amoco is testing it and that they've been shut down for the most part because of weather.

Q You don't know that that's an extremely poor well?

A I have no idea.

Q There's a well in Section 31 of 25 North, 1 West. It's Unit Well No. 26, I believe. Are you familiar with the producing capabilities of that well?

A Yes, I am.

Q And it's in an area that you've shaded red, is it not?

A Yes, it is.

Q And it's an extremely poor well, is it not?

A I believe that is correct.

Q Now, if I looked at where you've placed the Gavilan Mancos Pool boundary, the proposed pool boundary, and where you've indicated on the east side of that where you're intending to move it, you're in effect moving the eastern boundary of that pool one section to the east, are you not?

A That is correct.

Q And where it's presently located it pretty much traces an area that is lightly shaded, isn't that true?

A That is true.

Q And as you move it over to the west you're actually drawing it through an area that's more darkly shaded, darker shading, isn't that also correct?

A That is correct.

Q And if the darker shading corresponds to increased fracture activity, wouldn't you anticipate more fractures along the curved boundary than along the one that we're currently -- show more fractures along the proposed boundary than along the curved boundary?

A I think what you're doing is missing the point of my exhibit. This is structural -- it's a second derivative map to show that there can be variabilities in the fracture intensity. It doesnt matter if it's a red color or a green color, there are areas that there's structural departure in either way from a datum plane, and that we can't tie, and I've testified that we cannot tie the structural derivative map, the value on this structural derivative map, to the amount of oil in place or to the productivity of any one well. It's strictly to be shown that there's variability within the fracture component of the reservoir.

Q So all this shows is that fractures vary across the pool but that productivity of any well anywhere on this map doesn't necessarily relate to any of the coloring that you've shown on this map. Is that what you just said?

A Yes, I said that.

Q So this doesn't show you where you're going to get a good well or where you're not?

A No, I testified that that wouldn't do that.

Q And it doesn't show you where there's communication across this area, does it?

A No, it's strictly to further illustrate the structural differences between the West Puerto Chiquito Pool on the, say, final flexuring of that monocline and the Gavilan Dome and the syncline that separates the two.

Q Now I'd like to go to Exhibit Number Nine. If I understand Exhibit Number Nine, if we go to the cartoon over on the right --

A Could I get mine, please?

Q Yes, sir. If we go to the cartoon or diagram on the righthand side of this exhibit, if I understand it, you're showing with the red shaded area that area where, correct me if I'm wrong, where you anticipate the production to be coming from the West Puerto Chiquito Mancos Pool.

A That's what I understand, is that the C Zone in the West Puerto Chiquito Mancos Pool, and I've testified to this, that in this schematic cross section, I've identified the predominant producing interval of each of the three pools.

Q All right, and so this is how you are depicting the predominant producing interval in the West Puerto Chiquito.

A That is correct.

Q And yet that is above the portion of that structure where there is a greatest flexure; i.e., down where the letter C actually appears.

A If you want to look at it from a very limited scope, yes, the very base where that C is labeled is that syncline between the two. That is not where the production from the West Puerto Chiquito is coming from. It's coming from the greatest rate of change coming off that steeply dipping monocline. The dip starts to change greatly and that's where the West Puerto Chiquito production is occurring --

Q Okay, if I --

A -- that lower part.

Q If I look at your cartoon, it appears to me the greatest rate of change is below where you've shaded it in red. Wouldn't that be true?

A On a -- on this schematic item, yes, but I testified that it was not accurate to --

Q All right.

A -- true structure.

Q All right. Now I think you testified that the West Puerto Chiquito Mancos Pool was producing from the C Zone, isn't that true?

A That's where the majority of the production is occurring.

Q Are you familiar with the Unit Well L-27, located in Section 27 of Township 26 North, 1 East?

A I heard testimony about that yesterday.

Q And that is producing from the unit, is it not?

A Yes, it is.

Q In the unit area?

A Yes, it is.

Q Are you aware that from the B Zone it has produced almost half as much oil as the total production from the Gavilan?

A No, I'm not. I've never seen a production log on that. It's my understanding that the A, B, and

C Zones are open in that well. All three were stimulated and it's just interpretation as to where that production is coming from. There is no documented proof that that oil is coming from the B Zone.

Q And do you have anything that would prove to you that it is not?

A No, sir.

Q Thank you. That's all I have.

MR. LEMAY: Additional questions? Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Emmendorfer, when we looked at Exhibit Number Eight, I think I understood you to say that in determining a boundary between the two areas of the Mancos reservoir, that you have not, cannot, and will not use this display in the second derivative analysis to determine that boundary.

A No, sir.

Q You can't use it for that purpose, can you?

A No, sir. I strictly put that overlay

with the boundary on there to show, as I have it on the structure map, where the proposed boundary is, just as a matter of reference.

Q When you discussed with Mr. Carr the mudlog and the core information, can you identify for us what well you had when you discussed the mudlog and the core of that well? What well was that?

A Yes. The Mallon Oil Company's Davis Federal 3-15.

Q Am I correct in understanding your direct testimony that you have selected the mudlog position over the core information?

A I'm sorry, I don't believe I understand the question.

Q Having the choice of the two data, the mudlog information and the core information, I believe I understood you to tell me that you would select the mudlog information.

A In -- for what reference purpose?

Q You tell me, with regards to matrix porosity and fractures.

A The core data and mudlog sample shows are different. You can quantify porosity and permeability measurements from the core. It's hard to do from a sample, a drill cutting.

Q So then my basic statement was correct, that you have selected the mudlog information over the core information to make that conclusion.

MR. LOPEZ: Objection, Mr. Chairman. That wasn't what he said.

MR. LEMAY: I'll ask the witness to -- to not be led by the question, Mr. Kellahin, but maybe explain to all of us what -- what he was referring to when he was describing the core information and the mudlog information.

A From the mudlog information we have the drill cuttings from a particular interval within the well that the mudlogger has described as to its lithology and if any porosity is present and if there is any kind of a hydrocarbon show from that -- that sample.

In the core data the -- from we take a core, you can visually describe that core and you can quantify particular measurements as to porosity and permeability.

I don't think I said that I didn't believe there was any matrix porosity absent within that core. I believe I testified that Terra Tek said that from their -- their estimates or their analysis that they did not think that the matrix porosity was producable, that it was -- they did not qualify as to how much it would produce or would not produce.

Q Am I not then correct when I have said that you have taken the mudlog information over the core data in making your opinion with regards to that point?

A No, I don't believe so. I cannot tell you the exact sand lamina from that core that we have from where that sample cutting came from. I do know it was in that interval.

We know that it was coming from the cored interval. The well was conditioned and the mud was circulated out before the core was cut. I can't say, I cannot tell you that that particular sand cutting with the matrix porosity that has been witnessed has come from any particular individual sand lamina on that core that the people at Terra Tek analyzed and said that there was no matrix porosity. I cannot do that, sir.

Q May it be reasonably concluded from your testimony, Mr. Emmendorfer, that this reservoir is multi-directional in its fracture system?

A I did not say that but I believe that the -- the fracture system is multi-directional, if you want me to state my opinion.

Q Yes, sir. We had one of your exhibits that had four or five logs on them and you discussed with us a log that would show directional fracturing?

A That you could determine directions of fracture orientation from that. I did not testify as to the orientation of any fractures that I saw within those fractured intervals.

Q Refresh my memory about what exhibit that was.

A I believe that's Exhibit Number Seven -- Six.

Q Am I correct in understanding that you're not taking the position at this hearing that you took in the August hearing that you could use directional survey fracture orientation logs to determine orientation of fractures?

A That's not part of my testimony but I think, I think that I've studied them and can determine fracture orientation from those logs.

Q Are there any basic fundamental geologic conclusions that you've reached today that are any different from your testimony back in August?

MR. LOPEZ: Mr. Chairman, I'm going to object to the question as being too over-reaching. If Mr. Kellahin has specific instances as to testimony that was given on direct as to different geological opinions as opposed to the August hearing, let him identify them, but just to ask an open ended question outside the scope of direct or not related to anything that's been testified to, I think is much too broad.

MR. KELLAHIN: Mr. Chairman, it's an appropriate question. This witness has laid a foundation and he testified in August. I've been very careful to avoid what Mr. Lopez has been doing and that is testifying for this witness. I don't want to put geologic conclusions in his mouth. I've simply asked him has he changed his mind since August.

MR. LEMAY: I think that line of questioning is all right. If you'd be more specific I think it's more helpful because you're dealing with three new commissioners here who did not hear the previous testimony, so if you could narrow it down a little bit I think it would be most helpful.

Q With regards to the structure of the Mancos reservoir would you --

A Which Mancos reservoir?

Q When I talk about the Mancos reservoir I mean to say from the western boundary of the Gavilan Mancos Pool to the eastern boundary of the West Puerto Chiquito Mancos Pool. That interval, that area, as you've displayed on your structure map. Have you changed your structural opinions and interpretations from the August hearing to now?

A No, I have not. I've changed my structure map because there's been a few wells drilled since then along that general area; gave me more datum points, so my structure map changed a little bit.

Q Thank you.

MR. LEMAY: Thank you, Mr. Kellahin.

Any additional questions of the witness? Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Emmendorfer, on your Exhibit Number Seven we have a paper written by Mr. Gorham, Woodward, Callender, and Greer.

On the first page of the introduction you've highlighted an area but just before that highlighted area the authors state that the principal factors in the development of fracture permeability, such as radius of curvature, and so on, can you look at the radius of curvature for the what you've called the Gavilan Dome?

A In a general respect, yes. I did not do a radius of curvature analysis as is referred to by the third article in my booklet that Mr. Murray did in the Sanish Pool in North Dakota. I did not do that exact type of calculation, no.

Q What type of calculation did you do on radius of drainage?

A I did not do a calculation.

Q The next item that that paper talks about of development in fracture permeability is rock type. Did you do a study of the rock types associated within the area of discussion in the Gavilan and West Puerto Chiquito Mancos?

A I'm sorry, are we still talking about the --

Q Same article.

A Okay.

Q The next item after radius of curvature.

A Could you repeat that, please?

Q Did you do a study of rock types in the -- or look at the rock types in the Gavilan area?

A I've looked at the two cores in the area, the Mallon core and the Mobil core, and notice that -- and witnessed that there were indeed interbedded sandstones and shales and that the sands tend to be concentrated in the A and the B Zones, which I had already suspected from drill cuttings of logs that had been drilled before that.

Q Another item that's called a principal factor in development of fracture permeability is rate of strain. Did you make a study of the rate of strain on the rocks in these pools?

A No, sir, I did not.

Q Mr. Emmendorfer, on your Exhibit Number

Nine, the top right, you show some interpretations, representations, of positive curvature, negative curvature, and another positive curvature, illustrate the increase in fracture with -- let me ask a question this way.

Is this to illustrate the increase of fracture width the further away from the central point of the radius?

A No, sir, it is not. This again is a schematic diagram. I just used a standard curvature radius of these three -- for these three separate pools.

As a matter of fact, that was a -- I used a figure out of Murray's Sanish Pool study that did do the radius of curvature study. I just used it as a -- as a schematic showing the difference of the rate, not the amount of radius of curvature. I just used the same one as a point of reference. There is a difference in radius of curvature. The West Puerto Chiquito has a much larger radius of curvature than the other two pools would have.

Q Do the three illustrations at the top right of exhibit Nine indicate that the further from the center point of a circle you are on the radius the wider the fracture or opening would be at the same angle?

A That is correct, yes, but, like I said, I have not attempted to show that on my exhibit.

Q Is it your opinion that the radius of

curvature for the -- the Gavilan Dome, just from what you understand of it at this time, is such that there would be significant difference in fractures in the A, B, and C Zones at the -- at that particular distance out on the radius line?

A I'm sorry, if we had the same radius of curvature in the Gavilan Dome as we have in the West Puerto Chiquito?

Q No, sir. Well, I'll go on to something else.

The logical conclusion it would seem like from your Exhbiit Nine is that the shallower the well would be out of the Gavilan area the more likely there would be larger fractures, is that a logical conclusion, would you say?

A The shallower the well would be?

Q Yes, a logical conclusion would be the fractures would continue to extend upwards from the radius and therefore would be also exhibited at the surface or in shallower wells such as Pictured Cliffs or other zones?

A No, you cannot conclude that. I do not hold that one fracture would extend from grassroots to granite. Normally the structural pressures that are incurred on a rock unit, which is a stratigraphic column, will be the same up and down the stratigraphic column, but certain formations do not behave in a brittle manner. They are interbedded with more plastic formations.

These formations may not be subjected or subject to as much fracturing or even any fracturing as the more brittle, competent layers may be, so you do get a fracture, the same fractural orientation if it's created -- if that fractural orientation of a -- of a -- you're talking about a zone, vertical zone up and down all the formations, but that fracture orientation, those formations were subjected to the same tectonic forces, then those fractures should be genetically related in that their direction and intensity -- directions should be -- should be similar.

Q So then the plasticity and the brittleness of the formations are important in this -- in your actual interpretation of whether there will actually be fractures there or not, is that correct?

A Very important. It's the rocks that are able to do the fracturing will be fractured if the tectonic forces are sufficient enough to fracture.

Q Did you make any calculations or study of tectonic forces and the rock lithologies in this area?

A No, sir, I have not.

Q In Exhibit Number Seven, the second article, Bulletin of the AAPG, in the summary, the first paragraph, if I could, says this investigation has shown that in order to use fractures as a tool for interpreting fold structure, it is first necessay to establish the relations between the lithologic and physical characteristics of rocks and their expression of fractures.

A Yes, sir. This investigation, I think, is the key word. If we could thumb back to the first, Mr. Chairman, the first diagram or map, the one that depicts the Iso-fracture of the Goose Egg Dome, I testified that Mr. Harris walked over the surface of the map, the concentration and orientation of these fractures (sic). Now this is from different beds and because normally when you have a structure, one particular formation is not exposed all the way around that -- that structure. There is usually erosion occurring at the surface and one bed may be preferentially exposed to another because of differences in weathering.

He, what he did was he had to take these -- his data points from different portions of the field, different rocks, different formations, different rocks within the formations, different thickesses of the beds, and he made a -- he made a table showing which, which rocks were more susceptible to fracturing because of either their rock streaks, their composition, or their thickness or thinness related to the other ones, and then he used those calculations to arrive from the amount of fractures that was in one particular spot on the surface to a datum -- datum plane --

surface within -- on that area. It's the same thing as making a form line contour map on an aerial photograph. You've got -- you take strikes and dips over many different formations and you relate that to one datum.

Q Mr. Emmendorfer, in predicting the existence of fracturing, would it be important to know past geologic history of the area as to whether or not there had been previous folding, faulting, or other structures that existed during the creation of an area?

A It would be nice to know that, yes, it would.

Q Had there been previous folding and faulting in this area, could that account for fractures existing in areas where this type of prediction models does not show them?

A Normally, unless the rock is very young in geological age, it's subjected to one, at least one or many times more tectonic forces. We can't very easily go back and model each particular one. I'm sure that if you had the capabilities of a large geological-engineering staff that could postulate on this , you could come up with some kind of a study; however, the usefulness of the second derivative map is to show the structural departure that is presently occurring in -- with the reservoir, the bed that you've mapped, and are of interest in.

This would not discuss any type of fracture orientation that would occur, strictly where the rocks are in the latest deformational mode.

Q Thank you.

MR. LEMAY: Additional questions?

Yes, sir.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Emmendorfer, yesterday I questioned Mr. Ellis regarding porosity determination in the -- in the area under consideration at the present time.

He stated that he found that porosity logs were not exactly tools utilized in determining porosity in this area.

Would you concur with that?

A No. I think they're effective tools if you relate those back to actual core data and get your sand -- I mean, excuse me, your shale corrections and all that from your core using sonic logs and that you could then back into a more meaningful porosity determination.

Used just blindly going in there and doing it, I don't think that they're representative.

Q When you say blindly going in there, what do you mean by that?

A Well, normally you just take -- you can read the porosity off of a density log. That does not take into account shale correction, the amount of shale that is in any particular rock, and many articles on log interpretation tell you that this drastically affects the amount of porosity that can be read in a rock.

Q I would agree. Have you done a thorough analysis of the porosities on available logs, making the proper shale correction for the area of concern?

A No, I have not, myself.

Q Are you aware of any data that may be available where that -- where that had been done?

A I believe in the last hearing Mobil presented an exhibit. I --

Q Then perhaps there will be something forthcoming.

The cores that were cut, there are two wells that are cored, is that correct?

A Two wells that have been cored extensively in the Niobrara. I should state there is a third, one 60-foot core that -- in one of the other Mallon wells that has been cut, but I chose the one that showed the greatest amount of section that was cored.

Unfortunately in both of them we missed the majority of the A Zone.

Q I see. Do you know were those cores analyzed in a standard way, if a foot by foot determination of porosity and permeability, water saturation, oil saturation, a study of that nature was performed?

A I don't like to defer questions to the next witness and I know he doesn't like me to do that either, but he has been involved with studies of both of those cores and I think he would be better to answer that question.

Q Thank you, that's all I have.

QUESTIONS BY MR. LEMAY:

Q I have a couple of questions maybe of clarification.

Mr. Emmendorfer, you -- on your Exhibit Number Three, how did you decide where the matrix production was coming from?

A How did they -- the Gavilan Mancos wells?

Q Yes. You have your A, B, and C Zone and I think you testified that the matrix production was coming from the zones as depicted up there. I just wondered how you made that -- whether the wells were perforated or --

A No, it has to do with the combination of, well, my geologic studies using the frac logs throughout the pool, and then the production logs that I've seen and the discussions I've had with our reservoir engineer as to our thinking on the area.

Q One other question. Have you been out on any of the wells in the Gavilan Field when they've drilled to the pay?

A Yes, sir.

Q Have you noted anything called by BPB, the bite, torque, and bounce? Is that a familiar term up there?

A It may be but not in the circle of friends I run with.

Q It's not an X-rated term, either.

Generally, an indirect measurement of fracturing is when the Kelly will jump going into a fractured zone and it will --

A Yes, sir.

Q -- hang up and then torque up.

A Uh-huh, that's correct.

Q The torque is an indication and sometimes mudloggers will note this on the mudlog. I didn't see any notation on the mudlogs you've shown or no testimony today concerning this particular thing as an indirect measurement or really a direct measurement of fracturing.

A Well, sir, we do keep track of that. We -- usually the company man, which is being the engineer, he will make instructions to the drillers and if he's on their good side, they will record for him and tell him where these areas where the Kelly and the drilling floor are just bouncing around.

Usually if the mudloggers are in good speaking terms with the drillers they will tell them this, and we do have -- I do have mudlogs, not with me, that do have the notation "rough drilling", and in answer to your question, I've been out there during the drilling through the Gallup and I have seen the phenomenon your talking about that's indicative of fractures.

Q It is present out in that field, then, as an indiction of fracturing, isn't that true, but not as a correlative tool? People haven't used it out there?

A Well, we try to use every available tool that we can use. I don't think that it's out there as refined to a very fine recording -- recorded value from well to well or anything like that. Each company has their own techniques and they like to use to determine the pay in an area, but I guess that we try to have the drillers tell us the zones that -- that they experience rough drilling.

Likewise, I like to use the geolograph. I think that picks that up rather well. I usually -- I try to take a copy of the geolograph from the top to bottom if they'll let me have one and take it back to my office and you can see very well on there the correlation between where the driller wrote -- or noted "rough drilling" and the geolograph, the weight of the drill string on the geolograph, and a lot of times that's where the driller will record this, is on the geolograph itself.

MR. LEMAY: That's all the questions I have.

Additional questions of the witness? If there are no more, he may be excused.

MR. PEARCE: At this time, Mr. Chairman, I would like to call Mr. Faulhaber to the witness stand.

He has been previously sworn in this matter.

JOHN J. FAULHABER,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. PEARCE:

Q For the record, sir, would you please state your full name, your employer, and your responsibilities?

A My name is John J. Faulhaber. I'm employed by Mobil Producing Texas and New Mexico, Inc.

I'm a Senior Production Geologist responsible for all aspects of production geology in the San Juan Basin.

In addition, I'm the Reservoir Management Team Coordinator with the Lindrith B Unit. The Lindrith B Unit is a 26,000-acre exploration unit. The northeastern corner of the Lindrith B Unit lies within the southwestern corner of the Gavilan Mancos Pool. As such, I'm responsible for coordinating geologic, reservoir engineering, production engineering, and operations engineering for the Lindrith B Unit to insure that it's developed and produced as efficiently as possible.

Q All right, sir, would you please tell us your educational background beginning with your Bachelor's degree, please?

A I received a Bachelor of Science degree in geology with honors from the University of Oregon in Eugene, Oregon, in 1975.

I received a Master of Science degree in geology, also from the University of Oregon, in 1977.

Q All right, would you please outline your employment history in the oil and gas area?

A I was employed as a summer hired geologist for Mobil in Denver in 1975.

In 1977 - 1980 I was employed by Exxon as a geologist, and in 1980 to the present I was employed -- I've been employed by Mobil as a geologist.

Q Mr. Faulhaber, have you testified before the New Mexico Oil Conservation Division or Commission previously?

A Yes, I have.

Q And have your qualifications as an expert in petroleum geology been accepted and made a matter of record?

A Yes, they have.

MR. PEARCE: Mr. Chairman, at this time I would tender this witness as an expert in the field of petroleum geology.

MR. LEMAY: Mr. Faulhaber's qualifications are acceptable.

Q Okay. Mr. Faulhaber, at this time would you briefly outline for us the purpose of your testimony this morning?

A With my testimony this morning I would like to demonstrate for the Commission what the reservoir looks like. I want to show the Commission the fracture system as it exists in the borehole.

I also want to show the Commission what the secondary porosity system looks like in the rocks. That porosity system, tha secondary porosity system consisting of a complex interrelationship of microfractures, intergranular fractures, intergranular sheet pores, and traditional intergranular porosity.

Q Okay, what tool did you use to study the fracture system as you've briefly described it?

A I've used Mobil's borehole televiewer.

Q Could you tell us about that, that device, please?

A The borehole televiewer is a logging tool developed by Mobil in the mid-1960's for the purpose of identifying and evaluating naturally fractured reservoirs. The logging tool takes an oriented, acoustic picture of the inside of the wellbore in the form of a continuous well log. The result is a presentation of the wellbore while -- as if it were split vertically along magnetic north and laid out flat.

Q Okay, I would ask you at this time, if you would, please, to refer to the first page of what we've marked as Exhibit Number One, and Exhibit Number One is the entire booklet, Mr. Chairman. We'll be referring to separate parts of that during the course of this examination. This is labeled Figure 1 and could you describe what's reflected there for us, please?

A Figure One is a simplified schematic of the basic elements of the borehole televiewer. This is excerpted from an article written by the -- one of the inventors of the televiewer for Mobil, Dr. Joe Zemanek.

Q Could you describe how this works, please?

A Okay. The key element of the televiewer is labeled on this diagram as a (unclear) electric transducer. This transducer emits high frequency sound pulses at a rate of approximately 2000 pulses per second. The sound frequency it emits at about two megahertz. This frequency is designed to penetrate mud and normal mud cake within the borehole and obtain a reflection reading from the borehole wall.

This transducer, as it is pulsing at 2000 times per second rotates at 6 times per second and while all this is going on the tool is being pulled up the hole at a rate of approximately 8 feet per minute.

The net result is that a sound pulse is reflected off of the borehole at a rate of approximately -- with a horizontal frequency of approximately one pulse per degree and at a vertical frequency of approximately 45 readings, if you will, per vertical foot.

The character of these reflections, their strength, are then used to provide an image of the condition of the borehole wall. The return signal is converted to a visual image up hole on light sensitive paper and, as I said originally, that image is -- presents the borehole wall as if you were on the inside and had split it vertically along magnetic north and laid it out flat.

Q Okay, when you say that the signal is reflected on the light sensitive paper, what are the characteristics of markings on that paper once this reading is made?

A Okay. A strong reflection comes back and shows up on the light sensitive paper as light, as white. If the signal is -- return signal is weak, such as if you have some roughness or eccentricity in the borehole, then it will show up as black and if the signal is of intermediate strength, it will show up as some shade of gray.

Q All right, at this time, sir, I would ask you to turn the page and look at what has been marked as Figures 2 and 3 and could you describe for us, please, what's reflected in those two pictures?

A Figures 2 and 3 are isometric drawings and corresponding borehole televiewer log depictions of what a planar feature, such as a planar natural fracture, would look like in both the borehole and a corresponding borehole telelviewer log.

Figure Number 2 shows a moderately dipping planar feature and I'll just call them fractures, since that' what we're talking about here today, and Figure Number 3 shows a steeply dipping fracture.

Q Excuse me, if I understand it, if you cut the column figure open and lay it out flat, you develop the curves reflected in the rectangular blocks, is that right?

A That's correct. The inter -- the plane as it intersects the televiewer -- the borehole and if you lay it out flat, it defines a sine wave.

Q All right, sir. All right. Now I notice, sir, that these two figures, 2 and 3, are similar; however, there are some differences. Could you indicate again -- what -- why the difference in shape or slope of those sine curves results?

A Okay, the difference in the sine curves is due to the difference in dip of the fracture. A moderately dipping fracture has a moderate amplitude sine wave, sine curve. A steeply dipping fracture has a high amplitude sine curve.

You can determine the direction of dip of the feature by noting the orientation of the lowest point of the sine curve. The strike direction would then be normal to that.

I'd also like to point out an orientation convention that we have on the televiewer. If you'll look, say, at the bottom part of the borehole televiewer presentation in Figure 2, you'll notice that the convention is that north is on the left side of the image and then we rotate, as we rotate through the image we go through east, south, west, and north, and back to north on the righthand side of the image.

Q And the tool itself is designed to take into account so that it is aware of what -- of north direction at all times, is that correct?

A Yes, it references itself to a magnetometer.

Q All right, sir. At this time I'd like for you to look at the bottom portion of that page, Figure 4, and could you describe for the Commission and those in attendance what's reflected by that figure.

A Figure 4 represents what an induced fracture typically looks like in a borehole. An induced fracture is usually a single planar fracture bisecting the borehole and entering and exiting the borehole at a moderate dip angle.

Q And when you say induced, how are those fractures generally induced?

A Generally in the drilling process due to perhaps excessive mud weight.

Q Thank you, sir. At this time I would ask you to refer to what we've -- to the materials in the pockets --

A Okay.

Q -- of the exhibit packet and you'll probably want to take a few minutes to --

A Yeah, we need to hang --

Q It will just take a moment.

Mr. Faulhaber, we've displayed on the wall and contained in each of the exhibit packets we've passed out, are two sets of two long strips of paper. Could you tell us what these are, please?

A These are Xeroxed copies of the borehole televiewer logs run in the Lindrith B Unit No. 73 and No. 74 Wells.

All right, I'm going to use Mr. Emmendorfer's second derivative map for reference.

The B-73 is located in the northeast quarter of Section 6, 24 North, 2 West.

The B-74 is located a couple miles away in the northeast quarter of Section 9, 24 North, 2 West.

These logs represent two runs that overlap slightly at the top and base. The first run on the 73 goes from approximately 6580 to about 6780. The second run goes from 6780 to approximately 6960.

On the B-74 the first run goes from the area 6420 down to about 6658 or 60. The second run goes from 6660 down to about 6880.

I have added some annotation to this to make it much more readable.

On the righthand side is the cable depth as measred when the log was run. We do not have good depth control on this log so that I have correlated it to the gamma ray curve from the density neutron log and that correlated depth is shown on the lefthand track.

Also on this log at the top and base I have oriented the log with respect to the compass directions. These are magnetic compass directions, north, east, south, west, and north, and also I've indicated the subdivisions within the Gallup formation, Gallup A, Gallup B, the base of what I have called the Gallup B Sands, the Gallup C, and the base of what I call the C resistivity high, since those really are not sands.

Q All right, sir. For a reference, would you give us the depths of a couple of the formations that you've annotated on this log, please?

A Okay. On the B-73 for the Gallup, the top of the Gallup A is at 6683 and all depth references I'll make will be to the corrected depth.

The top of the B is at 6746. The base of the B sands is at 6808, right here.

The top of the C is at 6867 and the base of the C resistivity high is at 6950.

On the B-74 the top of the A is at 6616, down probably where you can't see it except on your own exhibit.

The top of the B is at 6676. The base of the B Sands is at 6740.

The top of the C is at 6801 and the base of the C resistivity high is at 6883.

Q Mr. Faulhaber, what's the vertical scale of this display?

A The vertical scale is 8-1/2 inches represents 20 feet. This is --

Q And the -- I'm sorry.

A I wanted to point out, this is considerably expanded over the normal log scales that we -- we see, which are usually on the order of 1 inch equals 20 feet.

Q What's the horizontal scale?

A The horizontal scale is 2 inches represents a full 360-degrees of the borehole.

Q All right, sir, looking at the display for the 73 Well, would you describe what's reflected on that display, please?

A Okay. There are several features on this display. The first I'd like to point out are these horizontal dark bands. You can see several in the interval from

6602 to 6642, keeping in mind that the dark bands that go completely across are depth reference lines. The ones that are not depth reference lines are shale laminations. The shale laminations provide a poor sonic signal return and hence appear dark on the log.

Another feature we see through the top of the 73 is a sine wave shaped dark feature, which we see quite a number of them on the 73 log. Just to reference you, we see one that starts on the left at 6585, rises to 6583 in the east quadrant, drops down to about 6588 in the west quadrant, and rises back to 6585 when we get back to north.

This sine wave shaped feature is the borehole televiewer log presentation of a planar natural fracture intersecting the borehole at an angle of approximately 82 degrees, dipping ot the west and striking north-/south in reference to magnetic north.

Q And I understand that the degree of dip of those fractures can be calculated between the high and low points represented on that sine curve, is that correct?

A Yes.

Q All right, sir.

A If we know the high and low points and the radius of the borehole we can calculate the --

Q Would you describe -- I'm sorry.

A -- depth of that.

Q Would you describe for us, please, why the fractures are visible on this televiewer log?

A The fractures show up on the televiewer log for two reasons. One is if you're drilling well overbalanced, the mud might prop them open. Two, and more commonly, the thinner edges of the fracture during the drilling process where the fracture intersects the borehole, tend to break as a result of the drilling process and little pieces come out and you -- and therefore provide a roughness in the borehole, which did not return the sonic signal well.

Q Is it possible using this tool to measure the width of any of the fractures reflected?

A No, it is not due to two reasons. One is the beam width is -- is actually, you know, has a 1 degree width and because you're seeing the fractures because they have spoiled (sic) that feather edge. You cannot measure anything in the televiewer to determine fracture width.

Q Okay, could you describe what the televiewer log of the 73 indicates?

A Okay. There's a number of noteworthy features on the 73 televiewer.

One is that we see fractures developed above the A Zone and continuing down into the top of the Gallup A.

Those fractures on the televiewer you'll see become much more obvious and easier to spot. You see much more complete sine waves. You see more of them and they also appear to be steeper.

What we are seeing are -- in an increase in fracture intensity starting near the top of the Gallup A and proceeding down through the top of the Gallup B. As we go down through the Gallup B the fractures become less intense but nonetheless present down through the base of the B Sands and further on down into the B, although they're quite weak in this lower interval.

We see no fracturing in the top of the Gallup C. We see a weak fracture development, what I would term weak, in the lower two-thirds of the Gallup C resistivity high.

Q And would you relate the completion of this well to the information reflected on that televiewer log, please?

A Okay. On this well we spent a few extra dollars in order to try to relate the producton of the well to the fracturing we see on the televiewer. We initially completed the C Zone with perforations and a frac job from 6874 -- let's see, which is about here, to about 6926.

We put this well on -- after perfing and fracing we put the well on pump and left it that way for several weeks. It eventually stabilized at a production rate of 10 barrels of oil per day and 33 MCF per day under pump.

We then set a bridge plug at 6850, in here -- I'm sorry, up in here, and stimulated, perfed and stimulated the AB Zone from 6684 -- I'm sorry, yeah 6684 down through 6800.

We swabbed; we left the bridge plug in the hole and we swabbed for half a day and the well began flowing at the rate of 10 barrels of fluid an hour.

The last test we had before we removed the bridge plug was 99 barrels of fluid per day. I believe a little over half of that was oil.

Q All right, sir, could you compare what you have just discussed on the 73 Well with the televiewer log representation on the 74 Well?

A In the 74 you'll notice that these two logs, sets of logs, cover approximately the same stratigraphic interval. One thing that becomes immediately obvious is there are no fractures above the A. In fact, there are no --

Q Let me interrupt you, if I may, --

A Okay.

Q -- for just a minute. Would you locate those two wells again on the second derivative map for me identification?

A Okay. The 73 map, I meant log, I'm sorry, which showed the extensive fracturing, is located in the northeast quarter of Section 6, 24 North, 2 West, adjacent to this second derivative high, if you will, of Mr. Emmendorfer's.

The 74 Well is located here in the north east quarter of Section 9, close to the zero second derivative line on Mr. Emmendorfer's map.

Q I'm sorry, now would you go back and address the 74 more? I apologize for the interruption.

A Okay. On the 74, as I said, we have no fracturing above the A. We don't even have any fracturing in the top of the A until we get most of the way through the A -- well, about halfway through the A.

Q At about what depth does that fracturing begin to appear in that well?

A At about, say, 6655. The fracturing then extends down through the rest of the A into and all the way through the B Sands. And then once we get through the B Sands, we do not see any fracturing below that. There is a few possible fractures in the top of the Gallup C, but I don't feel comfortable with calling them natural fractures.

Q And how was that well completed?

A In the B-74, because we did not see any fracturing in that well we did not complete the C Zone. We did not feel, the way Mobil completes their wells, we do a stage completion. We do the C Zone first and we did not feel that the economics warranted a separate stage completion on the C Zone.

So we then completed the AB Zone form 6620 to 6740. 6620 is about here and 6740 is down here near the based of the B Sands.

We've only recently done that completion. We swabbed the well for five days and it recently started flowing at the rate of 65 barrels of fluid per day on a 20/64ths choke.

Q All right, sir, at this time, if you would, I'd like to refer you to the sheets contained in a packet at the back of Exhibit Number One. Could you describe for us, please, what's reflected on those sheets and how that information was derived?

A These sheets are what we call rose diagrams. They are designed to represent the relative frequency of the fracture orientation in the strike aspect, where we're mapping the strike, where we're indicating the frequency of the strikes of these fractures.

The -- on the B-73 I measured the strike of 272 fractures and entered them into this computer program for plotting. I told the program to plot and determine the frequency of those fractures in 10 degree increments, starting at north so the first increment is for north, 10 degrees east of north, then 10 degrees east of north to 20 degrees east of north, et cetera, and then it essentially counted the number of fractures that are striking in that particular direction and plotted the frequency of that -- of those numbers on this plot, such that the large wing, if you will, going out northeast, north/northeast and south/southeast, represents 154 fractures and then the smaller pie slices represent lesser numbers of fractures.

Q Let's look quickly at the display covering the B-74 Well. That is a reflection of the same sort of information derived in the same way?

A That's correct.

Q Could you tell us what the effects of having these fractures with slightly different orientation is?

A The effect is that the fractures will intersect in the formation. You can see that even though the major fracture set is trending at about north 14 degrees east, there is another minor fracture set trending more north/south and possibly a few other very minor fracture sets trending at similar but close directions, so -- and this, I'd also like to point out that we also see a variability in fracture dip when we make these measurements so that the fractures do intersect in both a horizontal and a vertical sense in the formations.

Q And the effect of having these fractures not being perfectly parallel is this intersection that you --

A Yes.

Q -- mentioned. All right, sir. In these two wells on which you ran the borehole televiewer, do you find evidence of multidirectional fracturing?

A No, I do not.

Q All right, sir, do you have any general comments which you'd like to make with regard to the borehole televiewer results on the 73 and 74 wells?

A A couple of comments. One is that in both of these wells as a comparative study we ran Schlumberger's dipmeter logs and did the fracture finding type orientations that Mr. Emmendorfer referred to. If you will refer to Mr. Emmendorfer's, I guess it's Exhibit Number Seven, his -- Exhibit Six, I'm sorry, you will notice that the lefthand side of that exhibit --

Q Excuse me, let's slow down and let people get it to refer to.

A Okay.

Q Which exhibit is that, Mr. Faulhaber?

A That's Exhibit Number Six.

Q And what -- what does the exhibit look like? We're having trouble finding it.

A It is titled North/South Stratigraphic Cross Section, Intervals of Intense Fracturing.

Q Okay.

A You'll notice on this exhibit --

Q We're still not with you.

A Oh, I'm sorry. I'm sorry.

Q All right, sir.

A Okay. Looking at the lefthand log in this exhibit you'll see that it is one of these dipmeter logs from the Lindrith No. B-74 Well.

If we look at the interval that is indicated as having fractures on this exhibit, we see it extends from approximately 6658 down to about 6744, if I'm reading that correctly.

If we look at the televiewer log we see fracturing from about a little above 6658, about say 6653, or so, down through about 6738 or 40. So there's a very close agreement between the ability of these fracture, the dipmeter fracture type detection logs to detect fractures and what we see in the borehole televiewer.

This -- these results have been confirmed by the other comparative studies that we made in the other wells.

Q All right, sir, any other general comments with regard to these displays?

A One very important observation is that within the AB Zone we see fractures vertically traversing all lithologic units and interconnecting the AB Zone.

Q Would you point that out to us where you see fractures interconnecting the A and B in this well?

A Okay, it's probably best developed on the 73.

Q First of all, what depth is that?

A This boundary is at about 6745. I don't remember my exact notes, but on a log we would see several lithologies here, with this would be sand, shale, sand, shale, and then into a sand again, and we can see that these sine wave shaped fractures did not really pay attention to lithologic boundaries, and we see several fractures that actually crossed the AB boundary.

We see the same thing on the 74 where the fractures simply extend throughout the formation, throughout the AB Zone, and form what we see as a single reservoir unit, which we call the AB.

Now the exact interval that's fractured, it varies between wells, between logs, but essentially we see a single homogeneous in terms of fracturing AB Zone that is communicated, appears to be communicated.

Q All right, sir, do you have any other comments you want to make with regard to Exhibit Number One?

A No, I do not.

Q All right, it will take just one minute to pass out Exhibit Number Two.

All right, Mr. Faulhaber, at this time I would ask you to refer to Mobil Exhibit Number Two. What are we going to do with this exhibit, Mr. Faulhaber?

A With this exhibit we're going to look at the second portion, if you will, of our dual porosity system. We're going to look at the matrix in its broad definition and how it relates to the major fracture system.

Q All right, sir, and when you say "matrix in its broad definiition", could you once again explain to us what you mean by that term?

A By that term I mean that it is a complex interrelationship of microfractures, intergranular fractures, intergranular sheet pores, and traditional intergranular porosity.

Q All right, sir, let's look at Photo No. 1 in this exhibit. Could you tell us what you displayed in this photograph?

A Photo No. 1 is a photograph of the Lindrith B-38 Core, a short portion of it from the B Zone at about 6691.5 feet.

Top is to the left on this photo. Just to show you what's going on, in the bottom third of the photo, if you would refer back and forth between the legend and the photo, you'll see that in the bottom third we are looking at a natural fracture face.

Q All right, let me interrupt for just a minute.

If I turned the exhibit so that the pictures are at the top, that represents the top of the core sample, is that correct?

A That's correct.

Q All right, thank you.

A Okay. Proceeding up through Photo No. 1, we see a light band across the middle of that. That's simply the surface of the core and then the upper half of the surface -- of the photo, rather -- is the slab surface of the core and with a routine core analysis plug location in the middle of that slab surface.

The things that are noteworthy on this photo is the light, light and dark bands that are going vertically in the photo and that is horizontally in the core, the light bands are very fine grained sand lamination, generally less than 1 centimeter thick.

The dark bands are shale laminations, in this case a few millimeters thick, or less. Okay.

Q Please continue.

A On Photo No. 2 we see another piece of core from the Lindrith B-38 in the B Zone. In the lower third of that photo be see a natural fracture face. This is, by the way, these fracture faces I'm showing in the core are the types of fractures that we're seeing on the televiewer.

The slab surface comprises the upper two-thirds of the photo; again another plug location is shown in the upper left of the photo. Here we can see a lower percentage of very fine sand laminations and a higher percentage of shale.

Q Okay, once again for orientation and understanding purposes, if I turn the exhibit so that the top of the core is to the top of the page and the photographs are right side up reflected on the left of both of those photographs is the natural fracture where the core broke away, is that correct?

A That's correct.

Q And that's clear from the weathered nature of that face, is that correct?

A We identify that by the somewhat irregular nature of that face and in the lower photo, specifically, you can see drilling mud that was not cleaned off the -- off that face.

Q All right, sir, anything else you want to discuss with regards to Photographs 1 and 2?

A This would probably be a good time to illustrate the general mechanism that we feel is operating in this reservoir and that is we feel that the secondary porosity system operating in these thin sandstone laminations communicates to these -- to the major fracture face.

Now in both core and televiewer analysis, the fracture spacing between these major fractures appears to be on the order of anywhere from a half inch to four inches and occasionally up to six inches in the horizontal plane.

So we're dealing with planar fractures spaced at a half inch to six inches apart with most of them on the order of, say, two to four inches apart in the A and B Zones.

So in our model what we see is the potential for communication between the porosity in the matrix with these major fracture faces, keeping in mind that any fluids would only have to travel anywhere from one-quarter inch to, say, a maximum of two or three inches in order to reach the major fracture face and be produced.

Q Okay. let's turn now, if you would, please, to the next set of photographs, labeled 3A and B, and would you describe for us, please, what's reflected in those photographs?

A Photos 3A and B are photomicrographs enlarged at about 300 times magnification. The upper -- they both depict the same view. The lower photograph is a plain light photograph. The upper photograph is a UV fluorescence photograph. These -- we had approximately 40 thin sections from the AB Zone impregnated for inspection with an epoxy carrying a dye that is red under visible light and fluoresces orange under ultraviolet light.

This epoxy and its dye, the epoxy invades the pore spaces in the rocks and when it fluoresces it allows us to see the very fine pore spaces and their interconnections much better than we normally would with just a plain light photograph, when we examine the slide under ultraviolet -- reflected ultraviolet light.

In Photo 3A and B you'll notice on the left we have the face, one face of a major fracture. It appears as green in the UV photo and as clear on the plain light photo.

In the righthand photograph we see the elements of our secondary poroisty system. We see vertically trending microfractures. We see true intergranular porosity represented by the blobs, if you will, of red dye and fluorescence. We see what apears to be intergranular fracturing, microfracturing, and in some instances we see what appear to be intergranular, what I call sheet pores, which are thin pores found between the grains in the sandstone.

This, for purposes of scale, the grains we're seeing in this photomicrograph come under the size classification of very fine grained sandstone.

Q Okay, let's turn to look now at Photographs 4A and 4B and could you briefly tell us what's reflected on those photographs?

A In 4A and 4B we've gone up to the A Zone, that first photo was in the B Zone, and we've taken a look at another one of these thin centimeter thick or less sandstone laminations. Once again we see a very fine grained sandstone. In this particular photo we see a vertical trending microfracture feeding into sheet pores and intergranular porosity.

Q Anything else you want to comment on with regard to Photographs 4A and 4B?

A No.

Q All right, sir, let's turn now to 5A and 5B.

A In Photo 5A and 5B we're looking at another pair of plain light and UV photos.

First I'd like to apologize for the quality of Photo 5B; they're slightly out of focus, but again we can see that -- in this case we see principally two types of porosity present. We see sheet pores and intergranular porosity. Even though in this particular photo we're some distance away from a fracture face, in terms of some distance I'm talking about maybe -- maybe all of an inch or two, we still see interconnected porosity around the grains and connecting up the intergranular, typical intergranular porosity.

Q I don't think we can say much about 5B because of the way it looks.

Let's look now, if we could, at Photo 6. Could you tell us what's represented in that photo?

A Okay. The -- first I'd like ot make a point that would probably help everybody in their orientation here.

All of the photos in this exhibit are oriented so that the horizontal in the core parallels the long axis of the photo, so that when you're looking at the photo so that you can read the legend, the horizontal in the core parallels, is also horizontal.

Q Okay, let's look at 6 and there is a major orange area running down through the center of that photograph. Is that a vertical or horizontal?

A That is a vertical fracture.

Q All right, sir, thank you. Now go ahead and talk about Six. Thank you.

A Okay. The next series of photos, Photo 6 and on, are excerpted from the Terra Tek report on the Mallon Oil Davis Fed 3-15 core. These are slightly less enlarged than the ones I just showed you. They are enlarged approximately 100 times and within the legend for each of these photos I've provided you with Terra Tek's interpretation of the photo.

Of particular note in Photo 6 is first that we see the vertically trending microfractures, which are cross-cutting the lithologies, and also of note is that Terra Tek put a little arrow on the left side of the photo pointing to some thin orange fluorescing lines around what appear to be grains and those are the same feature that I've been calling sheet pores in the previous photos.

Okay, this one, the Photo 6 is the only photo we have from the B Zone in the Mallon core. In the Mallon core out of ten samples that Terra Tek did a petrographic study on only three of those were from the B Zone; the rest were from the C Zone.

In the C Zone we -- in Photo 7, we see a tremendous amount of orange, fluorescing orange. Terra Tek interprets this to be a kaolinitic filling between the grains that we see here. They do not feel that this kaolinitic filling is capable of storing and releasing oil.

I should just like to point out though

that this filling did absorb the epoxy, which has a viscosity 60 times greater than the oil we produce from this reservoir.

Q Turning now to Photos 8 and 9, would you address those for us, please?

A Photos 8 and 9 are also C Zone photos from the Terra Tek report. This photo illustrates what consider to be a problem with the Terra Tek report, at least a potential problem.

If I might read Terra Tek's description, they say, "This is a fluorescence micrograph of a large open fracture typically responsible for most porosity in these rocks."

I have some problem with them calling that a fracture that would be open at depth. You'll notice that it's oriented horizontally. It's probably a bedding plane fracture that occurred during some stage of perforation of the sample. It may have been existing naturally but it certainly wasn't this wide. If you look at the two sides of that fracture you can see that they are offset down-- the lower half is offset down and a little to the left. If you put them back together they would match quite closely.

Another interesting feature of this photo is that they show us microfracturing cutting the grains, and also what Terra Tek calls leak off matrix porosity. What they consider this to be is porosity that surrounds the fracture and is apparently capable of storing fluids.

I should also like to point out that all of the photos in the Terra Tek report, I double checked this with Mr. Bereskin, who wrote the report yesterday, all of the photos in that report were oriented the way I have these photos oriented.

I believe Mr. Ellis presented a couple of photos yesterday that were vertical on his exhibit. Those, if you want their true orientation, should be rotated ninety degrees.

Q Okay, let's look at Photo No. 9, please, and if you'd briefly describe that.

A Photo 9 simply represents the -- I guess the abundance of some of the intergranular porosity that you can have connecting around these grains. I'm not quite in agreement with Mr. -- or with Terra Tek's interpretation. Their description of these is pull-apart porosity where grain-to-grain contacts have pulled away from one another.

I am not sure the genetic implications are correct. If this sample was from near a fracture face that's certainly plausible. These also bear a resemblance to what we would call sheet pores, which occur naturally between the grains in the rock.

Q All right. At this time, if you would, please, let's refer to the pages following those photographs and would you please describe what's reflected on the first of those graphic displays?

A The first is a plot of permeability versus porosity of the routine plug analysis from the Lindrith B Unit NO. 38 core, which was taken by Mobil and analyzed by Core Laboratories.

Now, this sample -- these -- these samples were prepared somewhat differently than the Terra Tek samples in a manner which I feel is much more appropriate for these rocks in determining porosity and permeability.

I've drawn, you'll notice on this sample that up to the left of the line that's drawn on this transecting the photo, there are a number of diamonds. These diamonds represent approximately 10 bad samples that we had that fractured during the process of the routine core analysis. You'll notice that this line -- there is also a few diamonds to the right of the line and a few crosses, which represent good samples, to the left of the line. The lower limit of the porosity/permeability plot is at 0.01 of a millidarcy, which is the lower testing limit in routine plug analysis.

What this plot summarizes is the porosity and permeability characteristics, at least what the crosses on this exhibit summarize, are the porosity and permeability characteristics of what we're calling the matrix system in the rock.

Q Okay, and to restate as I understand it, the diamonds are samples which you may believe has sample problems and the crosses represent what you believe to be valid?

A That's correct.

Q All right, sir, let's turn the page and address the next plot, if you would, please.

A The next plot simply superimposes the Mallon core data on top of the Lindrith B-38 core data. We can see that this -- the green represents the Lindrith B-38 data. The blue crosses represent the data from the Mallon core, which Terra Tek did not witness any desiccation cracks in.

Q All right, sir, what is the source of the diagonal line running through this graphic display?

A That's simply the same line shown on the previous display. It's simply a reference line, if you will.

Q A reference line which generally separates those points which you believe may have cracking problems during sampling from the rest of the samples?

A In the B-38, yes.

Q All right, sir. Looking at particularly the display that we had in front of us before, what conclusions can you draw?

A Well, first of all, I think that the Mallon core data we have to ignore because there was such a problem with desiccation cracks. Well over -- over 50 percent of the samples from the Mallon core appeared to have desiccation cracks to Terra Tek. Whether or not those cracks are actually affecting permeability, we'll never know. There's no way of knowing. I've got my doubts, but that's not for this hearing.

So we have to go back to the B-38 core data to get a good impression as to what the matrix is doing.

In the B-38 we had only 10 samples, or 12 percent of the total samples crack during the analysis process. In addition, we have another 17 points, or 21 percent of the samples which did not have a permeability high enough to measure by the -- in routine core analysis, less than one 0.01 of a millidarcy.

That leaves us with 54 good data points. You'll see that these 54 good data points form a wide scatter. In traditional permeability/porosity plot interpretation, you like to see a -- all the data points winding up in a straight line, or close to a straight line, defining a definite trend, such that when we see an increase in porosity of X magnitude, that is we also see a corresponding increase in permeability, at least when displayed in a log normal plot like you see here.

What this dispersion of points indicates is that we do not have a single porosity type in these rocks and as the -- and this is also seen in the photos we just looked at. What we have is a complex interrelationship of several porosity types. We have typical intergranular porosity. We've got sheet pores which have -- which would be typified by a, I guess a pore width. It is very close to the (unclear) width, and we have microfracturing. So there is, if we could separate out each of these different types of porosity, which we cannot, then each separate porosity type would form a straight line in this type of analysis, but since these porosity types are intermixed in varying proportions to varying degrees, we get the scatter that we see on this plot.

Q Okay, any other general conclusions with regards to the contents of Exhibit Two, Mr. Faulhaber?

A No, sir.

Q All right, sir, let's put that aside for a moment.

Mr. Faulhaber, were you present here at this hearing when some concern about water saturation was expressed?

A Yes, I was.

Q Mr. Greer has previously expressed the idea that a high water saturation in a surface core may represent a high water saturation level in the reservoir. Do you agree with that?

A No, I do not.

Q And could you tell me why?

A In simple terms it's because both of these cores were drilled with water based mud. A great deal of the oil in the core, perhaps, most of the oil in the core, that existed at depth would have been flushed from the core.

Just as a general rule of thumb at that depth you have a core that is 70 percent oil and 30 percent water, when you core that, when you take that core, then the simple process of taking the core where you're -- with the water based mud, where your mud is invading the core and flushing the core, the oil saturation could be reduced to say, well, a common ballpark number would be 15 percent and your water saturation would be increased to, say, on the order of 85 percent.

If you bring that core to the surface and some gas comes out of solution, that gas, depending on how much is in solution, will expel a little bit of the oil that's remaining, maybe dropping to down to, say, 13 percent, and might expel some of the water, maybe dropping it, say, down to 60 percent.

When we look at the saturation values for the Mallon core, which, we see that, and there are, you know, there are some problems with those saturation values, but we see an average oil saturation of, I believe, 14 percent and an average water saturation of about 66 percent. So this is perfectly consistent with what normally goes on during the coring process when you're talking a core in an oil reservoir. When you're taking an oil saturated rock that's saturated with oil at depth and bringing it to the surface in the coring process.

Q Mr. Faulhaber, in discussing Exhibits One and Two we discussed two elements of a porosity system.

Could you briefly summarize the conclusions which you draw from examination of those exhibits?

A What I see are two major porosity systems. The televiewer and the megascopic features of the core show us a major open fracture system that is of quite an extent vertically, and that crosses lithologic boundaries.

Feeding into that major fracture system we have a, what we've been calling a matrix porosity system that although it is tight by traditional standards, contains fluids, presumably oil, that do not have to migrate very far, and which migrate in these sand laminations to the major fracture system.

Q Anything further?

A No.

MR. PEARCE: Nothing further from this witness, Mr. Chairman.

MR. LEMAY: Thank you. I think this may be a good point to break for lunch before we go into cross examination.

MR. PEARCE: Before we do that, if I may, Mr. Chairman, I'd like to move the admission of Mobil Exhibits One and Two.

MR. LEMAY: Without objection the exhibits will be admitted for evidence.

Okay, we'll reconvene at 1:10.

(Thereupon the noon recess was taken. Thereafter at the hour of 1:10 p.m. the hearing was continued as follows, to-wit:)

MR. LEMAY: Please be seated. The meeting will come to order and we will continue. It's my understanding that you are through with direct examination, is that correct?

MR. PEARCE: That's correct, Mr.

Chairman.

MR. LEMAY: Anything, Mr. Lopez?

Are you ready for cross examination, Mr. Carr? Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

JOHN J. FAULHABER,

resuming the witness stand and remaining under oath, testified as follows, to-wit:

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Faulhaber, I have during the lunch hour placed some tabs on the MMM Exhibit Eight, I believe it is. It's the second derivative analysis of the Gallup structure, and I'd like to simply have you orient with me to make sure I've done this correctly so that when I sit down and start discussing these wells with you we'll have an idea of exactly where we are.

You've described for us the Mallon core data for the Mallon well. Have I correctly put the sticker to locate the Mallon well in Section 3?

A Yes, you have.

Q All right, sir, and while you're still here, I've located also what I understand to be the Mobil well for which the -- we'll simply call that the Mobil core, is that correctly done?

A That's correct.

Q In addition you gave us two wells that are outside of the existing boundary of the Gavilan Mancos Pool in which you did two televiewer logs?

A That's correct.

Q And the first that we discussed was the Mobil televiewer log on the B-73 Well. Have I located that correctly?

A That's correct.

Q And then the second one was the B-74 televiewer log and have I located that correctly?

A Yes.

Q In addition, finally, there is also a Mobil well called the B-72 in between the two wells that have a televiewer log. Have I located that correctly?

A Yes.

Q All right, sir, thank you. I'd like to discuss with you my recollection of some of the points in your testimony concerning what I understood you to say was the distance or the separation between fractures. My recollection was that you were seeing fractures based upon your information whereby those fractures are spaced between 2, 4, 6 inches apart?

A Yes, and as close as 1/2 inch.

Q We're looking horizontally?

A In a horizontal direction, yes.

Q Horizontal direction, and if I have a fracture the next one could be anywhere from 2 to 4 to 6 inches?

A That's correct.

Q Okay. I don't remember if you told me if that's the distance between major fractures, as you've characterize them.

A Yes.

Q When we look at one of these televiewer logs, were there any televiewer logs run in the West Puerto Chiquito Mancos Pool?

A No, not that I know of.

Q And within the current existing boundary for the Gavilan Mancos Pool were there any televiewer logs run for wells within that area?

A None that I know of.

Q Did you run a televiewer log on the B-72 Well?

A Yes, I did.

Q Is it similar to the two that you've depicted for us today on the B-73 and the B-74?

A Yes. In the B-72, and the reason why we did not present it as an exhibit, we did an extensive comparison between the Mobil televiewer, the Schlumberger license of that televiewer, and the Schlumberger FMS, formation micro-scanner. All those will give you fracture orientations. We considered that. That was a fairly expensive comparison and we did not care to release that data.

Q Am I correct in understanding that of the Gavilan Mancos wells, as well as the West Puerto Chiquito Mancos wwells, that probably no more than one of those wells that has been completed so that it will flow oil to the surface under natural conditions?

A I don't understand the question.

Q All right. Are there any wells in the Mancos that when they were drilled were able to flow oil to the surface without being fractured?

A I have no idea.

Q If you'll take that as correct, that there was only one well that could flow naturally without a fracture treatment in the reservoir, do you have a geologic explanation as to why the wells have to be fractured in order to flow when we see the kinds of fractures you are telling us exist in the Mancos reservoir?

A With those wells that were drilled with mud, yes, I do.

Q When we look at the televiewer log, can you give us a feel for the relative scale of what we're doing in terms of the total vertical interval versus what you're examining with the individual fractures that you see in the televiewer?

A I'm not quite sure I understand what you -- what you need.

Q All right. What fraction of the total vertical depth of the Mancos reservoirs is investigated by the televiewer log?

A In all three wells we ran the televiewer from -- we didn't -- we haven't shown you all of our televiewer logs. We ran the televiewer from the base -- well, from the, what's commonly termed the top of the Upper Carlile Shale, through the top of the Mancos interval.

Q Within that interval what fraction of that investigation represents the actual fractured intervals?

A In the B-73 the vertical extent of fracturing was on the order of 700 feet.

In the B-74 the vertical extent of fracturing was 92 feet.

Q When we add to that the circumference of the investigation in a horizontal extent, what is that diameter or circumference we're dealing with horizontally?

A You mean what's the depth of investigation of the tool?

Q Yes.

A It's reading the borehole wall.

Q When you add that dimension to the vertical dimension, am I correct in understanding that you're investigating a very, very small portion of the total reservoir?

A That's kind of a simple-minded analogy, but yes.

Q That's all I have to work with today. When we talk about these fractures, and I'm not sure I was clear on what you said, are you meaning to imply that there is a dominant direction with regards to the fractures in the Gavilan Mancos or the West Puerto Chiquito Mancos reservoir?

A What I see is an orientation in the three televiewer logs that is the same between all three logs. The principal orientation of the fractures in North, 14 degrees East. In the B-38 core I saw evidence of only one fracture direction, one principal fracture direction. In my examination of the Mallon core I saw evidence of only one fracture direction. I find it very interesting that this fracture orientation is very similar to the dike system which we have developed north of the Gavilan reservoir, part of which is found very close to the Gavilan reservoir in the

Tapacitos Ridge, which I'll point out on the map.

The Tapacitos Ridge is located approximately like this at about that orientation.

Q Do you recall Mr. Emmendorfer's testimony that believed that there was a fractional direction, or direction to the fractures, if I recall correctly I think he oriented them northwest to southeast generally across the reservoir.

A You mean in the August hearing?

Q Yes, I believe that's correct.

A I recall that --

Q Do you remember that?

A -- yes.

Q Can we use the televiewer log. does it give us the ability or the scale of observation for these fractures so that we can utilize that logging device as a way to tell us what the orientation of these fractures is?

A I believe so, yes.

Q Will that tell us what the orientation of the fractures within the total reservoir are?

A I think you have to take each piece of evidence as it exists and see what they add up to. We've got three televiewer logs that have the same orientation and I would presume that that's a fairly -- that's fairly convincing to me that we've got a strong fracture orientation.

Q Am I correct in understanding that of the available core information, what you had from the Mallon core, that you have not plotted the porosity/permeability data that you did on the Mobil core?

A I'm not quite sure I understand you. On the -- in my exhibit, the second porosity/permeability plot, I have plotted all of the known core data on that plot.

Q If we look at the Exhibit Two package, the last white sheets, the first of those is the plot of the permeability versus porosity on the Mobil core?

A That's correct.

Q And then the secod one is where you've added in the Mallon core data?

A That's correct.

Q How many plugs were there in the Mallon core?

A I believe there were about 150.

Q And of those plugs how many did you utilize for plotting purposes?

A Let's see, all but 11 samples are on this plot.

Q With regards to the Mobil core, how -- there were 81, I think, original plugs?

A I believe that's correct, yes.

Q And how many of those plugs did you utilize?

A All but 17 are on this plot.

Q Okay. On the first page, the first one, it shows just the Mobil core, is that the same plot that you presented to the Commission at the August hearing?

A I don't believe it's precisely the same plot. It's the same data.

Q Did you re-plot the August -- did you re-plot the core data from the Mobil core and prepare a new exhibit for today?

A Yes.

Q Is the difference in the two exhibits the fact that in the August hearing you plotted all 81 plugs on the Mobil core?

A Oh, are you referring to -- the plot in this exhibit does not include those data points which had a permeability of less than one 0.01 millidarcy. I left those off because that date, we simply have no permeability value and the other one I simply plotted them down below that at a hypothetical value.

Q Will you summarize for me how there's a difference between the August plot and the plot we have today so that when I look at the two together I'll understand what you did?

A In the plot I presented today, since the

-- we only have permeability values down to a level of one 0.01 millidarcy, I cut off my plot at that point.

In the August hearing I presented a plot which went down, I believe, to one 0.01 milidarcy. I don't remember what the top scale was, and I believe I plotted all of those samples which were listed in the core report as being less than one 0.01 millidarcy, I think, for the purposes of plotting, I plotted them at one 0.001 of a millidarcy.

Q In taking the core data from the Mobil core, have you determined what the porosity cutoff was for that area of investigation in the core? What did you use?

A In August I used a one percent porosity cutoff. At the moment I don't use any.

Q Okay, we wouldn't use a cufoff, then, in examining the current information.

A No.

Q All right. With regards to a permeability cutoff, what number did you use in August, do you remember?

A One 0.01 milidarcy, I believe.

Q And you used that again today?

A Yes.

Q In looking at the core, the interval core, approximately how many feet of net pay in that interval was cored and analyzed?

A In the B-38?

Q Yes, sir.

A I don't recall right off the top of my head.

Q Your testimony in August was that it was 50 feet of net pay. Does that refresh your recollection?

A Yeah, that's what I said in August.

Q Is that still correct?

A I'm not -- I don't consider the term "net pay" to have that much meaning at the present.

Q What, using the current information and forgetting for a moment the August compilation of that data, what is the mean permeability that you have used for this core?

A Could you repeat the question?

Q Yes, sir, when we plot the data, analyse it, and study it --

A Uh-huh.

Q -- and I'm ready to do some calculations, I want to do a material balance calculation or a volumetric calculation, I ask you for the average permeability.

A Okay, when I -- I have not recalculated those with using no cutoffs.

I believe in August I used an average

permeability of the -- using the one percent porosity cut-off, I think I used an average permeability of .048 milli-darcies.

Q That's my recollection, too. When you talk about average permeability, what have you averaged?

A You've averaged all the plug samples you have data for.

Q Is that an arithmetic average of all the data points?

A Yes.

Q In talking about the average permeability that you had in August, the .048 milidarcies --

A Yes.

Q -- having eliminated the cutoff, if we recalculated it taking off the cutoff, would we have lower average permeability?

A Probably, yes.

Q I told a witness yesterday I know enough engineering to be dangerous and I've proven that just now. I understand that when engineers talk about wells that are naturally completed, they don't necessarily mean that it will flow oil to the surface. It simply means prior to stimulation, all right? Did I confuse you by telling you otherwise?

A No.

Q You talked about the fact that the well had been drilled with mud.

A Yes.

Q Should a well drilled with air require fracture stimulation to produce naturally? Do you have a geologic opinion as to whether that would make a difference?

A I don't have any experience with air drilling on wells out here.

Q Thank you.

MR. LEMAY: Mr. Carr?

CROSS EXAMINATION

BY MR. CARR:

Q I have just a couple of questions. Mr. Faulhaber, I'm going to ask you a couple of questions about the Lindrith B Unit No. 73 Well to be sure I understand your testimony. That well you initially completed in the C Zone, is that correct?

A That's correct.

Q Were you producing any water in the C Zone?

A We were still returning load water.

Q And when you stabilized it were you producing water at that time?

A Yes.

Q And you were producing how many barrels of oil, 10 barrels of oil a day?

A Yes.

Q Based on that amount you decided to set a bridge plug and move away from that and go up and complete in the A and B Zone.

A Yes.

Q Is it your testimony that that 10 barrels per day in the C Zone is indicative of what the C Zone will produce in the Gavilan area?

A We have another -- a number of these types of tests and I don't remember the exact wells. I believe the -- in the well that was cored, the Mallon Davis Fed 3-15 the C Zone only produced a few barrels of oil a day, 5 or 6.

In the -- I think that the ability of the C Zone to produce is directly related to the amount of fracturing. It appears that the C Zone does not, in the Gavilan area does not fracture as readily as the A and B Zone, so it is our current operating philosophy that, as we did on the 74, that when we do not see fractures in the C Zone, we will not complete it.

Q And is that well, in your opinion, indicative of what the C Zones does in that area?

A In what area?

Q In the Gavilan area?

A From the evidence I've seen it appears to be typical of the Gavilan area.

Q And you set a bridge plug and that segregated the C Zone from the A and B.

A That's correct.

Q And it's a separate zone.

A That's correct.

Q You didn't see any communication between the C to the A and B, did you?

A No, we ran after-frac logs after both our frac jobs and also a pretty thorough suite of cement bond logs, and we see no evidence of communication between the two zones.

Q And the A and B Zone is stabilized, you say?

A No, it's not stabilized.

Q It's still producing frac water?

A Yes, it's returning oil water.

Q And it's producing about 50 barrels a day?

A It was, yes.

Q Is that figure coming down?

A I don't know. I haven't seen a recent production test. We pulled the bridge plug and are doing some other things to the well, so --

Q Do you think that 50 barrels a day is indicative of what the A and B can do in the Gavilan?

A I would like to think that in some areas it could do better.

MR. CARR: That's all I have.

MR. LEMAY: Thank you, Mr. Carr. Additional questions of the witness. Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Yes, sir, in Exhibit Number Two, your permeability versus porosity graph --

A Uh-huh.

Q -- the plugs that were used for these calculations, were they through the same interval that the wells completed in?

A Yes.

Q On your Exhibit Number One, is the direction on the televiewer magnetic north or true north?

A On the televiewer it's magnetic north; on the plots I provided at the back of Exhibit One, those have been corrected for magnetic declination.

Q If you had only one televiewer log that indicated fracture direction, would that provide just a small degree of certainty as to the areal fracture direction or the fracture direction in the area?

A I would definitely like to have more fracture directions, although you can assume that fractures in local area are going to form under a similar stress field throughout that area.

Q So the more televiewer logs that you have to indicate a fracture direction the more certainty you have?

A Yes.

Q Would you care to rate the certainty of -- you have of the fracture directions just based on these three logs you said you ran? Is that 9 percent certainty? 50 percent certainty?

A That's difficult to do. I feel that in that portion of the reservoir that Mobil's wells are in I'm 100 percent certain as to fracture orientation. Well, maybe 95 percent since I'm a geologist.

As for the rest of the reservoir, I look for other data that may be extrapolated from that, such as maybe the orientation of Tapacitos Ridge and those other dikes to the north. That gives some credence to the possibility that the fracture direction we're seeing in the televiewer logs is -- is fairly extensive regionally.

Q Did fracture pressures during treating indicate that there were already existing fractures in these wells?

A I don't know.

Q Did any other information, such as geo-logs or other drilling information that -- fluid lost while drilling, back up your claim of fractures through these intervals?

A Yes, we lost -- it varied between the wells, but we did have -- lose circulation in the Gallup.

I should point out that our drilling engineers have spent a lot of time and we actually rented the rigs out here on a day rate so we could control the mud system very closely, and so our lost circulation was not as bad as it typically is out here.

Q But did the lost circulation areas or places where you lost circulation coincide with the areas where your logs indicated fractures?

A In general when we got to the top of the Gallup, usually we lost a little bit of circulation and we put in a bunch of LCM and maintained that LCM concentration so that once we started drilling the Gallup we did not continue to lose mud.

As far as there being -- I have not made a very close correlation between the mud loss and -- and the televiewer logs.

Q Thank you.

MR. LEMAY: Thank you, Mr. Chavez.

Additional questions of the witness?

QUESTIONS BY MR. LEMAY:

Q I have one possibly for clarification, --

A Okay.

Q -- Mr. Faulhaber. You refer to a secondary porosity system. Is that in a generic sense a post-depositional porosity system or a system separate from the fracture system? The definition of secondary, I guess.

A Okay, it's a system different from the frac -- from the major fracture system.

Q How would you expect that to react -- or maybe this is speculation, it may be an engineering question, but in your diagrams, we're talking about tracing lines --

A Uh-huh.

Q -- and these lines, we'll say major fractures are the lines and then the other lines are also minute fractures or -- or some form of void space that enters into the main-- the main fractures, as you've termed them.

Is that different than just speaking of a fracture system reservoir?

A I -- that is in part an engineering question, and in just general terms I believe we're -- it's a dual -- rather than saying it's a dual porosity system or something like that, it's really a dual permeability system; high permeability, major fractures; low permeability, matrix, if you will.

Q So it refers to the degree of permeability within the rock rather than maybe the type of permeability in the rock, and I'm trying to, an example, I understand a vugular system would react different --

A Right. The first, let's call it a permeability system. The first permeability system that we look -- that we see out here are the major fractures that we see on the televiewer.

The second permeability system is a combination of pore types that I would characterize as being microfractures, what I call intergranular sheet pores, and traditional intergranular porosity.

Did I explain that or --

Q You described it well.

A Okay.

Q I was trying to crystallize what be a singular porosity system and a dual porosity system.

A Okay.

Q Both from a geological point of view and from an engineering point of view, and naturally your testimony would be the geological --

A Right.

Q -- and that's what I was trying to crystallize, the differences.

A Okay.

MR. LEMAY: Mr. Brostuen.

QUESTIONS BY MR BROSTUEN:

Q Mr. Faulhaber, have you been able to quantify the porosity? You do use some numbers here in your Exhibit Two in your porosity versus permeability chart.

Have you arrived at a porosity percentage or an average for fracture porosity and also for intergranular or matrix porosity?

A No. I'm -- estimating fracture porosity is a can of worms and I've stayed away from that.

Q However, have you made any attempt to utilize the porosity logs to determine porosity?

A Yes. In the August hearing I believe we presented one exhibit which will be in the files where we took our sonic log, which responds primarily to matrix, well, should be reading only matrix, non-vugular matrix, but we don't have vugs here, and we provided -- did two calculations on that. First we simply calculated the sonic

MR. LOPEZ: No, Mr. Chairman. In the spirit of the melodrama that we are participating in we feel it appropriate to insert the various chapters of the melodrama as they occur and as we address them.

We don't want to take away any of the expectation.

MR. LEMAY: We appreciate the suspense and that procedure is acceptable.

MR. KELLAHIN: Do I understand we will continue with the practice of hearing by sabotage?

MR. LEMAY: Mr. Kellahin, it's just a matter of style. I think --

MR. KELLAHIN: We go with the books, Mr. Chairman.

MR. LEMAY: -- the MMM style is different than the lead-off style, so we will appreciate both styles.

MR. KELLAHIN: We will comment on that later.

GREGORY B. HUENI,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. LOPEZ:

Q Would you please state your name and where you reside?

A Yes. My name is Gregory B. Hueni and I reside in Denver, Colorado, actually Lakewood, Colorado, at 11420 West 27th Place.

Q By whom are you employed and in what capacity?

A I'm employed by Jerry R. Bergeson & Associates, Incorporated. I am a consulting petroleum engineer specializing in reservoir evaluations.

I'm also Vice President of that particular firm.

Q Have you previously testified specifically with respect to the matters before the Commission in these hearings?

A Yes, I have.

Q Would you describe your educational background, your work experience?

A Yes. I received a Master's degree in mechanical engineering from Rice University, 1971.

I was employed thereafter by Exxon Company U.S.A. and worked in their offices located in Midland, Texas; in Houston, Texas; and in Kingsville, Texas.

In 1977 I left Exxon and went to work for Jerry R. Bergeson & Associates and have worked with that firm since that time.

Q When you were employed by Exxon, what were the range of your duties and work experience?

A While I was with Exxon I worked primarily as a reservoir engineer. I worked also in production and planning, organization, and I also worked as a supervising reservoir engineer.

Geographically I've worked the West Texas-New Mexico area. I also worked in the South Texas area, and then as part of Production Planning Group I was involved in observing Exxon's operations throughout the United States.

Q And since you have been working for Bergeson & Associates, what has been the nature and extent of your employment and responsibilities?

A While with Bergeson and Associates I have worked on fields located throughout the world, most especially the ones that I've worked on overseas have been located either in the North Sea environment or in Western -- West Germany.

While with Bergeson and Associates I've also worked on fields located throughout the United States, as well as in Canada.

The types of work that I've been involved with have ranged from reservoir engineering evaluations and econmic studies. We've completed reservoir studies using classical approaches. I've been involved in reservoir simulation studies in several reservoirs located throughout -- throughout the United States and overseas.

I have taught the industry courses which our firm presents in the area of reservoir engineering and I have also served as an expert witness on a number of different issues.

Q Did you do a study of the Gavilan Mancos and West Puerto Chiquito Pools?

A Yes, I did.

Q And you have testified previously before this Commission and had your qualifications as an expert petroleum reservoir engineer accepted as a matter of record?

A Yes, I have.

MR. LOPEZ: I tender Mr. Hueni as an expert witness.

MR. LEMAY: Mr. Hueni's qualifications are acceptable.

Q Mr. Hueni, I believe you just stated that you did perform a study of the Gavilan Mancos and West Puerto Chiquito Mancos Pools. By whom were you asked to perform this study?

A Our firm was contacted by a number of the working interest owners in Gavilan Mancos Pool. Those working interest owners include the following companies: Mallon, Mesa Grande Resources, Amoco, Mobil, Koch, Reading & Bates, Hooper, Kimball & Williams, Tenneco, Kodiak Petroleum, and American Penn Energy.

We performed the study on behalf of those particular parties.

Q And what did this study consist of?

A The study consisted of an evaluation of the Gavilan Mancos Pool with the objective of determining the optimum method for depletion of that pool.

Q And what was the objective of the study?

A Well, the objective was to determine the best method of depletion of the pool, whether it would be best to deplete the pool on a primary depletion basis or whether it would be perhaps better to -- to unitize and inject gas into that particular pool.

The study itself consisted of several different phases. It involved a considerable amount of testing, both in the field type testing as well as laboratory testing. It involved geological analysis which we're heard described previously that was conducted by Mr. Emmendorfer and Mr. Faulhaber, and it also included an engineering analysis of the pool itself.

Now I might go ahead and I could refer to Figure One?

Q Sure. I think when you performed your study was one of the things you considered reservoir performance, and in this connection I'd ask you to refer to the Tab 2 in the report that we just circulated and ask you to explain what it is.

A Okay. Okay, in performing our study the basic approach to our study which we would like to describe today was to review the reservoir performance; follow that by attempting to describe the reservoir as completely and accurately as we possibly could. Then once we had that description, to analyze the reservoir using appropriate methods of analysis, and then once we analyzed the reservoir we wanted to put some economics to it and we completed an economic analysis, and as a result of that we arrived at our optimum plan of depletion.

The first section that we are going througn, which we wanted to hand out so that we would be able to preserve the flow of the -- of our engineering study, deals with reservoir performance, because this is really the first activity that we undertook in completing the study.

The first part -- well, when we reviewed reservoir performance, there were several things that we -- we had available to look at.

We had production trends that were available to look at. We had individual well tests were available to look at. We had production control surveys, or production logs that were available to look at. We also had pressure information that was available to look at and this information is what we've attempted to describe under the first tab, Reservoir Performance.

Q Okay. Go ahead and explain what else you want to show with this part of the exhibit, if you will.

Q Okay.

MR. KELLAHIN: I'm going to object to that question, Mr. Chairman. It makes it very difficult to follow the testimony if he calls for a narrative answer from this witness.

In properly conducted direct examination Mr. Lopez should be putting a specific question to this witness so we would know whether it's objectionable and so that we would have an index before this man answers the question of whether or not it's appropriate testimony.

To simply plug him in and let him run is not appropriate hearing procedure. We object.

MR. LEMAY: Mr. Lopez, do you have a comment on Mr. Kellahin's objection?

MR. LOPEZ: Mr. Chairman, as we all know, the rules of evidence are more informal (unclear) Commission hearings. If we were to observe strict formality as you'd expect in a court of law, I'm sure we would have been objecting all the first day with respect to Mr. Greer's narrative testimony.

I think the purpose of these hearings is to try and find out what this reservoir is about and how the best method of producing it is.

If you wish, I can ask Mr. Hueni to refer to each page under this section and ask him to explain what it shows, but I think it's better in the narrative form for everyone to understand without interrupting testimony.

MR. LEMAY: I think that's been used at -- if you can, to satisfy Mr. Kellahin's objection, just say you want to continue on with production performance, for instance; refer to the exhibit that he is describing and I think that will keep us all oriented and will pretty well tie down what part of the testimony that he is currently based in.

MR. KELLAHIN; It would be very helpful to see if we couldn't organize it so we can understand the areas that he's focusing in on.

MR. LEMAY: That was my suggestion, to just refer to the exhibit, continue on with the exhibit, and then we can all stay with him.

MR. LOPEZ: Okay.

Q I believe we are referring to the section under Tab 2, is that right, Mr. Hueni?

A That is correct.

Q With respect to reservoir performance. Okay, what did you consider when you were making your study with respect to reservoir performance?

A We considered the production performance of the field as a whole as well as the individual pools which comprise that field.

Q I'd ask you then to refer to what is Figure 2 behind the blue tab and ask you to explain what it shows.

A Figure 2 is a production plot showing the production history for the Gavilan Mancos Pool as proposed in the Mesa Grande, et al, application to expand the pool. In other words, this is the production history for not only what has traditionally been known as Gavilan Mancos Pool, but also includes production from the western tier of Canada Ojitos Unit wells, or West Puerto Chiquito Pool wells.

This particular plot that we have shows the production history for all of the wells in the Gavilan Mancos Pool. We've attempted along the top of the page to give some indication of the number of wells that are either on production or that appear to be capable of producing at a given point in time. This compares to a number of wells producing as indicated by Mr. Roe, but his were wells actually on production in a given -- given month, whereas we've included some wells that are simply capable of producing.

The scale of the exhibit on the Y axis shows daily production. It's expressed in barrels of oil per day. It's on a logarithmic scale with the bottom of the graph showing a value of 10, the value of 10 to the 2nd power represents 100, 10 to the 3rd represents 1000, and then the top of the graph would represent 10,000 barrels a day.

We show production on a monthly basis from date of first production in 1982, which was the Gavilan No. 1, through January of 1987.

We would like to note that the -- this particular area, Gavilan plus the western tier of Canada Ojitos Unit wells, in January of 1987 was producing about 3,650 barrels a day. It had accumulated 3.15-million barrels of oil. It was experiencing a current GOR slightly under 2,400 standard cubic feet per stock tank barrel.

Q For comparative purposes what is the total cumulative production of the West Puerto Chiquito Mancos Pool, if you know?

A Well, if we were to take the remainder of the West Puerto Chiquito Pool that we did not include in this particular exhibit, we would find that by October of 1986 that the cumulative production from that area amounted to about 8.44-million barrels, producing at a gas/oil ratio of 880 and producing at a rate of 1,643, or 1,640 barrels of oil per day.

Q And when was the West Puerto Chiquito Mancos Pool first put on production?

A That represents the production that's been accumulated in that pool since 1962.

Q And the over 3-million barrels that has been accumulated in the Gavilan Mancos has been accumulated in what time frame?

A Well, there was some production in 1982. That was rather a minor amount of production; basically production in the Gavilan Mancos area started in mid-1983.

Q When were the West Puerto Chiquito Mancos Pool wells that you included as part of the Gavilan Mancos Pool production first put on production?

A They were put on production in 1986.

Q And why have you included these wells as part of the Gavilan Mancos Pool?

A We've included these wells because we believe these wells are in very good pressure communication with Gavilan Mancos Pool, that the depletion of Gavilan Mancos, Gavilan Mancos Pool will parallel their depletion. We've included them because we believe that a substantial amount of their production comes from the Niobrara A and B Zone, as we believe that the majority of Gavilan Mancos Pool production comes from the Niobrara A and B Zone, as well, and we've also included them because the presence of a synclinal area in a gas injection project represents a logical termination of an injection program.

Q And these wells that are included are the wells in the most western tier of sections in the West Puerto Chiquito and are included in the proposed Gavilan Mancos extension.

A That is correct.

Q I'd now ask you to refer to what's been identified as Figure 3 and ask you to explain what it shows, and if you would, compare it to the previous exhibit.

A Figure 3 is a very similar plot with the exception that we've excluded the production from two wells from this plot. The two wells that we excluded were the Gavilan Howard Well and the Gavilan No. 1 Well.

In the preceding hearing that was held on this matter a concern was raised by other parties that these wells may not actually be reporting production or their past production may not actually have reflected Mancos Zone production because they were either dually completed with mechanical problems or because they had been commingled with Dakota production, and we've reviewed that information and we too believe that that is possible that those two wells have recorded some production as Mancos production that actually came from the Dakota.

So we have excluded those two wells from our production -- production plot.

If we compare Figures 2 and 3, we see that that does not change really the shape of the field curve. We still have a rapid build-up in production from 1983 to the middle of 1986. We have a fairly constant gas/oil ratio performance until 1986, at which point in time we have a moderate increase in gas/oil ratio performance. Gas/oil ratio field-wide is about 2337 standard cubic feet per stock tank barrel, which I think we're going to show is not unduly large, at least on the field total basis, and the other -- the other point, the other reason that we show this performance trend is because when we subsequently interpret performance of the field, we want to be able to set forth an interpretation that is consistent with the performance that we see on this particular chart for the field as a whole.

Q I'd now ask you to refer to Figures 4 through 11 and ask you to explain what these figures show.

A Yes. All of Figures 4 through 11 are

similar type of production plots that are presented for individual wells. They show oil production expressed in barrels of oil per producing day. In other words, we've taken the barrels of oil that each month produced, divided by the number of days reported on production. We've plotted that information and we've also plotted the gas/oil ratio information.

The oil production is shown by the triangles. The gas production is shown by the x's, or the gas/oil ratio production is shown by the x's.

We have several wells here. I don't believe it's necessary to look at each individual well. The purpose of the -- of the comparison of wells is to illustrate that individual wells in the pool do not have necessarily common producing characteristics. So if we were to look at the very first one, Figure 4, which is, as shown by the title, the production history for the Mallon Fisher 2-1, located in Section 2 of 25 North, 2 West, we would see a well that has been capable and has produced over a period of time at rates of 500 barrels of oil per day.

It initially produced with a gas/oil ratio of 800, later dropping down a bit to around 400 in early 1986, and then the gas/oil ratio increased in about the middle of 1986 and appeared to stabilize at a rate of about 1,200 to 1,300 cubic feet per barrel.

One of the points that we'll be making later on is that this type of behavior is not characteristic of a solution gas drive reservoir. We can take Figure 4 and look then at the offsetting well, which is a well known as the Ribeyowids.

Q Mr. Hueni, would it be helpful to point out where these wells are on the structure map?

A Certainly, it would be.

Okay, that is the location of Mallon -- the Mallon Ribeyowids Federal 2-16, located in -- also in Section 2 of 25 North, 2 West.

Now this well, whereas the other well demonstrated producing rates of 500 barrels a day, this well demonstrated a maximum producing rate of 215 barrels a day. it produced at reasonably low gas/oil ratios, approximately 500 standard cubic feet per stock tank barrel until the middle of 1986, and at that time its gas/oil ratio performance took a steep upward turn and then leveled off. It currently is about 3,600. The well is producing about 87 barrels a day. It is basically producing at capacity where the well that we looked at previously is not producing at capacity.

We would suggest that the shape of the gas/oil ratio curve on this well is also not characteristic of a solution gas drive reservoir.

The Figure 6 shows the Mesa Grande Rucker Lake No. 3 Well, which is a well that's produced at a relatively constant producing rate of about 100 barrels a day since the middle of 1983. It's gas/oil ratio performance in 1984 was approximately 1700 -- or it rose to as high as 1700 cubic feet per barrel, dropped down to 500 cubic feet per barrel and then increased in about the middle of '86 up to around 1,257 standard cubic feet per barrel. That was the January '87 number. The oil production rate is at 64. Once again we do not believe that this is indicative of a reservoir that's performing as a solution gas drive reservoir.

This also happens to be a well that is relatively high on the Gavilan Dome structure. It is not a well that is low on structure.

The Figure 7 is the production history for the Native Son No. 2 Well. This particular well is the well that has accumulated the most production out of the Gavilan Mancos Pool since it was discovered. Its cumulative production amounts to approximately 360,000 barrels of oil.

As we can note, it has had a very high capacity flow rate since 1984, reaching rates as high as 530 barrels of oil per day.

The gas/oil ratio performance is different than the ones that we looked at previously. Gas/oil ratio, which was around 5-to-600, began increasing in 1985 and since that time has increased at a maderate rate of increase to a current value of about 4,300. Once again we would suggest that this is not characteristic of wells that are in a solution gas drive reservoir.

The next figure, Figure No. 8, is the performance for the McHugh Full Sail No. 1, located in Section 29, 25 West, 2 North. This is a well that is on the flank of the Gavilan Mancos Pool.

The productive capacity of this well during 1985 was demonstrated to be on the order of 225 barrels a day. The gas/oil ratio was around 1000 at that time.

In early 1986 it took an abrupt increase up to approximately 1,900, and then the gas/oil ratio through 1986 increased moderately to 2,600.

Once again we have seen a gas/oil ratio increase in this well but we do not see that as being typical of a solution gas drive reservoir.

Figure 9, the Rucker Lake No. 2, is a well that is once again very high on structure. It's a well that has demonstrated producing capacities of 150 barrels per day for a short period of time on a daily production basis. It was tested at rates as high as 400 barrels a day.

The gas/oil ratio declined a bit between 1984 and 1985 to a level of about 5-to-600 standard cubic feet per stock tank barrel.

It increased in the early part of 1986 and increased up to a current value of about 3,800 standard cubic feet per stock tank barrel.

This well has experienced a little more steep increase in its gas/oil ratio performance; perhaps this might look a little bit more like a solution gas drive well, although it doesn't, according to the analysis that we've done, even this well doesn't really look like a solution gas drive.

Figure 10, I only have two more of these to go through but we're trying to point out the variability of the producing characteristics of the different wells in the Gavilan Mancos Pool, Figure 10 is the production history for the Janet No. 2 Well, operated by Mr. McHugh, located in Section 21, 25 North, 2 West.

The production history on this well shows a well that produced at a constant rate of approximately 60 barrels a day in '84 and '85. The gas/oil ratio in '84 was in the range of 5-to-600, increased to 800 to in excess of 1000 in 1985, and in 1986 took an abrupt increase in about April to a maximum value that was recorded in December of 6,900, followed by a slight GOR decrease in January of 1987 to a level of about 5,500 standard cubic feet per stock tank barrel.

And finally we have the production plot

for the Janet No. 1 Well, also a well operated by Mr. McHugh, located in Section 27 of 25 North, 2 West.

This well tested at high rates, 300 barrels a day for a few days in 1983, but basically, since it's been put on production has produced at an average rate of about 100 barrels a day since that time.

The GOR initially in 1984 reached levels of around 900, dropped down to the 5-to-600 range in 1985, and then abruptly increased in mid-1986. The first increase was up to a rate -- that occurred in about June -- was to a gas/oil ratio of 2,600 and then subsequently, later in the year, up to gas/oil ratios in excess of 10,000. Current GOR is running at about 12,300.

Q Okay. Mr. Hueni, I'd now ask you to refer to the first set of maps under the map tab at the back of the book and ask you to identify and explain what the first map shows.

A Okay. Once again we are going through the individual well performance information that we looked at in trying to arrive at an understanding of the field itself.

The plots that we've looked at up to this point in time have indicateds a certain degree of variability between individual well performance, and in looking at reservoir performance we wanted to look at additional indicators of variability, so we set out a series of maps and the the first map is a map that shows several wells in the -- in the Gavilan Mancos Pool, as well as along the western tier of sections in the Canada Ojitos Unit, and what we've attempted to do is picture the areas that have been developed and the dates at which the development occurred.

We've color coded the individual wells with the first wells being drilled in 1980 or before. We have wells drilled in '81 shown by different color, similarly for the other years.

What we would note is that the first well, first producing well in the Gavilan Mancos Pool, as it's normally identified, is the Gavilan No. 1 Well, located in the northeast of Section 26 of 25 North, 2 West.

That well, then, was, after a bit of production history, was followed by a certain amount of development that occurred in the southern end of the Gavilan Mancos nose.

The subsequent development occurred to the northeast in '85 and '86, when Mallon drilled several wells and certain wells were also drilled by -- by the Canada Ojitos Unit.

Q Okay. You want to refer to the second map of this -- off the record for a minute.

(There followed a discussion off the record.)

Q Okay. Would you -- well, excuse me, before we go to the next map could you explain where the first wells were developed in the Gavilan Mancos Pool and the last wells?

A Yeah. Okay. The, as we said before, the first maps -- or the first wells were developed in the southern end of the pool. Subsequent development occurred up in the northest area. The map is not entirely completed. It's not fully colored in.

There have been several additional wells that have been drilled since -- some of which, well, which are not yet on production. Many of them are not yet on production, at least in December of 1986, at which point in time we used -- we constructed this data.

There are three wells that Mobil has drilled along the south end of the pool, the Mobil B-73, Lindrith B-73, located in Section 6 of 24 North, 2 West; the Mobil B-72, located in 25 -- in Section 8 of 24 North, 2 West; the Mobil B-74 in 24 North of 2 West, Section 9.

In addition to that, along the perimeter we have drilled by Mr. McHugh, we have five wells drilled in Section 25 North of 2 West, and in the Canada Ojitos Unit we have two wells drilled along the -- along the western tier of sections and then there were two additional wells drilled on the second tier of sections from the Gavilan Mancos Pool.

There is one additional well that was not circled. It has not proved to be productive yet. It is the Mallon Davis Well located in Section 3 of 25 Norht, 2 West.

Q So since the hearing in August, and excluding the three Mobil wells and the one Mallon well, all the wells that have been drilled have been drilled by the proponents after they claimed an emergency existed and that no further development should take place?

A That's correct.

Q Okay. I now ask you to turn to the next map, which is identified as cumulative oil and ask you to explain what it shows.

A The second map is a map showing the cumulative oil production recorded by individual wells in the area as of December, 1986. It is -- the cumulative oil production on this map is indicated by different size circles. The largest circles indicate wells that accumulated 300,000 plus barrels of oil and then we grade down in the size of the circles to indicate the different types of recoveries experienced by wells, by individual wells in the pool.

The reason that we point this out is that we've looked at wells and we've seen that they exhibit variable production characteristics. I think if we look at this type of presentation, although we have to realize that wells come on at different points in time, that certainly there has been a wide variation in the type of recoveries that have been experienced by the different wells in the Gavilan Mancos Pool.

In the Canada Ojitos Unit area we show along the eastern edge several wells which have produced certainly in excess of 300,000 barrels. This map does not show the two wells in Section 29 and 32 of 25 North, 1 West, which are Canada Ojitos Unit wells which do have -- have some production that should be shown on here.

Q So the principal purpose of the exhibit or the map is to show the large variability in cumulative production of the various wells in the pool.

A That is correct. We once again are going to present our interpretation of field-wide performance and we are simply pointing out that individual wells represent variations from that -- that performance.

Q Now could you refer to the third map in this series of maps, entitled Cumulative Gas and explain what it shwos?

A The third map shows the cumulative gas production recorded for individual wells since -- since -- or as of December, December 1986.

Once again we have used a presentation in the form of showing the amount of production according to the size of the circle and each of the circles then is colored in red to indicate the gas.

We note immediately that there are two wells in the pool that, well, there are really three wells in the Gavilan Mancos Pool proper that have a large amount of gas production. There is a well located in the northwest corner of Section 23 of 25 North, 2 West. That is Gavilan Howard No. 1, a well that was dually completed in the Dakota in which it was observed mechanical communication with the Dakota had occurred.

The second well is the Gavilan No. 1 Well, located in the northeast of Section 26 of 25 North, 2 West. The Gavilan No. 1 is also a well commingled with the Dakota. At the past prior hearing it was indicated that there was a possibility that this gas was coming from the Dakota and in subsequently reviewing the production histories we decided that we thought that was reasonable ad we consequently excluded those two wells performance from the total field average.

Q Okay. Now could you refer to the next map?

A The next map, and this is perhaps one that you would like to --

Q Yeah.

A -- put up if you can find this one.

Q I'm not sure we have it, so I think --

A Oh, okay.

Q -- the best thing to do is to just have Colin refer to the structure map, where the wells are as you call them out.

A Okay.

Q I think we also need to correct this map --

A Yes.

Q -- that says Maximum Gas Rate, but it should read maxium oil rate, is that correct?

A That is correct. That is noted in the report itself, that this -- that this reflects the maximum oil rate in barrels of oil per day observed as production from the individual wells.

Now some of the wells have always been constrained in producing by the statewide allowable, 702, or by the more recent allowable of 400 barrels of oil per day on 640. So some of the wells, perhaps, have greater capacity than shown on this particular map.

The map does indicate produtivities up to a maximum value of 600 plus barrels of oil per day.

In looking at this I think we would see once again a wide variability to -- of the producing capacities of the various wells. There is a region of -- an area of high productivities in the southern part of Township 25 North, 2 West, the area around the Native Son No. 2, Native Son No. 1, Homestead Ranch No. 1. Those wells are certainly high productivity wells. There's also a very high productivity area up in the northeast portion of the Gavilan Mancos Pool and the adjoining Canada Ojitos Unit area. Those wells also have demonstrated flow capacities in excess of 5, 4-to-500 barrels a day.

But the thing that is also very striking is that there are quite a large number of the Gavilan Mancos wells that don't have those types of flow capacities but have flow capacities less than 200 barrels of oil per day.

If we look further to the east, we look at Canada Ojitos Unit wells, the ones that we have data for. We see that there are quite a large number of those wells that have very high flow capacities. We also show several other wells that are low flow capacity wells, which we are not sure if those -- if that's because those are observation wells or whether they are simply wells in areas that are not highly fractured.

In between those two areas we would like to note that there are several wells that have certain demonstrated low production capacities. For example, if we were to look in Township 26 Nort, 1 West, Section 20, the

Canada Ojitos Unit No. 22 has never produced. We assume that that is because it's not capable of producing.

We have, also in that same township in Section 32, the Canada Ojitos Unit No. 21. That well is currently shut in. It's last producing rate was 6 barrels a day. It had a cumulative production of 6000 barrels.

As we move directly south from that we see the Canada Ojitos Unit No. 24. That well is currently producing 4 barrels of oil per day. It's producing out of the A, B, and C Zones. It has a cumulative production of 300 barrels of oil.

We move further south to Sections 29 and 32. We -- there are two wells in there. There's the Canada Ojitos Unit No. 28, which is a very good well and produces in excess of 600 barrels a day.

There is a Canada Ojitos Unit No. 25, also produces in excess of 600 or appears to have capability in excess of 600 barrels a day.

These wells produce from the A, B, and C Zones.

Finally we move to the southwest, to Section 31 of 25 North, 1 West. We have Canada Ojitos Unit No. 31. That well is currently shut in. Its last recorded producing rate was 6 barrels a day after a cumulative production of 800 barrels of oil.

Q Now I think you stated that there are wells in the pool that produce or are capable of producing less than 200 barrels of oil per day.

A I, just looking at it, I would say that probably the majority of the wells in the Gavilan Mancos Pool fit that situation.

Q Would you expect wells that produce at less than 200 barrels a day to have 10 Darcy feet of reservoir transmissibility?

A Absolutely not.

Q Mr. Greer has suggested that many of the wells could reach payout in three months or less. Do you have any comment?

A In the calculations or the calculations that Mr. Greer presented, he assumed wells that were capable of producing 400 barrels a day under their revised allowable of 702 barrels a day under the statewide allowable, and he calculated very slight pay out times for those wells.

In practice there are only a limited number of wells in the Gavilan Mancos area that actually have that kind of demonstrated production capacity.

Q Would you now refer to the next map and explain what it shows? That's the gas/oil ratio map.

A The next map is a map of gas/oil ratios calculated based on December, 1986 production information for wells in the Gavilan Mancos Pool and adjoining tier of sections along the western tier of sections for West Puerto Chiquito.

In reviewing this informtion we would see once again the highest GORs indicated by the biggest circles and we, I think, would have our attention drawn to certain wells that are located in 25 North, 2 West, perhaps in Sections 15, 24, and 26. These wells are wells that produce with -- with GOR's generally in excess of 10,000 standard cubic feet per stock tank barrel.

The first thing that we might be tempted to conclude from this is that these are wells that are at the top of the structure, that we're having gas accumulate at the top of that structure and that we're having gas migration in the reservoir.

That is not our interpretation. We have wells that are equally high on structure interspersed with those wells that have the high gas/oil ratios. We have wells that are high on structure down in Sections 34 and 35 in Township 25 North, 2 West, that are very low in gas/oil ratio performance. It does not appear to us to be so much a matter of the structural elevation as it is perhaps more a matter of well productivity, of well quality.

The wells that are in Section 34 and 35, many of those tend to be some very good wells. Some of the wells that are up in the area where we have the larger circles are low productivity wells.

Moving then to the northeast area around the Mallon wells in Section 1, we see several of those wells with reasonably low GOR's, reasonably high productivity wells in that area.

We in part take this information to, you know, to conclude that there -- the gas/oil ratios are in part associated more with low productivity than they are with structural elevation.

Q If I understand you correctly, are you saying that there are wells low on structure that are producing at GOR's higher than wells high on structure?

A That's correct.

MR. KELLAHIN: Mr. Chairman, I have resisted as long as I can. Mr. Lopez has told us at the beginning of the day that he was going to let his witnesses testify and yet every time he asks a question he testifies, he characterizes the testimony of the witness and then asks him to answer yes.

That's not appropriate direct examination and I can't stand it any longer.

MR. LEMAY: Thank you, Mr. Kellahin, we all have different styles. I think Mr. Lopez can ask the witness, I didn't catch any leading there. I think he --

MR. KELLAHIN: You didn't? I'm sorry.

MR. LEMAY: I just thought he was trying to move things along, but --

MR. KELLAHIN: All right, sir.

MR. LEMAY: -- if you would just ask the question --

MR. LOPEZ: I will watch that, Mr. Chairman. I'll be glad to watch that.

MR. LEMAY: We'll appreciate it, Mr. Lopez. Thank you.

Q Let me ask you another question. Are some of the lower GOR wells producing at higher rates and vice versa?

A Yes, they are.

MR. LEMAY: Mr. Lopez, I thought that was the essence of Mr. Kellahin's objection.

MR. LOPEZ: I just wanted to make sure (unclear).

MR. LEMAY: I think you've (unclear) it.

Q Now, Mr. Hueni, I'd like you to refer to what has been -- or the next map, map 6, which I think is identified as a status map, and explain what it shows.

A Okay. Figure 6, which we've titled as a Status Map, is our estimation of which wells are being affected by the current restricted allowable condition of the reservoir; which wells are producing at capacity. This information is taken based on the latest month's oil and gas production reported to the state, as well as the number of days on production.

So, for example, if we see a well that has reported -- that's been on production for 31 days, it hasn't produced its maximum gas allowable or maximum oil allowable, we've concluded that that well is a limited capacity well.

On the other hand, if we see a well that has produced for perhaps only 15 days and it's produced a volume equivalent to its monthly gas allowable, oil allowable, then we conclude that that well was being affected by the production restricton.

Once again we are presenting this information as an indication of a variability in well quality. We have several wells which appear to be capacity wells. We have them somewhat interspersed with wells that are allowable limited wells. Certain of the allowable limited wells -- well --

Q Okay, are there -- are there a significant number of wells producing at the reduced allowable?

A Yes, there are a significant that are affected by the reduced allowable. Those are indicated by the red squares.

Wells that are producing at capacity, as we would estimate it, are indicated by green circles, and certain wells appear to be, their capacities and their allowables, it's just quite difficult to tell whether they -- they appear to be almost synonymous in tha sense, their capacity is their allowable, and those are the wells that we've indicated by the yellow triangles. Certainly this is based on available data and doesn't necessarily take into account wells that may be choked back on which we have no information about the fact that they are indeed choked back.

Q Do you believe that the wells that are operating at capacity as shown in the green on the map exhibit 10 Darcy feet transmissibility?

A No, I don't.

Q Now let's turn back to Figures 12 and 13 under Tab 2 and I'd like you to explain what these two figures are.

A When we began our study, one of the things that we -- that we wanted to do was to determine if there was any kind of migration that was occurring laterally across the field. By migration I mean gas migration such that gas would be tending to move to the structurally highest parts of the Gavilan Mancos Pool.

As a consequence one of the statistical plots that we made was a plot of the December gas/oil ratio production versus the elevation of the Niobrara A, the Niobrara A as mapped by Mr. Emmendorfer in a preceding exhibit.

And so we have wells in the Gavilan Mancos Pool with tops recorded between looks like about +250 up as high as about +600 feet that have production GOR's recorded for 1986.

That information is reported on on this particular plot. We've shown on the scale a plot -- a scale that goes from zero up to 40,000 standard cubic feet per stock tank barrel.

We see a couple wells that are very high in their gas/oil ratio performance. Those wells are in the range of 5-to-600 feet above sea level, and if those were the only data points that we had, we might conclude that yes, indeed, the gas was migrating to the upper part of the structure. So we look down and we see that also in that range, 5-to-600 feet above sea level, there are many, many wells that are operating at gas/oil ratios that are about the same as gas/oil ratios of the wells that are deeper down in the structure.

We had looked at these individual wells and we had concluded that the majority of the wells that showed very high gas/oil ratio behavior are wells that have very limited production capacities.

So once again, as we mentioned before on the gas/oil ratio plot, the presence of some high gas/oil ratio production in our minds does not suggest that we're forming any kind of secondary gas cap or gas migration; it suggests simply that we have some poor producers along the top of the Gavilan structure.

I might -- this is Figure 12. Figure 13 is an expanded portion of the scale of this same graph for those wells that had gas/oil ratios in the range of zero to 10,000, and I think when we look at that that once again we don't derive any kind of statistical correlation between the gas/oil ratio in December, anyway, and the structural elevation of the well.

Q Does this tell us anything about the lateral movement of gas throughout the reservoir?

A Well, we believe that -- we believe that it indicates that there is hoizontal migration of gas across the field such that it's accumulating at the top of the structure at this time.

Q We've now looked at poolwide production performance and individual well production performance. Could you now look at individual zone or interval performance, and in this connection I refer you to Figures 14 through 16, and would ask you to explain what these show.

A In performing this study and trying to get the best understanding that we could of the Canada Ojitos Unit reservoir, realizing that in the last hearing there was certainly -- certainly some unknowns regarding the productive interval, we encouraged a certain number of individual zone production tests to be run, and the three that were run that we have access to are shown on the next three plots, Figures 14, 15, and 16. These individual zone production plots were run on the Mobil Lindrith B-73 Well. It as tested separately in the C Zone beginning March 6th, 1987, and produced at the stabilized rate -- well, a rate stabilized for a period of about 13 days, of 10 barrels of oil per day.

The second well that was tested in the C Zone was the Mallon Davis Federal Well, located in Section 3 of 25 North, 2 West. This well when it was tested in the C Zone produced at rates generally one barrel a day or less for a 20-day period beginning January 3rd, 1987.

This well has also been tested in the A and B and appears to be a noncommercial well producing from the A and B at 5 barrels of oil per day.

The third well was the Mallon Fisher Well located in Section 2 of 25 North, 2 West, and this particular graph has two typographical errors in it.

First, at the bottom fo production plot we indicate production began November 3rd, 1987. Obviously that should be November 3rd, 1986.

And also after about 21 days we indicate that the Niobrara A and C were open. That is really the Niobrara A and B were open.

So the C production from the Fisher well occurred in a period of 22 days -- or a 22-day period beginning November 3rd, 1986. In this case it was a somewhat erratic production that averaged about 25 barrels of oil per day over that period.

When the Niobrara A and B were put on production the production increased up to rates in excess of 400 barrels of oil per day.

Q Is there any other information that provides us fluid flow out of the individual zones, and in this connection I refer you to, first, Figure 17.

A Also looking at where the production was coming from there have been several production logs that have been run recently in the Gavilan Mancos Pool and what we've tried to do is incorporated some of the -- some of these as exhibits, begining with Figure 17, which is a production log that was run on the Marauder No. 1, July 24th, 1986. It was run by Mesa Grande. It is what we call a capacitance survey combined with a temperature survey.

Q Where is the Marauder and for the Chairman and Commission's benefit, we still have Mr. Emmendorfer up at the structure map pointing out these individual wells and their locations.

A Right. The Marauder is located, I believe, in Section 7, Section 8, I'm sorry, Section 8, Township 25 North, 2 West.

This particular well, the capacitance survey, change in capacitance indicates a change in the fluid column of the wellbore, the capacitance as it -- the capacitance curve as it shifts to the left indicates a change from gas in the wellbore to liquid in the wellbore.

From this exhibit we see that there is an abrupt change that occurs about 7,111 feet, which we've designated as the lowest point of gas entry. This corresonds basically with the bottom of the A Zone. The top of the A Zone is located at about 7,050 feet. The top of the C Zone is located down in the range of about 7,230 feet and is indicated by the profile on the temperature log. There is no indication of significant fluid entry in that -- that particular region.

Q Would you refer to the next figure and explain what it shows?

A Figure 18 are the production log results previously referred to by Mr. Roe for the Homestead Ranch

No. 2 Well. We have included a similar section of the production log showing the spinner surveys indicated on the bottom of the graph and the fluid density survey is indicated also on the bottom of the graph, and from this particular graph we note, as Mr. Roe did, that there was a major point of gas and fluid entry that occurred at approximately 6,770 feet where we had a considerable amount of gas entering, as well as oil entering.

We see a slight amount of fluid entry below that point. Once again we would not consider it very significant, the amount of fluid entry below that point, particularly down in the C zone, to be particularly significant.

Q And Figure 19.

A Figure 19 is the production log results run on the Benson-Montin-Greer Canada Ojitos Unit F No. 30, which is located in Section 30 of Township 25 North, 1 West. That particular production log is unique of all the production logs we've run, televiewer surveys that we've taken, individual zone tests that we've made, this is the only well that we've noted that has had demonstrated significant production out of the C Zone. In this case this well, which I believe was producing in excess of 400 barrels a day, records approximately 83 to 85 percent of the oil coming from the C Zone. It also records about 15 percent of the oil production coming from the A Zone, and it indicates that essentially, well, the vast majority of gas is also coming from the A Zone, as well, the top perforation in the A Zone.

Q And would you refer to Figure 20 and explain that?

A Figure 20 is a production log run on another Canada Ojitos Unit well, the Benson-Montin-Greer Canada Ojitos Unit Well No. N-31, located in Section 31 of Township 26 North, Range 1 West.

This particular production log as opposed to the preceding log, indicates essentially no production coming from the C Zone, or at least very minor C Zone oil production.

It shows oil contribution from the B Zone and it shows a considerable amount of oil contribution coming -- the majority of the oil contribution coming from the A Zone.

It also shows that essentially all of the A Zone, or all of the gas that's being produced by this well is being produced out of the top perforation in the A Zone.

Q And then Figure 21.

A Figure 21 is the final production log information that we had available to us. This production log was run on the Mobil Lindrith B-37 Well in March -- well, on March 20th of 1987.

What we have on the lefthand side of that particular log summary are the perforations, the points of fluid entry, and then on the righthand side we have a column that's designated percent gas and percent oil, and what we see is, we see a high percentage gas for down to a depth of about 6,713 feet, a moderate oil percentage, and then we pick up in oil percentage below that and we -- we have a diminished percent gas.

Q What can we conclude from all this information you've just presented us?

A Well, once again the first thin we wanted to do in doing this study is we wanted to try and gain some sort of physical understanding of how the reservoir was performing.

From the individual zone tests, from the production logs, from the televiewer information, we have concluded that in the Gavilan Mancos Pool that the C Zone is at best minimally productive.

The second thing we've concluded is that where -- for the majority of the wells that we have information on, that the production that's coming into the wellbore generally shows that the gas is coming in through the highest set of perforations that are open to the wellbore. It is not coming in through all the perforations.

Q I think we've now talked about production performance, and we've looked at individual zone perforance. Is there any other data that you've examined that relates to reservoir performance, and I would ask you to refer to the next Figure 22.

A Figure 22, Figure 22 is a plot of recorded pressure information plotted versus time at which the pressures were recorded. We have the individual wells on which pressure surveys were done recorded according to different symbols and different colors. We have a legend that's shown on that graph.

We see a -- incidentally, the scale on this runs from zero psi to 2000 psi, whereas the preceding -- one of the preceding exhibits presented by Mr. Roe had a very expanded scale that ended at a pressure of 1,040.

We see a pressure trend for the wells in general. Many of the wells show very similar pressures. These pressures represent in some cases the results of pressure build-up surveys; in other cases the result of statis pressure surveys.

We have two points that are sort of on the upper righthand portion of the graph sort of off by themselves, maybe upper lefthand portion if you're looking the figure vertically -- if your paper is held up vertically. Those two points represent pressures taken in the Davis Well, Mallon Davis Well, located in Section 3 of

25 North, 2 West, during testing operations in the C Zone.

There is obviously some concern that this follows a frac job, that the reservoir at this point in time may be supercharged. On the other hand at this point in time we're not sure whether that represents true C Zone pressure or whether it is just simply the effect of supercharging.

In subsequent calculations that we've done we have taken the trend in pressures that we've shown on this particular plot, all of which were reported to a datum pressure of plus 370 feet above sea level, and we have used a trend line average through those points in performing several additional calculations.

Q Why is the pressure declining more rapidly since 1985?

A Well, I think it's very simply that we've had an increased rate of depletion from the field. Later on we will be presenting the same pressure information versus cumulative withdrawals taken from the field and when we take into account the fact that withdrawals have increased, the pressure decline has not been as dramatically affected as it appears in the pressure versus time plot.

Q Would this decline in pressure seem abrupt if it were plotted against cumulative oil production?

A No, no, it wouldn't.

Q The performance data that you've reviewed that the C Zone is marginally productive and that the majority of the production is derived from the A and B Zones, Mr. Greer has stated that you previously testified that the production in the Gavilan Mancos Pool was derived from a 600-foot interval, would you care to comment about that?

A Yes, I would. All -- when we did our first study in August of this past year there was not nearly the amount of testing that had been done in the Gavilan Mancos area, which was available for interpretation.

In order ot perform calculations that determined how fast gas and oil might segregate within the Gavilan Mancos Pool, we need to have some estimate of vertical permeability and in order to make an estimate of vertical permeability based on pressure build-up surveys that we had analyzed, it was necessary for us to assume a thickness value.

Now, if we assume a thickness value that is the maximum, then we calculate out the minimum permeability value, vertical permeability value, and consequently, when we use that in our calculations, we result in the most -- in a conservative answer, an answer that wouldn't do damage to the reservoir.

So when we said that we used a 600-foot interval, we were doing -- we were using that number not because we necessarily knew that the flow was coming out of a 600-foot interval, but so that we would have an answer that would certainly not be something that could cause damage to the reservoir, and what I'd like to quote is section or is a part of the transcript in which I discussed that, stating simply that we used a 600-foot interval as perhaps the maximum thickness that we saw production -- productive out there in order to arrive at a permeability. By dividing by 600 feet we ended up with a lower permeability estimate than we would of had we used, say, 200 feet or 300 feet. We frankly are not sure what the overall producing interval thickness is ourselves, but we felt that we would err on the conservative side, get a lower permeability, if we used the maximum thickness that is typically perforated by many operators out there.

Q What page is that of the August transcript?

A That is Page 130 of the August transcript.

Q One final question with respect to this section.

The pressure decline that you've described, what is it indicative of?

A Well, if we refer to Figure 22, we see a rapid pressure versus -- pressure versus time decline. We also see a decline when we plot pressure versus cumulative production, and what our analysis shows, and which we had proved later on, that this is simply the fact that we are depleting a reservoir that is not large in size. We are dealing with a dual porosity system. There is not a high oil content that we have to work with. There's not a large amount of oil in place. We are -- we have high productivities because we do have a fracture system and consequently, as we might expect, the pressure is going to drop down, down rapidly because we have a limited amount of oil in place to work with.

MR. LOPEZ: Mr. Chairman, I think this concludes our testimony with respect to Section 2 of the report and this might be a good time to take a break if we're going to go on to Section 3, or on at all.

MR. LEMAY: Okay, we'll take a 13 minute break.

(Thereupon a 13 minute recess was taken.)

MR. LEMAY: We'll continue with direct examination -- direct testimony, Mr. Lopez.

MR. LOPEZ: Thank you, Mr. Chairman.

Q Mr. Hueni, I think before you provided us with performance information that was available for analysis. Could you now tell us what the next phase of your study was.

A The next phase of our study was to attempt to describe the physical characteristics of the Gavilan Mancos Pool. These characteristics, when we then analyzed for field performance, should give us performance consistent with what's been observed.

So the next phase of our investigation was description of reservoir characteristics.

Q Would you care to comment on the type of flow system we're dealing with, and in this connection I would refer you to Figure 23 under Section 4.

A Was that --

Q Or under Section 3.

A After a considerable amount of study and investigating the characteristics of other types of flow systems, such as single porosity systems, with single porosity representing either a fracture system present in the reservoir or investigating a single porosity system where matrix was the only type of rock present in the reservoir, we have arrived at the conclusion that what we're dealing with is a dual porosity system, and this system is what we call a system that consists of a high capacity set of fractures combined with a low flow capacity matrix.

Now, by matrix, we once again don't use perhaps the classical intergranular definition of matrix, although that may indeed be a part of the matrix component. Matrix is also taken to include microfractures as well as low capacity or low permeability fractures that are just much lower permeability than high -- high capacity fractures.

Figure 23 is a schematic of the type of reservoir rock flow system that a dual porosity system is set up to try and describe. This particular figure is taken from a paper published by Warren and Root that describes dual porosity system. This particular figure shows a cube of reservoir rock that contains, obviously, a very high capacity fracture, which is shown intersecting the cube.

It also contains some vugular porosity, which in the case of the Gavilan Mancos Pool we don't -- don't see being present here.

It also contains some matrix material which is going to be much lower flow capacity than the -- than the high capacity fracture system, and it also contains at the very top, shows more or less a crack or a low capacity fracture, as well.

Now the importance from our standpoint, from the engineering standpoint, the important distinction is not one based on the type of porosity, whether we're dealing with intergranular porosity or a microfracture type porosity, it's simply that we have two different flow capacity systems that are present in the reservoir.

We have a high capacity flow system. We have a low capacity flow system, and that is -- that is a parameter that we identify when we talk about a dual porosity system.

Q Do you wish to comment further on the rock properties and in connection therewith discuss what you understood Mr. Greer to view the tight block system in the Gavilan Mancos? (sic)

A Right. Yes. We have handed out under a tab thats marked "Other Exhibits" a quote from a paper that was published by Mr. Greer along with Mr. Gorham and Mr. Woodward, Mr. Callender, titled Fracture Permeability in Cretaceous Rocks of the San Juan Basin.

It has a section in there that discusses drainage of tight fracture blocks and it makes note, as we've highlighted, "... a substantial amount of oil might be contained in the low permeability fracture blocks..." and just stopping it at that point, that is simply the same type of system that we are trying to describe with our dual porosity model, that we have two different types of rocks, one a high capacity fracture system through which flow can occur quite rapidly, and then a second, a low capacity type system which feeds into that higher capacity system and then through which fluids can move to the wellbore.

Q Before we go any further, there's been considerable discussion of the different types of producing mechanisms in the Gavilan Mancos Pool. Since it's possible that not everyone is not real sophisticated regarding these concepts, would you take a moment to further explain these to me and in this connection I would refer to Exhibits 24 through 28?

A Right. We're going to look at Figures 24 through 28, which presents some schematics of the different types of flow systems that we might expect to encounter in a reservoir and we -- what we're trying to do is decide which of the types of flow systems that we have pictured here are we really seeing prevalent in the Gavilan Mancos Pool.

Incidentally, Figures 27 and 28 are not numbered, they just follow sequentially after Figure 26.

What I'd like to look at first is Figure 24. It is a schematic of a single porosity system. This is the type of porosity system that it's my understanding has been described by the Sun simulation model and it is a system where the pore space in the rock is basically all associated with the fracture system itself, and initially that pore space may be filled up with oil, which we've designated by the green color, and then as we withdraw oil from that block, and we drop the pressure below the point at which gas comes out of solution, that gas, because of the high capacity of the fracture system and given vertical communication, then that gas will just by the density difference segregate to the top of the system itself, so the gas will overlie the oil in the fracture system itself.

And this is not only a single porosity system showing a fracture, but it is also showing what we call gas segregation vertically within the producing interval.

Now this is the way the reservoir, a vertical section of the rock might look early in the life of the reservoir where we have gas on top of the oil. The gas will mvoe to the wellbore at one rate; the oil will move at a different rate.

The second, the second schematic, which is Figure 25, is the same single porosity system except now we are much later in the life of the field. We will have the gas once again having segregated to the top, the oil at the bottom, and we will have oil flowing out of that bottom section more or less unimpeded by the presence of gas and gas flowing out of the top section more or less unimpeded by the flow of oil.

Once again this is gas segregation and this represents later in the life of the producing reservoir. The gas/oil ratio performance for this type of reservoir is not going to be the rapidly increasing gas/oil ratios that we expect to see in a solution gas drive field. this will be a much more moderate increase in gas/oil ratio performance and we'll demonstrate that later on.

The next figure, Figure 26, is intended to represent the same single porosity system but this is a system that is produced so fast that the gas is not given sufficient time to migrate to the top of the -- top of the formation, so that rather than having this opportunity to move vertically upward, it is produced rapidly horizontally across the system and then comes out of the producing interval uniformly, more or less uniformly distributed across the vertical interval.

We show that both oil and gas are flowing concurrently at the same point in the reservoir and the fact that we have both oil and gas flowing at that point, the flow, the presence of both fluids impedes the flow of the individual fluids and the presence of gas tends to impede the flow of oil more, so that the gas slows down the oil, the gas moves relatively a little bit faster, and in this kind of system we expect to see a rapid increase in gas/oil ratio.

So this would be a system that is a solution gas drive system, single porosity, and we do not see gas segregation. So what we tried to draw here, first the single porosity model, what it looks like; second, the difference between gas segregation and solution gas drive.

Now we'd like to turn to Figure 27. This figure is more the type of system that we believe exists in the Gavilan Mancos Pool. We believe it's a much ore complex system than just simple, simple fractures.

This is the representation of a dual porosity system. The individual cubes that we see there represent what we call the matrix, or what we'll just say is a low capacity flow system. Fluid will not flow readily out of those -- out of those individual cubes.

Separating the cubes sort of in an idealized fashion both in a horizontal sense and a vertical sense, are high capacity fractures through which flow to the wellbore occurs. The flow, once again, is from the matrix into the high capacity fracture system and then through that high capacity fracture system to the wellbore.

So what other people have talked about as drainage in tight blocks is really the expelling of oil out of matrix into the high capacity fracture, then moving to the wellbore itself.

What we've shown in Figure 27 is a system as it might initially exist when the pressure is above the bubble point pressure all gas is contained dissolved in the oil.

We've represented the oil by the green dots as contained in the matrix to indicate that it is perhaps associated with some type of matrix porosity and then we filled fractures with oil indicated by the green.

As we start to produce a system like this, we see what -- very likely what will happen and what we believe is happening in the Gavilan Mancos Pool, and that is Figure 28.

As we produce this reservoir we drop to pressures that are less than the bubble point pressure and gas will no longer be completely dissolved in the oil so that we will have the presence of a free gas phase in the reservoir. That free gas phase will exist both in the fracture system as well as in the matrix system.

The matrix system is very low capacity. It doesn't have a great deal of flow capacity, so it is not going to segregate within the individual blocks. Basically what we're going to form is what we call a gas saturation, where we have a certain percentage of the pore space occupied by -- by gas and a fraction are occupied by oil. As the pressure drops in this system oil and gas are expelled from the matrix flowing into the high capacity flow system and then as it enters the high capacity flow system, because of the large amount of vertical transmissibility, at least within the producing interval, it will -- gas will segregate vertically to the top of the system.

Now one of the reasons we say that we have a dual porosity system, or one of the evidences that we have that we have gas segregation, is that we do have gas flow occurring into the top perforations in the wellbore, indicating that the gas is segregating to the top, top of the system and the oil is staying at the bottom of the system.

One of the points that we would make is that there is no way that the oil and gas can move out of the matrix blocks unless the pressure in the fracture system is less than the pressure in the matrix blocks. There is no pressure differential to drive that with unless that occurs.

So in order to realize maximum benefit from the low permeability matrix system, we end up having to -- having to have a pressure drop. Then once again, when we get into the high capacity flow system, we have segregation occurring and when we -- when the fluid reaches the wellbore the gas is more than likely principally segregated on top of the oil.

The distance that we're talking about, we need to keep in mind that we're talking about fairly large horizontal distances here between wells. We're figuring 20-

acre spacing is 2000 feet. That gives quite an opportunity in oil moving that -- that distance to a wellbore, it also gives it a good opportunity for gas to move vertically upward to the upper reaches of whatever the continuous interval of fracture is.

Q One of the other reasons you indicate that we have a dual porosity system is that you ran some foregoing compressibility studies. Would you comment about this, please?

A Yes. Well, I'd like to say that we do believe that we have a dual porosity system. We believe it not on the basis of any one piece of evidence. We have -- we consier several pieces of evidence that include the core descriptive studies of -- that have been described previously by Mr. Faulhaber; by the information presented previously by Mr. Emmendorfer; we also have the televiewer logs which indicate that we have a high intensity fracture system which would allow, then, even very tight matrix to communicate with these fractures.

We have a somewhat analogous description of a dual porosity system by Mr. Greer, and then in addition to that, we have -- we have some tests that were -- we commissioned Terra Tek Laboratories in Salt Lake City to run for us, and that information is presented in Appendix B.

One of the reasons that we asked Terra

Tek to complete this study is that we did not feel that we had necessarily any -- any highly reliable values for rock compressibility, particularly rock compressibility that might include a fracture, and rock compressibility, while many authors tend to think that that's not an important quantity, in a system that is a fractured system, it can become extremely important. We wanted to be sure that the tests were carried out properly. The first letter under the Terra Tek report is a letter addressed to me from the project engineer describing the procedure that they followed in performing the pore volume compressibility test.

And the gist of this letter is that they exercised caution to make sure that none of the formation was damaged, that they didn't create any hydration cracks in the core samples before they -- they actually tested them.

They also make the point that some of the results that they present here in terms of answers are going to be on the low side in terms of the values of rock compressibilities.

One of the things that we're going to see in a second is that rock compressibility very well is on the order of ten times greater than is -- than any value that's ever been used up to this point in the Gavilan area.

The first letter, as I said before, presents a summary of the preparation, core preparation, and some miscellaneous comments with respect to their pore volume compressibility tests.

Following that is a report which they submitted to us and this report deals with three, what we call pore volume compressibility measurements, and these three pore volume compressibility measurements were run. Two were full core measurements, one run on a core that was primarily a silty shale and sand that occurred in the B Zone, and that is the Number 1 core described under the introduction to the report, Number 1, Full Diameter Fractured Core, Silty Shale and Sand, depth 7,087 feet out of the Davis, Mallon Davis Well. that is a B Zone core.

The second Full Diameter Fractured Core occurred in the shale zone. Depthwise it was at 7221, which represented an interval in the C Zone.

Finally they ran a core plug sample to determine matrix pore volume compressibility from a depth of 73 -- or 7,338.7 feet, and this is also sort of in the lower part of the C section.

Under test procedures, a little bit further down that page, about a quarter of the way from the bottom, it talks about number of hours required to flow a volume through the sand core at a very low injection pressure of 5 psi, indicated high permeability. This was a B Zone core.

The second sample, which was C Zone, cleaned up after 120 cc's, which two days were required to flow this volume at 75 psi, indicating much lower permeability in the C section.

Now, they then went through and conducted the test and what they do in a test like this is they saturate the samples with fluid and then they exert a hydrostatic pressure, they put a hydrosttic pressure on the outside of the sample, and as they put a higher pressure on that sample, then it causes fluid to be extruded, or ot extruded, but I guess they use the word (not understood) from the sample; in other words, discharged from the sample, and this is something they measure.

Now the significance of this kind of test is that it is run at high pressures, high net overburden pressures, representing in situ conditions in the reservoir, and we would conclude that if we see flow through the system at these kind of net overburden conditions, if even though we may have a low porosity, then we would have to consider that that is evidence that matrix flow is actually occurring, can actually occur at the pressure levels that occur within the reservoir itself.

So they carried out these tests and I'll show you the results of them in just a second.

Under the remarks and conclusions,

though, while we're looking at this -- this section, the very last remark and conclusion on the final page states, "Last, but not least, if the samples are representing the reservoir, we may conclude that fracture and matrix porosity are of the same order of magnitude, and both less than 3 percent. Very likely the fracture porosity is less than that of the matrix. Matrix contribution to the production of oil will be noticeable provided the fracture system is well developed and relatively dense."

Now, this we consider to be a fairly significant conclusion; came from Terra Tek. We recognized Terra Tek in another place. It also reported that there was no matrix porosity, so in order to feel comfortable with the results that Terra Tek had provided us, we asked Amoco to take a look at the petrographic work that had been done by Terra Tek and to provide us with their conclusions.

And the Amoco letter documenting their conclusions follows the Terra Tek report in the last two pages. This letter was sent to me by John Thomas, the regional petrologist for Amoco after studying samples from cores from the Amoco Jicarilla Apache A-118 No. 14, which is near the northeast Ojito Gallup Dakota Pool, after studying the Mallon Davis Federal 3-15 information, and after studying thin sections from the Mobil Lindrith B-34 Well, as well.

This letter describes the matrix porosity system which Mr. Thomas notes in this particular rock and in the final paragraph he notes, "In summary I do not believe the Gallup Mancos reservoir in the Gavilan and West Puerto Chiquito Pools is a simple megafracture-drainage network. The microfracture and intergranular pore spaces must be interconnected with the megafractures."

So once again reviewing the pore compressibility information, we concluded that we had matrix contribution and that we could obtain -- we could obtain flow from the matrix at reservoir conditions.

Now, if I could ask you to turn back to the --

Q Excuse me, Mr. Hueni, before you leave that letter, I think -- is it not true that there is a typo on the second page, the Mobil Lindrith Unit B, it's B-38 not B-34.

A That's correct. That's correct. I'm sorry. That's right. We -- Mr. Thomas was sent approximately 40 thin section samples from Mobil to investigate and those were from the B-38 Well.

Q Okay, I'm sorry. Please continue.

A I'd like to return, then, to Section 3 of the report and specifically to Figures 29, 30, and 31.

Figure 29 are the results obtained from

the Terra Tek report, reflecting the poor compressibility mesurements on the full core sample, the sand sample, that occurred at a depth of 7,087.

The second, or the next figure, which would be Figure 30, is the full core shale sample, and then the final one is the core plug results.

Now, what we have, if we look at Figure 29, is we show on the lefthand column something we call effective stress and what effective stress means, it is the difference between the external pressures exerted on a test cell and the pore pressured of the fluid within the test cell.

So in other words, we are simulating a large amount of overburden pressure by doing this type of test, and as we increase the overburden pressure, what that has to do is it has to reduce the pore volume of the rock and it has to causes volume to be what we call eluded from the sample, giving rise to the incremental and cumulative columns that we see on the -- on the test, or on the columns 2 and 3 of that.

From that we can calculate what we call compressibility. Compressibility is the rate at which the rock volume will change per unit volume of rock per psi pressure change, and those numbers, then, are shown as the hydrostatic compressibility and also knowing the initial porosity of the system, which the sand sample was 2.04 percent, we could see then how the porosity diminishes with increasing overburden as would be reflected in the reservoir itself.

So in this case at the 4200 psi effective stress level, the porosity has diminished from 2 percent down to 1.45 percent.

The hydrostatic compressibility values that we see down at the 4,200 range is 50 times 10 to the -6 in reciprocal psi units. This value is -- the values that we've heard quoted previously for -- well, the value that was used in the sun study, simulation study, was a value of 10. The value that Mr. Greer quoted was a value of, I believe, and I hope I'm not misquoting this, in the range of 6 to 10.

We have values of 50, and if you recall back to the letter of Terra Tek, they said that this value would be pessimistic. In other words, this is going to be on the low side. The true compressibility of the system is going to be greater than this and in our estimation after doing several modeling runs trying to obtain a match of performance, we believe it's on the order of 100 times 10 to the -6, which is a value that is approximately 10 times the values that have traditionally been used in this area.

I might add that there are also correlations that are available to estimate fracture compressibility and those correlations give numbers similar to the results of the Terra Tek report, so we have no reason to necessarily question them.

If I could turn, then, skip over the shale sample, because once again we don't necessarily believe that the C Zone is going to be productive, and turn to Figure 31, what I have is the rock compressibility informton for core plug. Now this core plug was selected so that we didn't have any kind of fracturing and what we did is we ran this test from an effective stress level of 300 up to 6000 psi, and what we saw, that even at 6000 psi we were still squeezing fluid out of the -- out of the pore space of the core. Now this is -- this is once again reflective of reservoir conditions and it very clearly shows that fluid will flow out of a -- out of this matrix type rock at conditions that are reflective of reservoir conditions.

We show on here compressibility values and on compressibility values for the core sample, we move across -- well, we could move down to the effective stress level of 6000 and across to the fifth column, which is designated as uniaxial compressibility, and we would see that the value of compressibility in this -- on this particular sample was on the order of 135 times 10 to the -6, a value ten times what has traditionally been used in the Gav ilan Mancos Pool.

So both the fracture system, which we looked at previously, which -- which we said we believe is on the order of 100, as well as the matrix, both of these numbers are very large.

Now we can also see what happens to the matrix itself as it is subjected to increasing overburden pressure as shown by the porosity column on the far right. At 300 pounds net overburden conditions we have 2.6 percent porosity. As we go to higher and higher net overburden conditions, the porosity diminishes considerably. What we believe is the effective stress level in the Gavilan Mancos Pool at the time it was discovered is on the order of 5,200 psi, and if we read across that 5.200 psi column, we would see that that 2.6 percent porosity rock probably has had its porosity diminished down perhaps to as low as 26-5 percent porosity.

So we recognize very well that in this study that we are dealing with in the matrix a very low porosity system. It's going to be a very tight porosity system, and consequentially it will not produce unless there are highly developed -- there's a highly developed high capacity fracture system in the vicinity of this particular type of rock.

Now, finally, the final comment that I'd like to make with respect to pore volume compressibility measurements is I'd like to make with reference to Page 3.5 of our report.

Q Would you want to skip over to Figure 32 and look at that?

A No, I didn't. I'm sorry, I apologize.

If we could look at Figure 32, then I'd like to look at Figure 3.5.

Figure 32 is the plug analysis presented from the Terra Tek study of the Mallon Davis core and this plug analysis reported several values of permeability and porosity for these different, these individual core plug samples. Many of them were not considered reliable due to dehydration cracks affecting permeability measurements. Those are noted in the third column from the lefthand side of the page with the notation 3, or the superscript 3. There are, however, several additional permeability and porosity values that are reflective of the -- of the matrix -- matrix, or the -- yes, of the matrix permeability and porosity.

Now, if we were to take the valid -- the readings that we consider more or less valid, then we would -- we could average out those twelve readings and we would come to a value for permeability of about .018 millidarcies from the core plug samples and we would come to a porosity reading of about 2.6 percent porosity.

Now, if we could turn to -- back to page 3.5, the question is how much is the permeability, this value that's already pretty small, the .018 millidarcies, how much is that reduced by putting -- subjecting the rock to some fairly high level of net overburden pressures reflecting the initial conditions of Gavilan.

And on Figure 3.5 the first thing I'd like to note is we show a formula and we show a formula that's been quoted before, sometimes not in its correct interpretation on the Gavilan Mancos Pool. The porosity is related to the cube root of permeability. This is true for a fracture system of fixed density and a fixed fracture density. And what we've assumed, and this, I think, is a fairly conservative assumption, that all of the porosity that's contained within the matrix is microfracture porosity and consequently what we've done is we've taken this cube root relationship, take the peremabilities that we've measured, first the value of Phi 1, the 2.6 value, is a value that we measured in the Terra Tek samples, the average of the twelve samples, and we've divided that by Phi 2, which is the .64 value that is the value at net overburden conditions reflecting the Terra Tek pore volume compressibility measurements, and then we've taken the value of K1 and that should read .018 milidarcies instead of .18. that needs to be corrected.

And we've corrected that, then, to the permeability that we show as K2, which is a value of .0003 millidarcies, or .3 of a microdarcy.

Now that is if we assumed this conservative relationship on cube root of permeability, that is the value of permeability that we would -- would have indicated from the core plug analysis.

Now we dont -- I think I need to make it clear that we dont necessarily believe that the matrix component in the Gavilan Mancos Pool is strictly this microfracture intergranular matrix that we may have measured in the core plug. We also suspect that there are going ot be fractures in that area that are going to be lower capacity fractures in this tremendus high capacity fracture system that we have.

And so the value that we have, this -- the value of the permeability that we have currently in our work, in our engineering work, is not quite as low as the type of matrix permeability that we are able to get more than sufficient flow out of the matrix and into the fracture system to duplicate the behavior of the Gavilan Mancos Pool.

Q What do all these pore volume compressibility measurements mean to us?

A Well, they mean -- they -- they tell us two things. They tell us first that the rock compressibility value that we should be using in our studies of Gavilan Mancos Pool is considerably higher than any of the values that we traditionally have used, at least to the best of my knowledge have been used in studies up to this point for this particular pool.

And the second thing it tells me is that there -- that there is matrix contribution. We have observed it. We see fluid flow into the matrix. We see fluid flow out of the matrix.

Q Mr. Hueni, I think you've now described the type of porosity and the rock compressibility information for Gavilan Mancos Pool. Could you now describe what you consider the permeability of the reservoir and go ahead?

A Yes, okay. Well, the next property that we tried to describe with respect to the Gavilan Mancos Pool was the permeability of that reservoir and rather than describe talking about permeability, it's probably easier to talk about what we call transmissibility. This is a term that other people that have presented testimoiny have used. It is the permeability thickness product, because all of us have a difficult time absolutely quantifying what the true producing thickness is of the producing interval.

We've heard testimony up to this point that there are wells that exhibit up to, I believe, as high as 49 Darcy feet of transmissibility and we've heard in previous testimony that interference test transmissibility values of 5 to 10 Darcy feet have been reported for the Canada Ojitos Unit.

We do not believe that those values are reasonable. We do not believe that they could have been reasonably obtained given behavior of a dual porosity system. We just don't think it fits.

We certainly don't think it fits the behavior of Gavilan Mancos Pool. We just don't see wells that produce at rates of 1-to-200 barrels a day having tens of darcies of permeability or of transmissibility.

We -- we have used a different type approach in calculating permeability or transmissibility. What we have done is we've attempted a twofold approach, one we have used the pressure build-up analysis performed on the various wells in the field. We've analyzed that pressure build-up analysis in many cases ourselves, using a type curve approach and using a Horner analysis approach, to determine the values of transmissibility for the various wells in the field.

The second approach we've used is an approach we call the psuedo steady state approach, which uses the demonstrated maximum flow capacities of the individual wells to determine what type of transmissibility is required in a radial flow sense for the fluid to flow in at a particular observed rate.

The types of observed rates that we used on individual wells were the types of observed rates that we plotted on the map that we presented that we've also hung on the side of the wall over there, which was the maximum oil rate map.

We find when we use the pressure build-up analysis and the flow approach, the steady state flow approach, we end up with what we think are fairly -- fairly comparable type values and values that are much more reasonable. They're not -- not on the order of tens of darcies. They are on the order of hundreds of millidarcies to maybe a Darcy foot. In some cases, and in many cases, it's down in the order of 50 millidarcy feet.

Q Would you now refer to Figure 33 ad 34 and explain that these show?

A Figures -- Figure 33 is a summary of several pressure build-up tests which we analyzed using a type curve analysis and using a Horner plot analysis. And then this presents the results of those tests.

The column on the left reflects the well name. There are seven tests that we -- that we analyzed. The test date, the oil rate, producing oil rate, are shown in the next two columns.

The values that we would like to focus on are under the type curve analysis, the column labeled kh, which is transmissibility.

Under the Horner plot analysis is the value of kh, which is also representative of transmissibility.

One of the things that we found from this type of analysis, and one of the problems that we have with some of the analysis that's been previously presented, is that in many cases no attempt is made to validate the proper portions of the build-up curve that should be used for determining this quantity that we designate as kh that is transmissibility.

The pressure build-up analysis represents effective permeability in a radial flow system. It averages out to some extent any kind of directional permeability. So if we have a very high permeability in one direction, then in the averaging process -- well, then the values that we see here would indicate that in the other direction, or the perpendicular direction to the high flow capacity direction, we have a much lower transmissibility.

The values that we obtained from the type curve analysis and the Horner plot analysis obviously do not agree exactly but they are reasonably consistent and they are certainly of an order of magnitude much large -- much smaller than has been previously presented.

One of the build-up analysis curves that we analyzed was the Rucker Lake No. 2. That is the test that's listed first on Figure 33. The build-up curve information is presented in Figure 34. This is what is known as a Horner plot. Along the bottom of the plot we have something that is reflective of time, the amount of shut-in time compared to the producing time, and then as the shut-in time increases, the pressure builds up, and we have pressure as measured on the Y axis and we see this increase in pressure. We see it go up. We see it level off. We see it go up again.

The -- this separation or this dual straight line behavior is typical of -- typical of what we would call a non-homogeneous system test and it is one of the classical shapes that would be reflective of a dual porosity system. There are, I believe in all fairness we have to admit there are other reasons why you could have this particular type of shape, but dual porosity is one of the reasons that you can -- that you can reflect on that could be indicated by this shape.

So once again we see at least some indications in certain wells of dual porosity behavior based on the pressure build-up surveys.

Now, also discussing the subject of reservoir peremability, we are taking a steady state approach and what we've done is we've taken the observed oil production rates for individual wells, the maximum oil production rates as we've indicated on the map that we presented previously, and what we've done is we've related the amount of transmissibility required in order to obtain that kind of oil flow rate and this is -- we use what's called the pseudo steady state approach and what we've done is we've used a flow equation that -- that is -- that determines relationship of flow to transmissibility and we've used a drainage area of 320 acres. One of the comments that we have had previously is that pressure build-up analysis does not reflect the average properties of the reservoir. The pseudo steady state flow analysis has to reprsent the average properties of the reservoir because that is the demonstrated well flow capacity.

So what we have done is, and we showed this in Figure 35, is we've taken our psuedo steady state producing capacity, which we've plotted on the Y axis, and we've plotted it against the permeability thickness or the transmissibility value along the X axis, and we've assumed in this analysis that we have maximum producing drawdown in individual wells and that may be -- that may not always be a good assumption. I think we saw yesterday a case of some wells where we had very high flow rates with very low producing drawdowns in the case of the Canada Ojitos Unit 29 and 32, I believe, had very minimal drawdowns.

But certainly some of our capacity wells in the Gavilan area are being pumped off and do not have a substantial amount of back pressure against the formation.

This relationship says for that type of well that's producing at capacity if we observe the flow rate on the Y axis of 10 to the 2, which is 100 barrels a day, we would come across, intersect the line and then read downward and we would determine that we only need permeabilities on the order of 30 millidarcy feet in order to get that kind of flow rate.

200 barrel a day, we would go over a bit further. We'd see it was 60 millidarcy feet. We don't require the high transmissibilities in order to -- in order to see the capacity flow rates that we've seen on many of the Gavilan producing wells.

We -- the pseudo steady state approach is an approach based on a 320-acre drainage area. It reflects average flwo characteristics into a wellbore. Once again it averages out, perhaps, in directional permeability but once again if we can't identify the directional permeability, then we might have difficulty using -- taking advantage of high permeability in the reservoir in a particular direction because it would be offset by low permeability in the opposite direction.

We've compared our results in Figure 36 and Figure 36 is what we call Radial Flow & Pressure Build-up Derived -- that should be Transmissibilities, instead of m-i-s-c it should be m-i-s-s -- For a Portion of the Gavilan Field.

And what we've shown on here are three wells, the Native Son No. 2, the Native Son No. 1, and the Hawk Federal No. 2, and what we've tried to do is draw circles around these wells but our computer seems to want to draw elliptical shapes and that wasn't intentional. The radius of these circles are meant to designate a 320-acre drainage radius, and we can see then that these circles intersect a bit between the Native Son 2 and the Native Son 1 and the Hawk Federal No. 2, which are spaced a little bit closer than -- than a pure 320-acre drainage radius would suggest.

This -- these are the areas that we're measuring the transmissibility for with the pseudo steady state approach.

Assuming these wells are producing at capacity, which once again in not all cases is going to be a good assumption, we would calculate based on the observed maximum reserved flow rate from the Native Son No. 2, a transmissibility value of 250 millidarcy feet.

For the Native Son No. 1 from our steady state approach we would calculate 201 millidarcy feet, and we would compare that to what we got from our pressure build-up analysis, which is a value of 181. In other words, we're getting about the same answers both ways.

We're not getting two different answers.

And finally through the Hawk Federal we're getting values of 103 millidarcy feet.

We have concluded based on permeability that we do have variable permeability in the reservoir. This whole reservoir varies in a lot of its parameters and permeability is one of them and it's reflected by the variation in the producing rates that we've observed out of the -- out of the wells. There's a high degree of variability.

We do have some wells with good transmissibility values but we also have a large number with much poorer transmissibility values.

We've concluded that the pressure build-up analysis gives about the same answer as the pseudo steady state analysis and both of those answers are far less than values of several Darcy feet of transmissibility.

Q What are those answers?

A The -- well, the answers for transmissibility, we've shown for some of these individual wells in the range of 180 to 200 millidarcy feet.

In our simulation study we have used a value of 400 millidarcy feet. We have also tested our answers against 10 Darcy feet and we come up with to some extent the same answer.

Q In addition to peremability or transmissibility characteristics, I understand you also need to have some estimate for relative permeability characteristics, so first could you explain what relative permeability characteristics are and second, what values you used in your study?

A All right. Once again, we're trying to describe the reservoir. I can understand this would be tedious, it's a tedious description, but if we don't get the proper description of the reservoir, we aren't going to be able to duplicate performance and we're not going to be able to understand how the field will perform and we can't determine what the optimum depletion plan is. So, you know, we want to present our entire analysis here and the next part of it is this -- has to do with the subject of relative permeability.

Relative permeability is a factor that is applied against the -- what we call absolute permeability that we've just been discussing and it applies to instances where we have ore than one phase fluid flowing at a given point in the reservoir, so if we have oil and gas flowing at a point in the reservoir, the presence of both phases tends to interfere with the flow of each individual phase, and so the more gas that we have present in an area, the more the oil flow will be restricted.

Now in dealing with the dual porosity system we have to have relative permeability characteristics for both the fracture system as well as for what we call the matrix system, which is once again a combination of low capacity fractures, microfractures, and true -- true matrix.

These characteristics have not been determined in the laboratory on any -- on any core that I'm aware of in this particular area, so the best that we can do are to use industry guidelines that appear reasonable.

For the fracture system, we are dealing with a high capacity fracture system. Work by previous authors suggests it would be reasonable to use what are represented by straight line functions of relative permeability to saturation and these are shown in Figure 37.

If we looked at that we would see oil saturation fracturing. When we look over the far righthand scale, we'd see oil saturation being 100 percent and if we look then up at the term called Kro fracture, we would see it 100 percent. It intersects a value for relative permeability of 1. So if we have no gas present in the system, then it doesn't interfere at all with the absolute permeability and so we have -- that's what's indicated by a relative permeability of 1.

If the system is essentially entirely gas, then instead of an oil saturation of 1 we would have an oil saturation of zero and the relative permeability of the flow of oil would be zero. No oil is going to flow because there's none there, but it's not going to flow because the gas int4erferes with its ability to flow.

That's what relative permeability characteristics are. From the literature for a high capacity fracture system, we've used the straight line curves. We have also tested the high capacity fracture system and we found it to be relatively insensitive to the values that we use for relative permeability for the fracture system.

The matrix, on the other hand, has -- has a set of curves that are considerably different than the fracture. They are labeled by matrix. The oil relative permeability, you'll note will drop off quite quickly. it's anticipated it will drop off quite quickly as gas is evolved from the oil and occupies a portion of the pore space, and at the same time the flow capacity of the gas will increase, and we've shown those two curves by the Kro and Krg for the matrix.

Now we have modified those curves a bit, not a great deal but we've modified them a little bit in order to try and duplicate the observed performance of the

Gavilan Mancos Pool, and what we have on Figure 38 is some more relative permeability information.

What's plotted along the -- the X axis is total liquid saturation and what's plotted along the Y axis is the ratio of relative permeability to gas, the ratio of the relative permeability to gas divided by the relative permeability to oil, and the values that have traditionally been used for the Gavilan Mancos Pool, and they are totally arbitrarily selected, have been the values that are, well, the value that's shown by the dashed curve that also has an arrow going over to it that says "Curves used in calculations", but other values have been run, as well, as suggested perhaps by the other curves that are in place on the -- on this graph.

The curve that we have arrived at to describe this matrix system, from which we believe a large amount of flow is coming, is what we show as the Bergecon Model Curve, and I think the point to be made is that it does not reflect any radical departure for the matrix from curves previously used.

Q One of the other parts of a reservoir description is a description of the reservoir fluids. What is your opinion about the fluid properties of Gavilan, and in this connection would you refer to the Figure 39 and following?

A We have heard in some simulation study and we heard in the preceding hearing that the Canada Ojitos Unit fluid sample indicated a bubble point pressure in the order of 1500 psi; I think they used a value a little bit higher than that.

We have a logging pvt sample that is on the order of 1500 psi, as well.

In our previous study of the Gavilan Mancos Pool we had a very difficult time rationalizing the amount of gas that was coming from that pool, using that as a representative set of fluid properties, and in looking back at the pvt samples themselves, we believe that there is a high probability that the sample was not -- well, just by the nature of the sampling conditions, was not totally reflective of the -- of the reservoir conditions.

In our preceding hearing we -- we indicated that we thought the bubble point pressure might be 1770. We've revised that number, based on our study, down to a number of 1660, and to illustrate to you why be velieve that the bubble point pressure has to be greater than the 1500 psi pressure that other people are using, we have constructed a set of plots, and that's what we show in Figures 39 through 41 and those plots are plots of pressure versus gas/oil ratio.

Now, the source of our pressure test that we -- pressure test information that we refer in the reservoir performance section. At the point in time where we had a particular pressure measured, we could also go the field gas/oil ratio performance curve and determine the gas/oil ratio at that point. And so we can plot gas/oil ratio not as a function of time but strictly as a function of pressure.

We did that for the field as a whole, which we show on these figures as "Total all wells".

Q Greg, before you go ahead, just so everyone is staying with us, could you just explain what a bubble point pressure is?

A Okay. A bubble point pressure oil -- well, let me back up.

Oil contains a certain amount of gas dissolved in the oil and the amount of gas dissolved in the oil is dependent on the fluid composition of the gas and oil together. It's dependent on the reservoir pressure and the reservoir temperature. It's dependent on all those factors, and so if any of those factors change over an area, then a fluid sample from one area may not be reflective of a fluid sample from another area, and, in fact, we find many large reservoirs in the world where fluids vary in their properties even within the reservoir itself.

Now a bubble point pressure is that pressure that when -- if we start out at a very high pressure and we lower the pressure down to some particular -- to some specific lower pressure, we will see in that oil just the very first bubble coming out of solution in the oil, and that's what we call the bubble point pressure. It's the first point, it's the pressure at which the oil begins to bubble out of the -- at which gas begins to bubble out of the oil, and that, a little bit further, the significance of this is that when we review reservoir performances, if we don't understand what the correct reservoir properties are for the pool, we once again will tend to misinterpret the producing mechanisms in the pool.

So the bubble point pressure is that pressure as a reservoir pressure declines, is that pressure that will be reached eventually at which gas that is dissolved in the oil will begin to bubble out of the oil and form, then, a free gas phase within the reservoir.

Q All right. I thought that that would be helpful (inaudible)

A Okay, well, we plotted gas/oil ratio versus pressure for the field as a whole and for several of the three individual wells, and what we see for the field as a whole. if you can focus in Figure 39 on the circles, is we see that when we reach a pressure of aboout 1600 psi that the gas/oil ratio which had been running about 1000, begins to climb abruptly, and we see that behavior not only for the field as a whole, but if we compare it for the individual wells, Figure 39 we compared to the Full Sail No. 1, which is a well that's high on structure, if we compare it we see that the breakover point is also at about 1600 psi.

On Figure 40 for the Native Son No. 2 we see that the breakover point for the Native Son No. 2 was even higher than 1600 psi.

For the Rucker Lake No. 2 we see that the -- that the breakover point for the increasing GOR was also about 1600 psi, and from that we concluded that, from that type of information in conjunction with our simulation work, we've concluded that the bubble point pressure from the pvt sample in the Loddy is not representative because it will not duplicate that type of performance.

Q Could you explain what the breakover point is?

A The breakover point is that point on the pressure versus gas/oil ratio plot where the gas/oil ratio begins to increase dramatically with lower pressures, and that is true for Figures 39, 40, and 41, that in all cases at abot 1600 psi the GOR began to increase significantly.

Q Would you now refer to Figure 42 and explain what this shows, please?

A Yes, okay. Figure 42 is the same type of plot. It's a plot of gas/oil ratio lotted against reservoir pressure as measured by our pressure tests on the reservoir. The GOR is the measured production GOR, and we show that the actual performance, you see that actual curve that -- well, it's labeled "actual", and what we show on this is several runs set up for a single porosity system set up to insure that we had a solution gas drive producing mechanism. In other words, we didn't allow gas to migrate, to segregate to the vertically upper reaches of the reservoir.

And the two things that we got out of that is that we -- when we compared what the similator told us, which are the values that are the curves that kind of go flat for awhile and then they go up very abruptly, we see that the breakover point for each of these similator runs, and we show three of them on here, the breakover point occurred compared to the actual field performance, certainly closer to a value of 1660, than it did either to the pressure that we've used initially of 1770 in the last hearing or the pressure from the Loddy pvt sample, which was 1498.

Now the second thing we concluded, also, is that the shape of a solution gas drive curve yields or indicates a much steeper increase in gas/oil ratio with pressure depletion than what we've actually observed.

And so as we'll see when we discuss our reservoir analysis section, we'll see that this is one of the reasons that we don't believe that we -- that we don't believe that we have a solution gas drive reservoir.

Q Okay. Now would you turn to Figure 43 and explain what Figure 43 through 47 indicate?

A We, this report, we intended it to be as complete as possible, so what this information is presents simply the fluid properties that we used in our subsequent evaluation, and what we've included in Figure 43 is a term we call oil formation volume factor, which is the relationship of a barrel of oil in the reservoir containing its dissolved gas, to what that barrel would occupy at the surface, and then that is a relationship that is related to the pressure in the reservoir itself, and so in general we see from this value that I imagine has bee quoted before, that when we're talking about the Gavilan Mancos Pool oil formation volume factors, initially in the range of 1.3 reservoir barrels yielding one stock tank barrel of oil at the surface.

Figure 44 is a figure that once again needs to be relabeled. The Y axis reads "oil formation volume factor". That Y axis actually represents the amount of gas dissolved in the oil; in other words, the dissolved gas/oil ratio expressed in terms of standard cubic feet per stock tank barrel.

Figure 45 is the relationship of gas formation volume factor to pressure.

Figure 46 is the relationship of oil viscosity to pressure.

From Figure 46 we do note that we're dealing with about a half centipoise viscosity oil. We're not dealing with particularly heavy oil in this Gavilan Mancos Pool.

These figures comprise the set of fluid properties that we used in our analysis.

Q One of the main components of describing a reservoir is the magnitude of the resource base from which you are producting. Would you describe how you calculated original oil in place?

Well, before we go to that, I don't think you -- you skipped Figure 47. Perhaps you'd better address that first.

A Okay. I just wondered if we might take abut a five minute break?

Q Sure.

A I'm starting to get hoarse.

(Thereupon a brief recess was taken.)

MR. LEMAY: Mr. Lopez, you may continue now.

Q I think I jumped ahead and skipped Figure

47. Would you explain what 47 is (not clearly understood) to show?

A Yes. Figure 47 is our first -- is the first figure that we have that relates to our calculation of oil in place, and I might -- might say before we get into that calculation, that we have done a material balance calculation of oil in place. We've heard previously that material balance, at least in terms of studies, are not necessarily going to be as sophisticated as a computer modeling study, and I think that is -- is correct, because the modeling study can take into account variable dimensions and variable properties, and we agree wholeheartedly on that.

On the other hand, we believe that the material balance approach is a valid approach for calculating oil in place and we have consequently utilized that approach.

The first figure that we have in the calculation of oil in place is Figure 47, which our history of well pressures plotted versus cumulative oil production, the total field oil production expressed in thousands of barrels. The scale, once again, the well pressures, are expressed on a scale from zero to 2000 psi and the cumulative production numbers, then, are expressed on a scale from zero on out to 4-million barrels.

Current cumulative production that we had recorded as of January 1st, 1987, was a value of about 3.15-million barrels and the very last pressure points that we have plotted for individual wells after that point at which our factual production ends, are simply estimated at this time, a continuation of the field producing rate at an estimated rate of about 3600 barrels per day.

The individual well pressures are plotted versus -- versus cumulative production, cumulative field production, and each individual well is designated as shown in the legend, so we have different symbols and different colors to represent different individual wells.

From this plot one of the things that we see is that the sharp trend in declining pressures that was observed in 1985 and '86 is not qutie so apparent because -- well, it's not quite so apparent on this type of plot because in 1985 and 1986 the reason the pressure decline was so severe was that the field producing rate was increasing.

The pressures that we have on here, we have attempted to draw some bounds on those pressures. We hae an upper bound shown that represents more or less an extrapolation of several pressures measured basically -- well, I think it's pretty obvious what the upper bound is.

The lower bound, representing the lower bound, is sort of a lower envelope including most of the pressures, and then the pressure that we used in our study was a value of about 1800 psi. That's the initial pressure used in the study.

And what we're going to see later on is that we believe that this pressure is a little below what the initial pressure in the Gavilan Field area would be naturally, indicating that we have had some minor influence of pressure the production that occurred previously in the West Puerto Chiquito area.

These pressure are measured with a datum of +370 feet subsea.

Once again, the two pressure points that are on the upper righthand side of the graph represent the pressures from the Davis Well measured in the C Zone and they may or may not reflect true C Zone pressures because they may be affected by supercharging associated with the well stimulation.

We have taken this pressure history and we've drawn what we consider to be sort of a best fit trend line. We've not done any kind of statistical analysis, nor have we done any kind of volumetric weighting of pressures in order to determine an average pressure, but rather we have taken something that we believe is a statistical best fit with a pressure versus production history. We do note that for many of the fields that there has been -- many of the wells, there is good pressure communication between those wells, such that there is not a large pressure difference between those wells so that we can draw a reasonable trend fit more or less through the center of the data.

Now, the next thing -- the next thing we did is we're about to -- we want to do a material balance calculation to determine oil in place. Before we do that we need to review the points in the -- in this calculation that we would consider to be valid versus the points that we wold not consider to be valid and we -- we recognize that when you have a reservoir that is -- that has a fair amount of structural relief from the very top of the structure to the very base of the structure. Then you could have a situation occur where the pressure in the reservoir may be such that a portion of the reservoir, the upper portion might be at a lower pressure, a pressure below the bubble point where you have free gas saturation in that upper part of the reservoir, and you also have a portion of the reservoir at the same time that is still at a pressure higher than the bubble point, and that is what we call an undersaturated reservoir, and during that period of performance where we have a -- well, I'm sorry, I may have misstated that.

During that time frame that is -- that occurs when there is a -- both a region in the reservoir that is above the bubble point and a region in the reservoir that is below the bubble point would have what's referred to as a partially undersaturated reservoir and a classifical material balance approach will not work during that time frame.

So in order to investigate what that period of time was, we constructed what we call a cumulative bulk volume versus depth distribution for the reservoir and this is what we show in Figure -- Figure 48.

What we have in Figure 48 is measured depth above sea level, starting at 150 feet above sea level going up to as high as about 650 feet above sea level, and we took the map of the Gavilan Mancos Pool and we determined the amount of volume that would contained at any -- at any particular depth level, so if we're at 650, well, at 650 there is really no volume above that, that depth.

As we move down to about 450 feet, then there is a number that turns out to be, it looks like about 1.5-million acre feet below that point.

And then as we go deeper and deeper into the reservoir, we basically accumulate all the volume that we associate with that reservoir.

Now this bulk reservoir volume versus depth relationship is set out for the A and B Zones because we believe that those are the productive zones; that's what our reservoir performance information indicated to us.

Q So the C Zone is not included in that.

A No, the C Zone is not included in this.

Now, when -- if we take our pressure versus time history and we recognize that that pressure versus time is -- is evaluated at +370 feet subsea, we can actually use that to determine the point in time that we will first have the bubble point pressure reach the top of this -- of this reservoir volume, and in doing that we determined that that would occur in approximately the middle of 1985.

We also determined the point in time in which the bubble point pressure would be reached at the bottom of the zone as being early 1986.

So prior of 1985, mid-1985, we do not believe that we had a significant (unclear) gas saturation in the reservoir associated with (not understood) working below the bubble point.

And then after the early part of 1986 we believe that the entire reservoir volume is at pressures below the bubble point pressure.

Okay, so what this has done for us is identified that period of time that we do not feel a material balance calculation would necessarily provide meaningful results and that period of time extends from about mid-85 to early 1986.

The next figure that we have is Figure 49, which is our calculation of oil in place and in order to calculate the oil in place in the Gavilan Mancos Pool we have to -- we have to know the pressure production history, which we've just shown you on one of the preceding -- preceding figures.

We also need to know the fluid properties, and we've just finished discussing the fluid properties that we believe occur in the reservoir, and with that information it is a reasonably -- well, it's a very easy calculation to determine oil in place.

Now, what we have done is we have taken the historical pressure-production information beginning in October 1st, 1983 and extending through January 1st, 1987, and we show that about the middle of the page, Historical Pressure-Production Information. We've tabulated out what our trend line indicates as average reservoir pressure. We've tabulated out what the cumulative oil withdrawals in the field have been at each point in time; also the amount of cumulative gas production at that point in time, and then we've recorded what the gas/oil ratio is at that -- those individual points in time.

We -- under the, about the fourth line down we have what we call Control Parameters. We know the value of PI, that's our initial pressure. We've said that the initial pressure, based on our trend is 1800 psi in Gavilan. Then two values over we had a value of Cf. That stands for formation or rock compressibility. That rock compressibility value is a value of 100 times 10 to the -6, consisten with our laboratory measurements and that is what that value is.

We then go through the material balance calculation of in place at each of the pressure-production points and we calculate out oil in place, and those are the values that we show at the bottom of the page, and we note that the values have -- obviously show some degree of variability and part of the reason they show a degree of variability is that you have to, if you're going to apply this approach, you have to be able to estimate average reservoir pressure and it is not always easy to estimate average reservoir pressure in an accurate fashion, partly because you don't always have individual pressures from individual wells, and so when we draw a trend line we recognize that we will have some deviation from the true average reservoir pressure by doing that, that type of procedure. So an individual analysis, an individual value for oil in place, we don't necessarily consider particularly meaningful. It is really if we can get several values of oil in place that tend to give us a single value that we think we can then tend to believe as the -- as the correct oil in place value.

So these are the values that we calculated versus time, the results of our oil in place calculation.

I should emphasize that we have done many, many more calculations than what we've shown here. We have attempted to -- we calculated oil in place values for various ranges of formation compressibility. We'd calculated it for different values of fluid properties. I think -- I think that's -- those are the two main variables but you are going to get substantially different -- different answers if you use different formation compressibility and if you use different fluid properties, and the values that we arrive at here on Figure 49, it's been an intricate type process where we have worked with an assumed set of parameters, found that data was inconsistent with field performance, come back, then, and revised our estimation of fluid properties until we finally arrived at a picture that is consistent in its interpretation of field performance and fluid properties, rock compressibility, permeability thickness, et cetera.

Figure 49, the results of oil in place calculations that are -- that are shown on that figure have been plotted in Figure 50.

Figure 50 is shown on the lefthand side of the graph. It's called Apparent Oil in Place expressed in millions of stock tank barrels. These are then the values that were calculated based on the pressure production history at various points in time, as shown by the x's, and we see that the early values trend upward to a line that then flattens out for a period, has a very sharp spike in the calculated oil in place value. Then it goes back down, levels off for a period, and goes back down again.

The period we've already noted in terms of where we had a partially undersaturated reservoir occurs from mid-1985 to early 1986 and we note the conventional material balance calculations are not valid during that time period. So we have excluded those, those points from our analysis and we see that the remaining points tend to have at least five of the points, five or six of the points tend to have an indicated oil in place value of around 55-milion stock tank barrels for the Gavilan Mancos Pool.

The value of 55-million barrels last -- at the August hearing, we -- we utilized a value of 100-million barrels at that point in time but we recognized at that point in time that our rock compressibility number might be in error and since that time we've taken steps to correct that formation compressibility number.

So we calculate out 55-million barrels in place. We -- and that's what we believe to be in the Gavilan Mancos Pool based on the pressure production history.

Now, one of the -- one of the questions that we had, one of the concerns that we had, and one of the things that we believe is at least partially supportive of a dual porosity system is indicated by the cross-hatched area. When we showed in the period late 1986 and early 1987, we showed the oil in place values continuing to decline, the calculated oil in place, down to value in the range of 40-million stock tank barrels.

Now, obviously one of two things -- well, one of, I guess, a couple things could be -- could be in error.

First, we may not have the true production recorded for the Gavilan Mancos Pool. We may have some production that is -- that is not being included in the total pool production.

The second possibility is that the -- that the average pressure is not correct, and that is the thing that we believe is happening.

If you recall back where we talked about a dual porosity system, we said that there had to be a larger pressure in the matrix than pressure in the fracture system in order to cause fluid to flow from the matrix into the fracture; otherwise there's no pressure differential and there's no reason that fluid would flow into that high capacity fracture system.

As a result of that the fracture system depletes at a different rate than the matrix system. That is not necessarily bad because it induces a larger pressure drop between the two -- two components of the dual porosity system and it causes the matrix feed-in to be more rapid, but it does have an effect when we do a pressure build-up survey, and that pressure build-up survey will initially start to measure the pressure in the fracture system and it will start to build, build-up, but before it can get built-up to a value that is indicative of average pressure in the vicinity of that well, we will start seeing interference effects from other wells that are also taking oil from that high capacity fracture system.

So we don't build-up to a true average pressure, and consequently the pressure we've used in our oil in place calculations will be a value that's too low and we will calculate then too low of an oil in place.

And our final figure with respect to reservoir description is Figure 51, and that is a plot of the fraction of oil in place produced versus the pressure as we see it relating to the matrix and as we see it relating to the fracture system

Now, one of the things that you're going to see tomorrow is that we believe in the Gavilan area on the average that as much as 90 percent of the oil storage volume is contained in the matrix with 10 percent contained in the high capacity fracture system.

The results of our analysis using a dual porosity system, then, is what we show here. This is generated by our computer model. It shows the pressure in the matrix and it shows the pressure in the fracture and it shows what the average pressure is, and you note that the average pressure is close to the matrix pressure because most of the volume resides in the matrix itself. So with higher rates of depletion that occurred in, well, particularly in 1986, you see that the increased pressure differential between the fracture pressure and the matrix pressure is such that when we then shut in a well connected with the high capacity fracture system, we're less likely to build up to the true average pressure prior ot seeing interference than we would see -- than we would -- than we would have had earlier.

So what we believe is that these last pressures that have been measured have not necessarily been completely representative of true average pressure in the reservoir, and so the values of 40-million barrels of oil in place that we calculated in the last few days for oil in place, we do not believe representative.

We believe that the oil in place is indeed on the order of 55-million stock tank barrels for the Gavilan Mancos Pool, or at least for whatever is pressure communicating in that particular area.

So in summary, this completes our reservoir description. We've attempted to describe all of the rock properties that we obtained. We've attempted to specify that we have -- to identify the flow system that we're dealing with, this being a dual porosity system, and the rock properties. We've attempted to identify the pore compressibility data, the fluid property data, the relative permeability data, and then combine all that into -- the pressure production data, combine all that into an interpretation of oil in place that yields 55-milion barrels, and in our reservoir analysis section we will show basically that -- that we can duplicate the field performance on that basis.

MR. LOPEZ: Mr. Chairman, I think this is as good a time as any to recess until tomorrow and I suggest that we do so.

MR. LEMAY: Okay, is that agreeable with you, Mr. Kellahin?

MR. KELLAHIN: No, sir, Mr. Chairman.

This hearing by ambush was cute earlier. It has now become very serious and we have a very grave due process problem I want to address with you on that.

MR. LEMAY: Okay.

MR. KELLAHIN: Mr. Greer's theories of this reservoir and our position in this case were made known to these parties in a 5-day hearing in August. Our position was the same then as it is now.

In an effort to accommodate the Commission and try to constrict this case to a one-week hearing, we had a meeting of all counsel in which the Chairman requested that by March 23rd, which was last Monday, the parties give you a position paper.

I gave you that position paper. In fact I had to reduce it on my photocopy machine so I could squeeze it on one page. We maintain that the opposition did not make a fair disclosure to us on their position.

In addition we find out today that Mr. Hueni's testimony in August, he's abandoned his hypothesis in August, his position then was that the explanation of the reservoir is that this was a reservoir that was operating under a secondary gas cap expansion. We now find that he has changed that hypothesis.

They have very carefully taken out portions of this exhibit book and they've displayed them to us not in a complete package but only in sections, and he has presented to us a very complicated hypothesis.

We presented the opposition with Mr. Greer's complete exhibit book on Monday, the complete Sun computer reservoir simulation on Monday. They had overnight to look at that book, and to cross examine Mr. Dillon.

In the spirit of fairness we request that the opposition give us the balance of the exhibit book for Mr. Hueni so that we have a fair opportunity to understand what his conclusions are, what his reservoir simulation is, and what his ultimte analysis of this reservoir is. Without having that to study so that we can fairly respond, we will not be able to conclude this hearing and we will be compelled to ask you for a continuance of this case following the completion of his presentation tomorrow.

In all fairness we would request that we be given that information so that this is not a hearing decided on ambush and gamesmanship, but that we make a serious effort to study and understand the reservoir mechanics and so that each set of opponents and proponents have some reasonable fairness in responding to the other's position.

We request that disclosure.

MR. LEMAY: Thank you, Mr. Kellahin. Now you want to address it, Mr. Lopez?

MR. LOPEZ: Yes, Mr. Chairman. There is no rule of the Commission that requires exhibits be introduced before the witness is prepared to testify the case to them, but this was a case, and Mr. Greer's exhibits were available and ready last week and we could have made demand and called for the exhibits at that time.

The only reason we were given Mr. Greer's -- or Sun's computer simulation model was because Mr. Greer during his testimoy on Monday had to lay a foundation for the parameters on which the simulation models are made.

There is good reason that the Commission has no rules that require the disclosure of exhibits until the witness is prepared to introduce them, because as in this case, we've been assembling exhibits even as we were having a recess at lunch today.

I see no requirement that we -- and I see no failure in the sense of fair play. We had no idea at the August hearing that Mr. Greer was going to expand the West Puerto Chiquito Mancos Pool to include the whole Gavilan Mancos Pool. He never made us -- made to us available the interference tests that he testified to on Monday. We had his exhibits for the first time Monday and after a fifteen minute recess crossed and completed our cross examination.

I absolutely see no reason that we have to comply with this request and I think there's no due process requirement there.

MR. LEMAY: Yes, sir, Mr. Carr.

MR. CARR: May it please the Commission, the question is whether or not we have an opportunity to review this information so that we can cross examine Mr. Hueni's testimony. It's a complicated formula and it's a complicated reservoir model that they're going to present tomorrow morning.

There was no opening statement in the case. We were today finally advised what direction they were going in certain respects, and we have a question here, I think, that -- it's a fundamental question is there a right we have, if we're going to be entitled to examine his testimony. If we don't, we won't be able to represent to you -- we'll have to tell you that we can't stay within a time frame that so far we've been successful staying within.

We really welcomed the opportunity to meet with you a few weeks ago to exchange statements outlining the position that we were going to take and I think we did that.

The two sentences that were provided on the other side, I don't think that's the spirit of those meetings. I think we have a situation here where there's a strategy to hide the ball, to keep everything under wraps so that we don't have an opportunity to review it before it's time to cross examine, and I submit to you that violates our fundamental rights to due process.

We think that no one here has said they don't have the information. No, they say, well there's nothing that requires me to give it. Well, I feel there is something that requires them to, and that's our right to due process and if we don't have it tonight, if we don't have an opportunity to review it, we will has to ask for a continuance as soon as we get it.

MR. LEMAY: Mr. Pearce.

MR. PEARCE: I'm the person that's charged with the responsibility of cross examining Mr. Greer. I believe Mr. Kellahin is wrong. The case that Mr. Greer presented on Manday and that we took a fifteen minute recess on and that I cross examined him on was not the case that he presented in August.

He did not ask for the expansion of the West Puerto Chiquito in that hearing. He did not present that interference data at that August hearing. I think that is a critical element in his case. Once he came forward with that and once he presented us with his exhibits, we did rise and cry, "We can't be ready".

You have before you, and perhaps I ought to exclude myself, but you have before you the most experienced set of oil and gas regulatory attorneys in the State of New Mexico. Each side in this proceeding has a battery of experts behind them.

We don't have a fairness question (inaudible), Mr. Chairman. What we have is an attempt to get ahead in our opponents policy. Clearly they want to have a longer time to prepared for cross examination; that's what this is all about. They want to have an opportunity that we did not have. We did not cry about that. We did not believe that was a violation of due process. These hearings run by finishing a witness, beginning cross examination. This agency does not have a history of making exhibits available before the hearing. When Mr. Hueni testifies about materials he will provide those materials, as Mr. Greer did.

I don't think we've got a due process question. We've got a question of somebody wanting to get ahead.

I don't think that's necessary. I don't think the parties are incapable. You may remember Mr. Dillon's testimony. He testified that Sun had lots of models. They chose the one they thought was appropriate.

We chose the model that we think is appropriate. These parties can be ready to cross examine and I think they should be required to go forward. In the discussions of this matter with the Chairman and the Commission before the hearing, we did not agree to exchange exhibits prior to hearing and it has not been done in this agency, and our opponents seek to have that done now. I don't think that's necessary to give them fair protection. I don't think it has -- it is what has been afforded to us in this proceeding. I think we have been expected to proceed. Mr. Greer finished, I was expected to get ready and go. I got ready the best I could and I went. That's not an unreasonable thing to request of our opponents in this matter.

MR. LEMAY: Thank you.

MR. KELLAHIN; May I close my argume-t very briefly?

Mr. Greer's theory was one, solution gas drive enhanced by gravity drainage. That was his theory seven months ago. They've had seven months to prepare on that theory.

Mr. Hueni's theory is known to us only today and Mr. Hueni has been prepared for the last two days to respond to testimony heard on Monday.

We're simply asking in fairness to understand what his position is, Mr. Chairman.

MR. LEMAY: How many additional exhibits do you plan to introduce, Mr. Lopez?

MR. LOPEZ: I think -- I think we have 100 figures total and we have gone through 51 of them.

MR. LEMAY: So you have 49 figures that are not in the book that you will provide tomorrow, or plan to provide tomorrow, and then have testimony on those 49 figures.

I want to take a five minute recess and confer with my colleagues and come back with a ruling.

(Thereupon a recess was taken.)

MR. LEMAY: We have a ruling, but first I'd like to quote Rule 1212.

"Rules of Evidence. Full opportunity shall be afforded all interested parties at a hearing to present evidence and to cross examine witnesses. In general, the rules of evidence applicable in a trial before a court without a jury shall be applicable; provided that such rules may be relaxed where by so doing the ends of justice will be better served. No order shall be made which is not supported by competent legal evidence."

What we've decided is that there is no rule that requires the exhibits to be presented to all parties prior to testimony. Had there been two witnesses instead of one for Mr. Hueni, you would have the exhibits presented today and you would not have what will be coming in tomorrow; however, initially we did request that the essence of testimony would be presented in a form which would be summary and that was not done by the Hinkle firm, that we could feel what was coming next. I think that's Mr. Kellahin's and Mr. Carr's main objection.

We were alluded to the fact that we have an oil in place calculation coming up tomorrow that will show 90 percent contributed by matrix, 10 percent by the fracture system.

At this time we would like to have in summary form some of your conclusions concerning what Mr. Huey (sic) will testify to tomorrow. No exhibits are necessary but we would in a spirit of fairness like to have your conclusions.

I might point out that there will be ample time to cross examine Mr. Huey (sic) Friday. That will give you Thursday night and you'll be able to re-direct testimony on Friday. We've reserved some time for that, so it's not like we're cutting you off tomorrow.

MR. LOPEZ: If you could give us a minute, Mr. Chairman, to figure out exactly what kind of conclusions you are requesting. I thought I made those fairly clear in my opening statement, what conclusions we reached.

I think that it is our position and the position that we took at the August 4th hearing that this is not a gravity drainage reservoir. That hasn't changed.

MR. LEMAY: Okay, that's important. It has not changed.

MR. LOPEZ: That has not changed.

MR. LEMAY: You agree it is partially gravity drainage.

MR. LOPEZ: It is not.

MR. LEMAY: It is not gravity drainage.

MR. LOPEZ: No.

MR. LEMAY: I think Mr. Huey (sic) referred to the fact it was not gas solution.

MR. LOPEZ: We also agreed that --

MR. LEMAY: We don't want to put words in the witness' mouth.

MR. LOPEZ: I'd also make the other observation, Mr. Chairman, that the proponents had every opportunity to participate in Mr. Hueni's study but refused to do so.

MR. LEMAY That point is taken

and noted.

MR. KELLAHIN: May we require them to tell us what model program was used to simulate the reservoir? We need to know that, Mr. Chairman.

MR. LEMAY: I think we're over -- we're not talking about the types of proof that Mr. Huey (sic) is going to go into. We're just -- we're just talking about his conclusions. The proof will be forthcoming tomorrow which can be studied and you'll be able to go after that on Friday.

MR. PEARCE: Mr. Chairman, I think it may -- may help our opponents more than I'd like to, but it may be of assistance to them, there is a Section 1 of the proposed notebook entitled "Summary and Recommendations", and if the Commission believes it would be of assistance, we will at this time make that available to everyone who's received copies of this exhibit, copies of the notebook, I mean.

MR. LEMAY: I think that would be helpful.

MR. PEARCE: May I have just a minute? I have copies right here and we will distribute them.

Mr. Chairman, for my own clarification, I have now passed out all of the copies of that

"Summary and Recommendations" section which I had. I'm not sure I got everybody. If other people need one and will see me immediately after the hearing, I'll get them one.

MR. LEMAY: Appreciate that.

MR. PEARCE: Yes, sir.

MR. LEMAY: We shall convene tomorrow at 8:15.

MR. KELLAHIN: Than you very much.

MR. CARR: Thank you.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record of this portion of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR