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

21 & 22 August 1986

COMMISSION HEARING

VOLUME III

IN THE MATTER OF:

Application of Jerome P. McHugh and Associates for an amendment to the special rules and regulations of the Gavilan-Mancos Oil Pool...	CASE 8946
and	
Application of Benson-Montin-Greer Drilling Corporation for the amendment to the special rules and regulations of the West Puerto Chiquito-Mancos Pool ...	CASE 8950

BEFORE: Richard L. Stamets, Chairman
Ed L. Kelley, Commissioner

TRANSCRIPT OF HEARING

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of the tool in the hole referenced from pad number 1.

Well, the Welex tool keeps track of -- in its computer, track of pad number 1 also but they have not gones one step farther. We have the mechanical unit but they have one curve and it's listed on this log here of the azimuth of pad 1, which is the same as in Schlumberger only they haven't -- they haven't shown it represented in a more polished form.

But what we see is --

Q Excuse me, are you referring to the central log (not audible clearly)?

A Yes, I'm sorry. Yes, the 4-arm dip fracture profile log run on the Marauder Well.

And on the lefthand side -- righthand side of the depth track we have curves and these are the same micro-resistivity readings that all four of the pads are picking up, and what the computer does, it compares pad 3 with pad 2 and pad 2 with pad 1, and then as we go to the far righthand side of the log we see pad 1 compared with pad 4, pad 4 compared with pad 3, and in effect we have the same thing, we have to visually look at it as opposed to the computer doing it for us.

Where we have separation of the pads we can determine which pads are seeing an anomaly, which pads are seeing the fracture. And if we determine that pad 1 is seeing the fracture and pad 3 is seeing the fracture, we go back to the lefthand side of the log where the asimuth of pad 1 is being shown and we know that what that asimuth is, pad 1 is at that azimuth and pad 3 is 180 degrees apart.

Although pads 2 and pads 4 are seeing this fracture, we still know the asimuth of pad 1, it's a simple calculation to add 90 degrees for the orientation of pad 2 and then 270 degrees from pad 1 to get the orientation of pad 4.

You can also, I mentioned yesterday and it was well illustrated on the Bearcat Well, the rotation of the tool as it goes up the hole and as you hit the fractured interval the tool stops and parallels the orientation of the fracture in the hole until it gets out of the fracture and then it continues rotating. You can still see the same representation on the Welex log only you have to look a little closer because the computer hasn't done this for you, but this -- if we look at the bottom of the log of the Marauder, the righthand, the solid line curve is the azimuth of pad 1.

As we can see that is changing over the casing into a fracture interval of about 40 feet. It maintains a constant asimuth following the fracture plane through that interval and then it starts rotating again and it gets to another fractured plane interval and goes along that same asimuth till it gets out of that and then we have a long (unclear) where it's also following a fracture and then it starts slowly rotating again as it gets out of the fracture again.

I mentioned yesterday that on Bearcat we saw the orientation of the tool rotating till we got to the fracture and I showed you real well on the Bearcat because the way Schlumberger represents their log, that we have a fracture trend and this fracture trend extends a great distance. I have the top of the B zone marked and the top of the A zone and a fracture log and we can see that the large fracture interval extends through most of the B zone on up the hole ot the top of the A zone, so you can see that there is some vertical communication with fractures throughout the Niobrara interval.

And you can see on the other righthand log of Bearcat, which is the dual induction log, and I also have the top of the A, B, and top of the C zones listed showing the gamma rays, the SP's, and the induction, showing the make-up of the formation, sandstones, siltstones, and shales, and we can note the -- they're not to scale but we can easily see that the fractures are actually extending throughout the interval of the Niobrara. So we can see vertical communication within the wellbore of the different zones.

Q I now refer you to what's been marked as

Exhibit Number Eight and ask you to discuss this.

A What are the orientation of fractures measured within the Gavilan-Mancos Field?

A Okay, I said that the new logs that we ran on the last three wells that we drilled were able to do this.

On the Schlumberger log it's rather easy to determine because the computer had showed us exactly the orientation of each of the pads. I would show you Exhibit Nubmer Eight here, the center plot is a polargraph plot of the Bearcat No. 1 and what I did was I looked at the pick up of the zones on the fracture log that I interpreted to be where we were seeing fractures, then identified which pads were seeing the fractures.

From that I was able to tell from their azimuth orientation which direction the fracture was trending.

On the Bearcat No. 1 took that large interval that I noted that penetrated both the -- most of the A zone and most of the B zone and since that one looked to be the dominant fracture trend in the wellbore, I gave that weighted -- a little bit more weighted average and said that's probably the major fracture for that particular area, and I notice that pads 1, pads 2 and pads 4, were seeing the fracture and I noticed that as you plot the asimuth of pad 2 and pad 4 on the polar graph, you can see that the fracture is trending north 20 degrees west, because pads -- pads 2 were showing us that -- pad 2 was oriented at north 20 degrees west and pad 4, being 180 degrees from that was at north 160 degrees, and therefore it's a double check. You know that it's already 180 degrees but if you plot both pads on the polar graph you should see them line up in a north 20 degrees west orientation.

Now, I also have two other orientations on my polar graph here and I identified other fractures within the wellbore and I interpret these to be minor fracture orientation trends since they didn't cover large amounts of the wellbore, and again I've plotted which pads were seeing the fractures and their orientation on the polar graph and I got minus blip at north 40 degrees west, the orientation that that was trending.

Then we see a line off to the side by itself not going through the center of the polar graph. This is an area where pads 1 and pads 2 saw the fracture. They were 90 degrees apart. Well, if you plot the orientation of pad 1 and then plot the orientation of pad 2 and you draw a line between them, you can see that it pretty well follows the same orientation as the major fracture trend. It's actually about north 2 degrees west.

So even though we didn't have pads 180

degrees apart from each other, as long as two pads in the wellbore see this fracture, we can still tell its orientation.

Okay, now on the Marauder No. 1, and that's the polar graph plot on the lefthand side of the exhibit, it's not as easy as the Schlumberger log and this is where you really need the polar plot, as you know that the azimuth of pad 1 and you pick which fractures -- which pads within the wellbore see the fractures.

And again I saw that most of the fractures were oriented and I plotted them on the graph and noticed that the major orientation was about north 6 degrees west; two minor orientations of north 40 degrees west, and one trending north 20 degrees west.

I did that for the third log that we had in our files on the Invader No. 1, which is in the northwest of Section 1, 24 North, 2 West, and again I felt I was able to determine that a large majority of the fracture trends were in the same direction so I gave more weight to that one and said that's probably the major orientation, the major fractures are oriented this way.

And following the same procedure that I did on the Marauder No. 1, I determined that the major fracture orientation was trending north 30 degrees west with the minor set at north 40 degrees west and a minor set at due north.

Q Does this indicate a laced fracturing system within the reservoir?

A Yes, I believe it does. I don't think that the tool can pick up every fracture in the wellbore but we do see major trends and we see minor other fractures in the wellbore, and sometimes you do see, when you pick up fractures on a pad sometimes you see on three pads and you know on two of the pads what that orientation would be and many times it's in the same major fracture orientation and you see another pad opposite picking another fracture. We don't know the orientation of that but it might be the orientation of one of the minor sets that we mapped further up or down the hole and therefore these fractures could intersect and interlace throughout the formation.

Q Do you see any relationship between your three fracture measurements on the Gavilan structure?

A Yes, and I have plotted those on the structure map which is Exhibit Number Three.

These are represented by the red diamond areas here and what I've done is I noted back on Exhibit Number Eight that I identified what I thought were the major fracture trends orientations and these are the ones that I colored in red and then the minor set that I had mapped on the polargraph is indicated with small -- small black lines in their proper orientation.

I would like to point out that the measurements are for magnetic north and adjusting for the deformation which is about 13 degrees west of north in the Lindrith area, we would have to shift all fracture orientations 13 degrees to the west and I've done that for the major fracture orientations. This is represented by the large black arrow.

Q Do you have any other fracture measurements in this area?

A Yes, I do. Benson-Montin-Greer ran, I believe, three logs in the area and I have -- I just got these about a week to week and a half ago, didn't have a chance to add them onto my exhibit. I did take a look at them and mapped what I thought was fractre orientation.

We see this well here, the well in the northwest of Section 30, 25 North, 1 West, see the major fracture orientation north 10 degrees west with a minor orientation north 60 degrees west.

Likewise, in the southwest of Section 31, 26 North, 1 West, I saw the major fracture orientation at north 20 degrees west with a minor fracture orientation trending north 60 degrees west.

And the third one that I was able to find was in the southwest of Section 36, 25 North, 1 West, and notice that it was trending -- I only identified one major orientation and that was trending north 4 degrees west.

I plotted these on the structure map to show something that I thought was rather interesting. We know in the San Juan Basin from much of the literature that the regional fracture orientation is northwest/southeast and we see that to a major extent or lesser extent in each of these wellbores.

The major orientation of wells in the Invader Well, northwest Section 1, 25 North, 2 -- 24 North, 2 West, is showing that basic northwest/southeast pattern, but as we go north in different portions of the structure of the Gavilan Dome, we notice that this major orientation is shifting more toward the north and I interpreted that, it's my judgment that the structure is actually mapping the regional fracture orientation to creating other fractures besides those and in some areas they seemed to override and be the dominant trend and then just regional northwest/southeast structural trend.

Q So you feel that the structure of the dome is affecting the orientation of the fractures. Does the structure also affect the amount and frequency of the fractures?

A Yes. I had mentioned yesterday and I pointed out on the structural cross section that owing to the depositional nature of the Gallup interval, which is consisting of sandstones, siltstones, and shales, in some areas the ratios of sand to silt to shale are different and where you have differing ratios of the three basic rock types, you have differing amounts of susceptibility and I don't -- don't know just what percentage of rocks it needs to take to be more easily fractured than others, but with these varying amounts of ratios and rocks, they would be -- one area would be more susceptible to fractures than others. Likewise, when you get on a domal structure you have forces operating in several different directions and over a large area some of these forces may not be as dominant in this area as they may be in the other side of the dome or other areas, and so what you essentially get are dead spots where there are not many fractures and then other areas where it's highly fractured.

And where you have, if you assume that the only porosity in the reservoir is matrix, in the areas where there are not many fractures, you don't have very much oil in relation to an area in which you have a lot of fractures and more pore space and therefore you have more oil and we can see this in the drilling where some wells are capable of producing above their allowables and you get on a 320-acre offset and these wells produce 100 barrels a day, some more, some less, because your gross difference is that you've got capacity and I think that has a direct relationship to the actual amount of oil that's underneath that particular 320-acre spacing unit.

Q Do you see vertical fractures in the structure intervals as well?

A Yes, as I alluded to a little earlier, and the Bearcat Well shows this very well, and I mentioned that the main fracture trend, as shown on the oriented micro-resistivity log for the Bearcat, showed that there is a major fracture trend that is occurring from about 6810 up to about 6730, and that this extended from in the top of the B zone, from about the middle of the B zone up to almost the top of the A zone and we also see minor fracturing down in the C zone, also.

I feel that you have vertical communication through the different zones because we see fractures going up and down between the zones.

Looking back on the induction log, you can see that these fracture intervals penetrate the gamme ray peaks that indicate sandstones and siltstones and where they indicate shale. And so you have fractures that continue throughout the interval.

Q Do you feel there is a difference in fracture orientations between the Gavilan and the monocline?

A Well, as I mentioned earlier, the

regional fracture orientation in the San Juan Basin is pretty well documented that it's northwest/southeast and I pointed out that in the Gavilan Dome area I felt that this structure was controlling the major fracture orientation.

The monocline, we do not get that much structural interference except in the hinges of the top and at the bottom of the monocline and that the basic monocline itself has acted as one continuous block and probably, I don't have measured orientation in the Gallup interval like we do over in the Gavilan-Mancos area, but for the drilling patterns we see that in the Canada Ojitos area the historical wells, there's a series of about five or six wells that are drilled in the northwest/southeast pattern and these five -- there's thirty wells that have been drilled, I believe, in the Canada Ojitos Unit, I believe there's thirty, and the five wells that are developed along the trend on basic 320-acre spacing, have produced over 50 percent of the oil in the Canada Ojitos Unit.

So I think that in the monocline that we do see this northwest/southeast pattern yet in the Gavilan Dome area we see the Dome controlling the structure, the structural configuration of these fractures.

Q So could you summarize the differences that you see geologically between the two areas?

A Yes. As I pointed out, throughout the

stratigraphic column in the Pictured Cliff, the Mesaverde, and the Dakota, and what -- that we have productive capabilities on the Gavilan Dome whereas on the monocline we do not, and they all seem to stop and get close to or right in the center of this trough, this structural trough between the Gavilan Dome and the monocline, and I feel that at least in the Gavilan Dome area, that the Mancos formation has matrix porosity and that it is oil filled.

I think that this trough, it's my judgment that we see -- since we see differences up and down the stratigraphic column both above, in, and below the Mancos interval, that there seems to be some kind of a permeability barrier here within the trough. I don't know if it's -- I think it could be one of two things. I don't really have evidence which one it would be. There is a possibility that there could be a series of north/south trending faults in this area that are effectively creating a permeability barrier and that you do get matrix development within the different stratigraphic intervals on the Gavilan Dome whereas you don't get it on the monocline.

Or that within a synclinal trough as this you get compressible forces and the compression -- compression between the two areas is an effective permeability barrier.

Q So there may be fracturing within the

trough but that would be compressed.

A Oh, I'm sure that there are fractures within the trough. Just because there's fractures doesn't mean that they're productive. Fractures can be healed and what that is is mineral deposition can occur and effectively seal off the fractures. Where you do not have any permeability or even porosity, then the fractures are more -- you can have the original fractures of the regional trend within there and due to fluid movement you can get deposition within -- in the fractures and this could be an effective seal across lit.

Likewise, without mineral deposition in the fractures, compression can keep those fractures closed. They're still there but they're compressed together and in effectively there is no porosity and permeability of the fractures in that respect, too.

Q Were Exhibits Three through Eight prepared by you or under your supervision?

A Yes, they were.

MR. LOPEZ: I would offer Mesa Grande Exhibits Three through Eight.

MR. STAMETS: Without objection these exhibits will be admitted.

Q Does that conclude your testimony?

A Yes, it does.

MR. STAMETS: Are there questions of Mr. Emmendorfer?

QUESTIONS BY MR. LYON:

Q Mr. Emmendorfer, you testified yesterday about examining the samples and I don't recall exactly what you said about the amount of oil indications in the samples.

A Okay. On the mud log shows and the mud logger looked at the samples, and on most every mud log that I've seen they do report sands coming out of the Gallup interval and those correlate with the drilling breaks that you plot the drilling time on and many of these sands do have flourescence and cut if you were to look at them under the black light.

Q Do the records show or are you aware of any lost circulation problems at the intervals where those samples were taken?

A Right at that interval?

Q Yes.

A That is sometimes hard to do. Because of lost circulation the area that you're drilling, those cuttings many times go in the direction of the lost circulation down into the fractures and a lot of times you do not get those particular -- the cutting from right at that interval did not come to the surface.

Q So are you saying then that where you have lost circulation you don't get the samples and consequently those are not the samples that you got the cut or stains.

A Well, it __ I guess I am saying that; however, if I might say something. The fracture is what give you the lost circulation problem and not the sandstone.

We look at core data and we see, if you can recover core, you see fractures within that cored interval through the sand, siltstones, and shale, yet we still didn't lose circulation and with the improvement of the drilling, with all the drilling that's gone on in the area the mudloggers, the mud engineers have gotten quite a bit smarter and they've figured out mud programs to avoid lost circulation to a great extent, so instead of losing circulation, they will correct this problem and we are getting samples coming out of the wellbore at frequent intervals.

Q Now are the sand samples the only ones that showed the cut and/or stain?

A Sandstones and siltstones you have to have porosity and permeability, really, to get cut out of the samples, so you would not get the shales to do that.

Q So is it -- is it your conclusion that you are getting some oil recovery from the matrix where you have the sand or siltstone present?

A Yes, I would think so. If we could get cut s from these -- from these samples, if they're close enough to fractures we seem to have good indication that there's a large number of fractures out there that we should be able to get some matrix contribution to the production in the wells.

Q Okay, now referring to your Exhibit Number Seven, what kind of an indication on the dipmeter do you get that a fracture is being detected?

A Okay. Like I pointed out earlier, the tool reads, on each of the four pads reads micro-resistivity and whenever there's an anomaly of the micro-resistivity on any one or more of the pads, it will -- it shows a different resistivity and when you prepare those you can see there are differences from the normal resistivity and therefore those pads are seeing an anomaly and based on service companies testimony that where they've cored and run downhole televiewer type logs and these new fracture orientation logs they see a good correlation that these anomalies are indeed reading fractures.

Q Does the -- does the pad read an anomaly if you've got a lithologic change?

A All four of the pads should read the same thing. A lithological change would be represented all around the wellbore and so it's just a matter of the resistivity changing on each of the pads, but from, like from a foot below, say, where the lithological -- lithology is different.

Q Well, but can't you have small lithologic changes, nodules, where there are some variations to the sediments?

A I'm sure you can.

Q Would that show up as an anomaly?

A Yes, that's possible. We -- we don't rely on the orientation log as the only indicator of fractures. We use every tool that we have and the caliper log helps show that, whenever there is a blip on the caliper log (not clearly understood) assume that we're drilling down a fractured interval and we have an elliptical hole and therefore we're seeing affect on the fracture.

Q I see. Now in regard to Exhibit Eight, where you've plotted the fractures and their orientation on the azimuth charts, are these fractures concurrent at a given point or is this a composite of fractures which are detected in a larger interval?

A Both.

Q Can you -- can you tell me at what depth the various fractures were encountered?

A On the Bearcat I can tell you very easily and I believe I pointed that out, that that major fracture orientation to the north 23 west extended about 6810 up to around 6730.

On the other ones I can't tell you here. I could tell you if I had my logs in front of me but they're back in Tulsa.

MR. LOPEZ: We'd be glad to supply that.

A Yes, that would be no problem.

Q Well, I'm not looking really that much at specifics. I'm trying to expand my understanding of what he's representing.

But you're not saying that -- that all of the fractures indicated on each asimuth chart are there concurrently.

A No, the -- the -- you can't say that normally because of the fact that two pads will be reading one fracture.

You do have -- you do see evidence sometimes where it looks like three pads are seeing something and if a third pad, which is 90 degrees from the other two pads in both directions, are seeing something, there's possibly another fracture and that would have different orientating but they would be at the same interval and if they're both at the same interval they should intersect each other.

Q Right. If you have the information readily available I would like to have the depths that these fractures occur.

MR. LOPEZ: Are there logs in Tulsa?

A Yes, they are.

MR. LOPEZ: So it's not that readily --

A I don't need them now, just at your convenience.

MR. LOPEZ: Okay.

MR. LYON: I think that's all I have. Thank you.

MR. STAMETS: Other questions of this witness?

MR. KELLEY: I have one on this fracture orientation.

CROSS EXAMINATION

BY MR. KELLEY:

Q In reading your log, were there any fractures perpendicular to the orientation of this at all that you could pick up on your log reading?

A Orientation of the one --

Q Of the smaller fractures type.

A Well, those were the ones that I showed in a -- that were not extending across the graph. I depicted those as a minor orientations.

Q So you found absolutely none that were oriented northest to southwest.

A None that I was sure of. But sometimes you have one pad picking something up and if we could go back to Exhibit Number Six, we showed that -- that one fracture, a fracture can be penetrating the wellbore and be picked up by just one pad, and if, Mr. Stamets, if the log -- fracture that's shown on the very righthand side of that wellbore that intersecting pad number 2, and if you have an orientation, you pick up the orientation of one pad seeing a fractured, you could plot that thing out as being over on -- showing north 93 west, a due west; however, we don't know whether -- well, obviously pad 4 didn't show that so it would not be an east/west pattern. We would have the same -- we could have the same possibility that -- had the wellbore intersected that fracture a little bit farther and pad 1 would have seen that, also, as pad 2, then we would have that indication that when you plot those two orientations out, as we have on the Bearcat, that's it's off the center of the polar graph.

MR. KELLEY: No other questions.

MR. STAMETS: Are there any

other questions?

MR. LYON: Let me ask one more question.

QUESTIONS BY MR. LYON:

Q The orientation that you've mentioned there in the trough, were those magnetic readings or did you correct those?

A Those are magnetic readings. We had to orient those 13 degrees west.

Q All right. Okay.

MR. STAMETS: Mr. Kellahin.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Emmendorfer, you identified for us three logs that you had obtained from Benson-Montin-Greer wells in the Canada Ojitos Unit?

A Yes, sir.

Q And you stood before Exhibit Number Three and identified, I believe, the general location of each of those wells.

I ask you, sir, to take my yellow marker, and so I can see it identify for me those three wells in which you have examined and determined there was some fracturing and that you could identify the orientation of those.

A Circle the well?

Q Yes, sir, if you please.

You've identified a well in Section 30 in the northwest quarter of 30. I've forgotten the township and range.

A I believe that's a --

Q Which one was that?

A That's Township 25 North, 1 West, northwest of 30.

Q All right, and then there was a well in 31?

A Yes, the southeast -- southwest of Section 31, 26 North, 1 West.

Q And then in 36?

A Yes, the southeast of Section 36 in 25 North, 1 West.

Q I believe, sir, that's Section 6.

A Yes.

Q All right, sir. You've also identified on the exhibit in a general way the monocline feature that is seen in the Canada Ojitos Unit. Would you take a marker and approximate for me where we see that monocline?

A The monocline?

Q Yes, sir, I'm not a geologist; show me where it is.

A Well, before I color up the whole map can I start out with --

Q Well, point it out and then let's see what you're going to do.

A The monocline extends actually off this map but I believe Mr. Greer had a map with the East Puerto Chiquito Unit on there and that's the monocline and it goes up through the outcrop of the Niobrara and continues on and it continues all the way what I consider about in the center of this trough, which is a line between my Section 7 and Section 8, 25 North, 1 West, and it runs in a north/south direction, and actually this whole interval is the monocline

MR. LOPEZ: And that interval that you described, Alan, is between the east side of the map and the center of the trough.

A Yes, it's from the east side of the map to the western tier of sections running in Range 1 West interval.

Q All right, sir. Well, let's not mark on the exhibit.

If you'll take that line which you, in your opinion, have concluded is the western boundary of the monocline can you give me what the approximate structural depth is at that point as you've contoured?

A Well, it's at about -- well, it varies. We see the +400 sea level, +400 level here at -- about at the Township 25/26 border and then the majority of it seems to be slightly below a datum of +450, and then it continues up and you can see where it intersects the -- where the contours bend around as you go farther south.

So it is not at one structural depth. It varies from north to south.

Q All right, let's start with the well in Section 30, the lowest of the three yellow dots there.

A Uh-huh.

Q And what is the structural contour that you've identified at that point, what's the depth?

A +450.

Q All right and let's go due east from that point and have you read for me the next structural depth approximately a mile away.

A +481.

Q So in that mile we have gained 31 structural feet.

A It would appear that way. We've lost some first and then gained it back. We went into a trough and then back up the other side.

Q All right, sir, and moving off that 481 line and continuing east again, what is the next structual contour line?

A +500.

Q All right, sir. How far away is the well in Section 30 from the last point that you referred to?

A A mile and a half; about a mile and a half.

Q All right, sir, and how far away then is the next contour line as we move east?

A From the well in Section 30?

Q Yes, sir.

A A little over two miles.

Q And what is the contour point at that interval.

A +550.

Q So as we move east a little more than two miles the structure changes from about 450 to 550?

A Yes, sir.

Q All right, sir. If you'll look at the center of the three red shaded areas identifying the orientation as you've depicted it in those wells, pick the center one, if you will, please, sir.

A The Bearcat No. 1?

Q Yes, sir. Now if you move due west from that one what's the next well?

A Janet No. 2, it's a McHugh Well.

Q Bear -- is it the Bearcat Well?

A Yes.

Q What is the structural contour depth of that well?

A +529.

Q And as you move west to the McHugh well, what is the structural depth at that point?

A +414.

Q And how far away are those two wells?

A Close to a mile.

Q And what is the change in structural depth between the two wells?

A Oh, a little over 100 feet.

Q Mr. Emmendorfer, have you participated in the working interest owners meetings concerning the Gavilan-Mancos Pool?

A Yes, I have.

Q The last meetings that I believe you testified to yesterday were held in July of this year in Farmington, were they?

A The last meetings?

Q Yes, sir.

A The last meeting was held July 31st and Augsut 1st, the engineering committee.

Q That was the engineering?

A Yes.

Q Did you attend that, sir?

A Yes, I did.

Q And prior to that did you attend meetings of the working interest owners in the Gavilan-Mancos?

A Yes, in Farmington we had an engineering subcommittee meeting held on July 7th, 8th, and 9th and a geological meeting held on July 8th and it was held in conjunction with the engineering on July 7th.

Q And you attended all those meetings?

A Yes, I did.

Q And during the course of those meetings have you expressed to the other working interest owners the data that you have presented here today?

A What data are you talking about, all of it?

Q Well, you reached certain conclusions and opinions based upon some displays you have today. I don't mean the actual displays, the information that you've utilized to make those displays today, is that information that was commonly known among those working interest owners?

A Well, like I say, not all of it, because the scope of our study was the Gavilan-Mancos and so we talked mainly about the Gavilan-Mancos. I've got other stuff with me today to show the differences I feel geologically between the two structural areas.

Q Did you express to those working interest owners the similar comments and opinions to them as you've expressed to the Commission today?

A I had a rough map that I hung up on the wall showing the three fracture orientations on our wells. I did not have the Benson-Montin-Greer wells. I initially did not know the -- the significance of them until about two weeks ago, so I didn't show that.

I showed my interpretation of fracture orientation.

Q The interpretation that you've given to the Commission today, have you expressed those opinions and interpretations to the other working interest owners at those previous meetings?

A Which interpretations are we talking about?

Q All the ones that you've made today.

A Not all of them because they weren't at the meeting and like I said, we were only studying the Gavilan-Mancos.

Q And which ones of the opinions and comments that you've expressed today you have not previously raised with the working interest owners at any of these prior meetings?

MR. LOPEZ: Mr. Chairman, I object to this line of questioning. I don't see any relevance on the testimony here today. All the working interest owners that are interested in this case are here. We're talking about facts and circumstances as we see them today and what happened in the last month, I fail to see how it carries any relevancy to this hearing.

MR. KELLAHIN: Mr. Chairman, I want to test the depth and breadth of this witness' knowledge, what he has shared and what in fact may be new information that he's supplying to the Commission that we have not seen before, and I'm about through with that question. That was my last question and I'm waiting for the answer.

A Well, actually there's some interpretations --

MR. LOPEZ: Well, the Commission hasn't ruled.

MR. STAMETS: If the witness feels capable of answering the question we'll let him answer it.

A Something that I didn't point out although I alluded to, we saw stratigraphic differences and we can readily see that on the structural cross section. In the geological subcommittee meeting we held on July 8th, when we were picking the top of the Niobrara A zone, in some areas we had quite a -- quite a difficult time; we had quite a bit of discussion and the reason was that it's not all that easily determined. What we kept finding was that in some wells there was a little sand that appeared just above the Niobrara A zone and just looking at each particular log by itself, one day at a time, you'd say there's the top of the A zone, but when you looked at all of them together and we correlated, we'd bring the logs back until we were sick of looking at them, we determined that there's a extra sand in some of these wells that are not in other wells.

MR. KELLAHIN: I have nothing further, thank you.

MR. STAMETS: Other questions of this witness?

A Should I sit down or stand up?

MR. CARR: You may sit down.

CROSS EXAMINATION

BY MR. CARR:

Q Mr. Emmendorfer, if I understood your testimony you stated that the better wells in the area were those wells which seemed to intersect a fracture system, is that correct?

A Yes.

Q And so what we've been talking here, the thrust of your testimony, at least this morning, has been discussing the fracture system.

A Uh-huh.

Q Is it fair for me to characterize your testimony as saying what we're really talking about here is a fractured reservoir as opposed to a sandstone matrix type reservoir?

A A strict sandstone reservoir with no fractures?

Q Well, the primary characteristic of this reservoir would be that it is highly fractured, is that not true?

A Yes, it is.

Q I believe you talked about pore space in the fractures, did you not?

A I believe I did.

Q How does the pore space in the fractures, in your opinion, compare with the pore space in the matrix? Do you have an opinion on that?

A I think they're in communication with each other.

Q Do you have any estimate as to what percent of the recovery might come from the fractrures as opposed to the matrix?

A No, I don't. I don't think there's

enough study yet to actually determine the amount of matrix contribution that will be realized through the life of the field and I also think that it is more of a reservior engineering question than strictly geology.

Q And based on your information you do not know how much contribution might come from the matrix.

A I don't know a specific number, no.

Q You don't know in fact that there will be any.

A I think that there will be some.

Q Do you know that without the studies that you just talked about?

A 7000 feet below the surface, it's hard to look down there.

Q And so the answer is you really don't know then.

A I am optimistic that we will get some matrix production. We've seen matrix porosity and permeability and these -- this matrix, when we see the cuttings, did give up cuts, and I think that we will realize matrix porosity and production.

Q But it's very small compared to what you encountered in the fracture system.

A I don't know what that ratio is.

Q And so you really don't know what you're going to get from the matrix, do you?

A No.

Q Now you talked about a barrier in the western part of the Canada Ojitos Unit. You stated there might be faults. You don't know the faults are there, do you?

A No.

Q There's only a possibility.

A Yes.

Q You talked about compression in that area. You don't know if that results in an effective barrier that would permit migration of fluid, do you?

A No.

Q And you don't know if the fractures may have healed or not, do you, if they're even there.

A No.

MR. CARR: I have no further questions.

MR. STAMETS: Any other questions of the witness?

CROSS EXAMNATION

BY MR. STAMETS:

Q Mr. Emmendorfer, in your testimony did you say anything about the potential for gravity drainage in this reservoir?

A I don't believe I did.

Q Okay. Looking at your Exhibit Number Six, I'm unclear as to -- well, let me just -- let me just label these fracs that you've got in here. I'm going to label this Number 1, this major one that runs, what, north-east to the southwest?

A Yes.

Q All right, now that crosses pad 1 and pad 3. How do we know, how were you able to tell that indeed it's going northeast/southwest instead of crossing those two pads in a northwest/southeast?

A Well, that -- that is just a hypoptheti-cal case. It's just -- just shows the possibilities of how a fracture could intercept these two pads or any of the pads in the wellbore, and as I explained earlier, the tool ro-tates in the hole and the computer keeps track of where pad 1 is at all times. They know whether pad 1 is at -- facing to the east or to the north or any compass direction in be-tween and so when pad 1 and pad 3 intersect a fracture what-ever orientation that fracture is, and again I'd like to stress that that's just -- just a hypothetical case, because I could show you many orientations and for simplicity I just showed pad 1, pad 2, pad 3, and pad 4, to the major compass directions but in fact they rotate.

So any time that pad, any of those pads measures the fracture, we can back out and find out exactly what orientation that fracture is.

Q Well, is the active portion of that pad so narrow that there is no doubt as to what the orientation is when a frac is encountered?

A The actual width of the pad that actually does the reading?

Q Right.

A I don't believe it's the same width as the pad, unfortunately.

We have a problem when you take a tool and cut it into quarters and expand it out to a bigger -- bigger hole, you're never going to effectively cover the whole interval so luckily the tool does rotate in the hole and so we have a good chance of these fractures not escaping detection. One or more of the pads will pick these up.

Q Is it theoretical possible for a -- for pad 1 to detect a fracture which would go off between pads 3 and 4.

A Yes.

Q And for pad 3 to detect a fracture which would not be recorded on any of the others and receive a false indication that you've got a frac along the lines of pads 1 and 3 when in fact you don't?

A That's possible but it's my understanding that the fractures really don't curve and that they run pretty much in a straight line and when you're talking about a 6-3/4 inch hole, whatever size hole you're drilling, the fracture doesn't have very far to go to and maintain a straight line distance, and so I would think that -- that you would -- if you see it in pad 3 and it's oriented -- it's running across to the other side of the wellbore, you would see it in pad 1.

You do have the case where pad 2 would pick up the fracture but that's whenever the fracture intersects the wellbore at a tangent. That's the well I just defined.

Q I should have asked Mr. Greer this question but perhaps you know the answer.

Have any wells been -- any dry holes been drilled in the -- in the trough between the Gavilan and the main part of the West Puerto Chiquito?

A Right in the very center of the trough I don't believe that it's in the exact bottom of the trough, no.

Q Do we have a dry hole in there which would indicate that indeed there is some sort of a barrier, effective barrier between the two pools?

A No, we don't, but there could still be some matrix porosity there that would give up some oil.

MR. STAMETS: Any other questions?

MR. LYON: Let me ask a question.

QUESTIONS BY MR. LYON:

Q Mr. Emmendorfer, referring you still to Exhibit Six.

If you have an indicated fracture that extends from the right side of pad 1 over to the left side of pad 3, if you had a fracture that was from the left side of pad 1 to the right side of pad 3, would it show the same? The same indication of anomalies?

A Yes. It should show that we have a fracture.

Q Can you really tell the difference in a fracture whether it intersects as it's depicted here or is picked up on the opposite side, opposite sides of the pads?

A No, we don't. We do -- we do know that we're close and in the ballpark, but with this particular tool we don't. There's a new generation of tools that have multiplicity of buttons on the pads that read those and I would hope that in the future they'll be able to distinguish exactly which button on the pad is seeing it, and we could get more accurate as --

Q Well, in reality if you'd picked up a fracture this way, would you not have oriented that pad through the centers of the pads, oriented the fracture through the center of the pads?

A Yes. Luckily, since it's -- or we wouldn't even be drilling here -- there's lots of fractures in the reservoir and when you start picking up a lot of them, you start seeing the trends and you plot all of them on there, you can come up with an average trend and that's the important part.

Q Right, I understand. Thank you.

MR. STAMET: Mr. Lopez.

REDIRECT EXAMINATION

BY MR. LOPEZ:

Q Alan, I think we haven't directly confronted the questions that I hear being asked and what I'd like you to address is the confidence that you can put into these fracture readings, and I'm getting a sense that these pads are huge or -- and are unreliable, and so I'd like you to address why the computer can read with precision the degree reading on the fractures and also whether the consistency that you get in these different readings in the different wells gives you any confidence as well.

A Okay, well, the tool reads a little ways into the formation so it's going to pick up the fracture right at the wellbore and just a little ways into the well- bore and it -- the computer keeps track of all this and it's -- it's filtered out the extraneous data and actually gives you good readings.

Q Well, is the tolerance of the tool plus or minus three degrees?

A You know exactly what orientation the pad is. Well, it is however as good at compass reading, depending on the type of compass that they use what that plus or minus would be.

Like I said, when you have a major fracture trend, you're going to have more than one fracture and you're going to be able to see all those and you're going to be able to establish that this indeed is a fracture trend and orientation to the wellbore.

MR. STAMET: Mr. Lopez, let me kind of follow up on that.

VOIR DIRE EXAMINATION

BY MR. STAMETS:

Q I've got Exhibit Number Six here and I've drawn a green line on there which is probably 20 degrees different orientation than what we talked about as number one, how do -- how does the log know, how do you know it's going off this direction instead of off that direction?

A Well, at any particular instant and the tool is logging up the hole I believe at about 15 feet a minute, so at any particular instant you do not -- you don't know, we're talking like an inch or less, you don't know that a fracture can be oriented in the direction of your green line or number one line here, but as you're logging, the tool is still rotating a little bit in reading it, so it averages these things out and therefore you can get an orientation.

You can see on the Bearcat that even though -- when the tool -- when the tool is maintaining roughly the same orientation, you can still see that there are minor variations in there as the tool is going back and forth up the hole.

Q So you're looking at something that is two inches wide or four inches wide, in an instantaneous situation you couldn't tell what the orientation was but as that moves up the hole and rotates it gives you an idea by crossing the entire face of the tool what the orientation is.

A Yes.

REDIRECT EXAMINATION CONTINUED

BY MR. LOPEZ:

Q I think the other part of my question was whether the readings that you get from the different wells provide any consistency or reading the (not clearly understood).

A Yes, I think so. I noted that we have major orientations and we're picking them up and they are different, but a lot of minor orientations are the same, that we -- I feel that we do get great confidence that these are indeed the fracture orientations within the wellbore.

Q And my final question would be you were talking about the difficulty of getting any -- that data on the area in the trough.

Isn't it true that there have been some wells drilled in the trough area by Mr. Greer and all, that either are poor wells or dry holes?

A Well, the closest one to the center of the trough is the Canada Ojitos Unit No. 32 and that's in the southeast of 6 and from the indications that Mr. Greer told us in the subcommittee meeting, he thought that that was a fairly tight well and that there was -- that there may be -- he felt that there may be some kind of a barrier down there, and I see no reason that he could be wrong, and I do think there is a barrier in that trough.

MR. STAMETS: Any other questions of this witness?

If not, he may be excused.

A Thank you.

(Thereupon a recess was taken.)

MR. LOPEZ: We will now call Mr. Greg Hueni.

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 My name is Greg Hueni. I reside at 11420 West 27th Place in Lakewood, Colorado.

MR. STAMETS: What was the last name?

A Hueni. It's spelled -- I'll give you a business card.

MR. STAMETS: Thank you.

Q By whom are you employed and in what capacity?

A I'm Vice President in charge of reservoir engineering for Jerry R. Bergeson & Associates, Incorporated, of Golden, Colorado.

Q And what is Jerry R. Bergeson & Associates?

A Jerry R. Bergeson & Associates is a reservoir engineering, general petroleum engineering consulting firm, operating both here in the United States, as well as worldwide.

Q Were you employed by Mallon and Mesa Grande for the purposes of consulting on their operations in the Gavilan Dome area?

A Yes, I have been.

Q Would you briefly, or not briefly, but completely describe your educational background and your work experience?

A I graduated in 1971 from Rice University with a Master's degree in mechanical engineering.

Subsequent to that I went to work for Exxon Company USA in their Midland, Texas, office.

I worked from 1971 through 1975 in the reservoir engineering operations, studying a variety of different reservoirs with respect to reservoir -- in all phases of reservoir engineering in several different types of reservoirs, including fractured reservoirs, such as the Spraberry Trend Area and Fractured Ellenburger in West Texas.

In 1975 I moved to corporate planning function in Houston at which time I was involved in -- at least in part in teaching reservoir engineering courses to in-house reservoir engineers, as well as economics courses to the same.

In 1976 I was transferred to the Kingsville District, where I was the Senior Supervising Reservoir Engineer in charge of two groups of engineers, totalling 16 engineers.

In 1977 I left Exxon and went to work for Bergeson and Associates. Since that time I've been primarily involved in reserve and economic evaluations, reservoir studies, using both the classical approach to reservoir engineering, as well as computer simulation models; and I have taught reservoir engineering and well testing courses on an open industry basis as well as in-house.

Among the various engineering studies I've been involved with are several fractured reservoirs, including the Trap Springs Field in Nye County, Nevada; TR Field in the Williston Basin; Codell/Niobrara in the DJ Basin; the Buck Peak, a fractured Niobrara in western Colorado; the Madden Deep in the Wind River Basin, Wyoming; Austin Chaulk in South Central Texas; and overseas, the West Sole and Magnus Fields in the North Sea and the Dethlingen Field in Western Germany.

I've been involved in writing our manual for teaching of the reservoir engineering courses. I have taught them for the last five years on an open industry and in-house basis to companies such as British Petroleum. We teach both their worldwide reservoir engineering group as well as their research group in Great Britain.

I've also co-authored articles on multiphase flow and and analyzing performance on massively hydraulic fractured wells in West Germany.

I might -- I might add with respect to our reservoir engineering courses that two sections of our courses deal, one deals with solution gas drive reservoirs; the second deals with gas cap expansion reservoirs.

Q Are you familiar with the applications that have been consolidated in these cases before the Commission today?

A Yes, I am.

Q I tender Mr. Hueni as an expert petroleum engineer.

MR. STAMETS: Mr. Carr?

MR. CARR: Just a couple questions.

VOIR DIRE EXAMINATION

BY MR. CARR:

Q Mr. Hueni, is this your first experience with the Mancos Pool in this particular area?

A Yes, it is.

Q When were you first approached about looking into this pool?

A We were asked approximately four weeks ago by Mallon-Mesa Grande, who was concerned about the proper method of operations of the pool. They inquired as to whether we would perform a reservoir engineering study on their behalf.

We've done that. I was familiar with the pool prior to that inasmuch as Kodiak Petroleum is one of the interest owners in the pool and we have worked previously with Kodiak Petroleum.

Q In your work for Kodiak had you studied the pool at that time?

A We had reviewed the basic operation of the pool, yes.

Q What were you asked to do when you were retained by Mallon and Mesa Grande?

A We were asked -- we were asked the question whether the rates should be restricted and what level they should be restricted in order to promote proper operation of the pool.

Q And you advised them that you could make that study in a four-week period of time?

A We advised them that we could perform a reasonable engineering assessment within four weeks, certainly, and I think we have.

Q Were there any particular areas you were asked to focus your study on?

A We were asked to focus our study on the relationship between producing rate and recovery from the pool.

Q Were you asked to do anything other than just give your general opinion on that?

A Well, we were asked to do an engineering evaluation.

Q And you were asked to give just your opinion, you weren't given any indication as to --

A No, we were not given any indication.

MR. CARR: That's all I have.

MR. KELLAHIN: Mr. Chairman.

MR. STAMETS: Mr. Kellahin.

VOIR DIRE EXAMINATION

BY MR. KELLAHIN:

Q Mr. Hueni, have you previously testified before the Oil Conservation Division of New Mexico --

A No, I haven't.

Q -- in any of the San Juan Basin pools?

A I have not testified before the New Mexico Commission.

I've testified before the commissions in Texas, North Dakota, Wyoming. I've testified in Federal court, state court in the State of Colorado, and I'm also a registered professional engineer in both the State of Colorado as well as the Province of Alberta, Canada.

Q In making your preparation for today, did you review any transcripts, exhibits, and testimony in any of the prior Gavilan Mancos cases?

A I don't believe that I have reviewed testimony with respect to the Gavilan Mancos cases.

I have looked at some of the engineering exhibits previously prepared for hearings on the Canada Ojitos Unit.

Q Would you describe for us which of those engineering studies you reviewed on the Canada Ojitos Unit?

A I reviewed, I believe, some of the documents from Case Number 7075.

I have also been granted access through Mallon-Mesa Grande to the information put forth by the Engineering Sub-Committee or gathered by the Engineering Sub-Committee.

Q Which was Case -- you said 7075?

A Yes, I --

Q What is the name that goes with that case number, do you know?

MR. LOPEZ: I don't even know but I think it's something we could find out.

Q But that's the case you reviewed?

A Well, I don't want -- we looked at the engineering data contained in that case.

MR. KELLAHIN: I have nothing further.

MR. STAMETS: Any other questions?

The witness is considered qualified.

Q Before we refer to -- well, let's for the purposes of going through Mr. Hueni's testimony, we have one Exhibit Nine, and we've tabbed that exhibit with the sheets that we will refer to under each section of the engineering report.

But before we launch into that presentation, Mr. Hueni, could you give us your opinion as to whether you think that the current production situation in the Gavilan constitutes an emergency situation that needs immediate action by the Commission?

A It's my opinion that it does not constitute an emergency situation. It is reservoir performance more or less as we would expect and at this point in time not doing damage to the reservoir.

Q And before we start going through the engineering report step by step, could you tell us what your recommendation will be to the Commission as a result of this engineering study?

A Yes. Yes, I can. With respect to that, what I'd like to do is refer to, I believe it will be the fourth page, because we do have some conclusions that we're presented in written form and following that we have a recommendation presented in written form.

It's prior to the tab that is designated as Producing History. It's the last sheet right before the producing history.

Q Why don't you go ahead and read it?

A Our recommendation is that based on the analysis presented in this report, the maximum allowable for oil should remain as provided by statewide rules, or 702 barrels of oil per day per 320 acre spacing area.

Gas production should be restricted to a volume equal to the maximum oil allowable multiplied by the initial solution gas/oil ratio of 646 standard cubic feet per barrel of oil.

For a 320-acre spacing unit this would allow for a maximum gas production of 453,000 cubic feet of gas per day.

Q Okay. I understand this recommendation is based on the data that you will review with us and I'd like you to begin to explain that data, and I now refer you to the third page tabbed under Producing History and ask you to describe and explain that.

A This should be actually the first tab that you would locate under the section titled Producing History.

MR. STAMETS: Not the third tab.

A Not the third tab.

MR. STAMETS: Okay, we're going to have to get our nomenclature here.

Very good.

A The title title of the figure that we show here is Cumulative Oil and Gas Recoveries as of May, 1986.

The -- what we've shown here are primarily for the wells in the Gavilan-Mancos Pool. We have indicated their cumulative recoveries as of that date in terms of oil and in terms of gas. The legend is such that underneath each well we see first the thousands of barrels of oil produced and then a slash and the amount of gas production in millions of cubic feet produced by that particular well.

We've color coded or attempted to color code the particular exhibit to indicate the areas of greatest withdrawal. Those areas of withdrawal with respect of oil production are shown in yellow. The yellow indicates recovery is greater than 100,000 barrels.

The blue areas indicate more intermediate oil recoveries at this point in time of 50,000 barrels, and finally the orange indicates recoveries greater than 10,000 barrels.

Several wells either recently completed or poorer producers have recoveries currently under 10,000 barrels.

We indicate that there is an area of higher depletion. This area occurs in the south/southwest area of the field, as shown by the yellow. It does tend to follow the northwest/southeast trending pattern for the most part, following along with the basic fracture trends identified by Mr. Ellis in his testimony and Mr. Emmendorfer in his testimony.

We have recoveries in the far southeast area of the field which tend to be somewhat poor and perhaps a deterioration in reservoir quality in that direction.

We would see if we reviewed this that we would have several wells that would be -- that would perhaps stand out.

First in terms of cumulative oil production, the Native Son No. 2, located in the southwest quarter of Section 27 of Township 25 North, Range 2 West, has the highest oil production from the pool, 311,000 barrels of oil with 333-million cubic feet of gas associated with it.

There are three other wells that stand out that are in Section 23 and 26. We have the Gavilan Howard in the northwest quarter of Section 23, which has produced 72,000 barrels of oil with 450-million cubic feet of gas, indicating that that has produced a considerable amount of gas associated with that oil and that happens to be a structurally high well.

We point this out because as has been previously pointed out in the testimony here, that the -- that the Gavilan Howard No. 1 had -- was a dually completed well in the Dakota and Mancos and that there was a problem of mechanical communication between the two strings. That has subsequently been repaired with a gas/oil ratio on the structurally high well has declined substantially.

The second well which is anomalous because of its large amount of gas production is the Gavilan No. 1, located in the northeast quarter of Section 26, Township 25 North, Range 2 West. That particular well has accumulated looks like 78 or 79,000 barrels of oil and 152-million cubic feet of gas.

The large amount of gas attributable to this well, it's very difficult to assign that gas to the Mancos because it is dually commingled with the Dakota and we have really no hard information as to the proportion of gas coming from each of the two zones.

And finally, the well immediately south of that, the Gavilan No. 2, in the southeast quarter of Section 26, that indicates minimal oil production with 18-million cubic feet of gas, that particular well, a well that experienced problems on initial completion, severely damaged, and since the time of initial completion only a minor amount of gas has been produced from that well.

All three of those wells, we believe, have produced a large amount -- well, I don't want to say a large amount of gas, but produced more gas relative to their oil volume that are located at the higher point on structure, are wells that have questionable -- questionable allocation of production to the Mancos.

Q Okay. I now ask you to refer to the next page and -- right under this -- and describe this exhibit and the purpose for which it is shown.

A The next exhibit shows the May, 1986, producing rates expressed in barrels of oil per producing day.

In order to arrive at this exhibit we took the information from the Engineering Sub-Committee in terms of the May, 1986, production divided by the number of days on production, yielding then barrels of oil per producing day.

We plotted that value under -- or associated with each individual well.

Where wells were on for just a very short period of time during the month, indicating perhaps testing operation. we've put those particular values in parentheses.

If we were to review this data, we would see once again that the highest rates associated with wells in the field tend to be for the most part in the south/southwest area of the field -- or south/southwest area of the fields, associated with wells that have had large values of cumulative production.

We also have several wells in the north/northeast section of the field operated by Mallon, which are high capacity wells, as well as a couple wells across in the Canada Ojitos Unit that are high capacity wells.

Some of the data on the Mallon wells is not necessarily representative of their true producing capacity in this particular month, particularly the Mallon Howard 1-8, which indicates -- that is located in Section 1 of Township 25 North, Range 2 West, which indicates a producing rate of 116 barrels of oil per day. This well was restricted by high pressures during this period. Its true capability is on the order of the Canada Ojitos well immediately to the east.

Once again when we go to the southeast area of the field we see wells that are generally of lower rate and we have to assume lower quality as a result.

We have limited information on the Canada Ojitos wells that are two -- well, we have some information on the Canada Ojitos wells that are in this area separating the monocline area from the Gavilan, from the Gavilan Dome area. We do see in general that there are wells, for example, the well in Section 32 of Township 26 North, Range 1 West, in April of 1986 averaged 5 barrels a day.

The well immediately to the south of that in the southeast of Section 8 of 25 North, 1 West, averaged 5 barrels a day.

We do not have any information on the particular well that's located in Section 30 of 25 North, 1 West, and we have an indicated value of 4 barrels a day for the well located in the southwest of Section 31.

We note that to indicate there does appear to be a region of lower producing characteristics or poorer producing characteristics in this region separating the Gavilan Dome area from the monocline.

Q Okay. I'd now ask you to refer to the next page and describe it.

A The next figure is a map showing producing gas/oil ratios expressed in terms of standard cubic feet per barrel of oil produced, based on May, 1986, production as obtained from the Engineering Committee.

We have indicated under each of the wells the producing gas/oil ratio. We've also attempted to indicate the trend that we saw up to May of 1986 in the gas/oil ratio in terms of either an increasing trend indicated by an upward arrow; decreasing trend indicated by a downward arrow; or a more or less constant trend indicated by the dash or minus sign following the gas/oil ratio.

The thing that becomes apparent as we look at this is that there's quite a variability in gas/oil ratios among wells in the field.

We do see in the south/southwest area of the field several McHugh wells, the ET Well, the Native Son No. 2, the Full Sail No. 1, the Janet No. 2, all of which have increasing trends and gas/oil ratio. The -- it would be interesting to note and we can look at this as we go through the production versus time plots for each individual well, that these wells with trends of increasing gas/oil ratio all show increased production in a -- well, recent increases in production.

The high GOR's in this particular area, these are wells that are structurally a bit lower than some of the other wells further to the east and yet the GOR's are higher, we would note that as well.

We'd also note that there are wells in the same vicinity, a little bit to the south, for example, McHugh's well, the Native Son No. 1, located in the northwest of Section 34, Township 25 North, Range 2 West, which has a reported GOR of 184; the well immediately in the southwest quarter of the same section, the Homestead Ranch No. 2, has a reported GOR of 210. This -- these GOR's are less than the solution GOR of the oil, indicating that gas is breaking away from the oil as it approached the wellbore and is leaving the vertical interval in which the well is being produced.

This is going to be one of our evidences that gas segregation is already occurring in the reservoir. This is very clear evidence that it has been occurring at least in these two -- in the vicinity of these two wells.

We also have some increasing GOR's in the north/northwest area of the field. These are wells that have recently come on production and there has been a certain amount of development drilling occurring.

The, once again, wells that are on the crest of the structure are not necessarily the highest GOR wells. There are higher GOR wells down structure. We point out, once again, the anomalous wells that we identified before, the Gavilan Howard, which we said -- which was located in Section -- in the northwest of Section 23, which we indicated had a mechanical problem that was repaired. It now has a very low GOR, or it did in May, and the Gavilan No. 1 and the Gavilan No. 2, which we indicated the Gavilan No. 1 was commingled and the Gavilan No. 2 is a damaged well. Those two wells have enormously high GOR's.

Q Okay, now I think you discussed production statistics for May of 1986. My next question is whether historical trends tell us anything and in this connection I would ask you to refer to the next tabbed exhibit.

A The next -- the next --

Q I guess -- it's a graph labeled Gavilan Mancos Pool Total Cum Production.

A Yes. The next tabbed exhibit, which would follow after the maps, and it should be right in front of you there.

The next tabbed exhibit shows the historical trends in the Gavilan-Mancos Pool. The -- what we plotted here is total pool production in terms of barrels of oil per producing day, in this case for the total pool we used calendar days to be representative of producing days.

We've also plotted, shown on the right-hand scale, gas/oil ratio in terms of standard cubic feet per barrel of oil produced.

The values that are shown by the diamonds are indicative of oil production. The values, and that points to the lefthand Y axis, the values indicated by the X's are indicated -- indicative of gas/oil ratios and that points to the right -- right scale on the vertical axis.

The plot is a semi-logarithmic scale such that the bottom of the graph shows 10 barrels a day, 10 to the second power is 100, 10 to the third is 1000, 10 to the fourth is 10,000.

So what we see when we look at the oil production, is we see a period from when production began in 1982 through about July or August of 1983, where we had production primarily from one well, Gavilan No. 1.

During this period of time the production was relatively low but following that we would see then a substantial increase in oil production as the -- as additional wells are drilled and brought on stream.

The gas/oil ratio, once again, as we pointed out in the Gavilan No. 1, it is a commingled well. It is a bit anomalous. It has a very high gas/oil ratio. We don't know for sure that that can be attributed to the Mancos. It very well could be attributed to the Dakota as well.

Once other wells came on stream we would see that the gas/oil ratio declines down to the first vertical line, which is a value of 1000.

The gas/oil ratio since that time has been first considerably greater than the reported gas --

reported solution GOR, which is in the range of 588 -- we will claim it's 646-- but it is in excess of that value since the late 1983, really.

And the second thing we would note is not only has the gas/oil ratio been greater than the solution gas/oil ratio but it's been relatively constant. It has fluctuated a bit in the range of 1200 up to about 1600 GOR.

The -- as opposed to the previous exhibit by Mr. Roe that we looked at, we have not excluded any wells from this. The Gavilan Howard No. 1 is included in this re-prestentation as is the Gavilan -- Gavilan No. 1.

We do see a relatively constant GOR. In June of 1986 the reported number for gas/oil ratio was approximately 1600; that is in the same order as the other -- other values on this particular plot.

Q I think we've covered everything on this graph. Let's turn to the next page.

A Okay. The next page following. The next page is simply to present to you the data that we used in constructing the plot. It is the producing history, once again obtained from the Engineering Sub-Committee with -- without basically any adjustments made to it.

We show, on here we show first the month and the year. We show then three columns, oil -- or three sets of columns, oil production, gas production, water production, and then finally on the far right we show the number of days produced, which for the total field is equal to the number of calendar days.

The -- we have the monthly oil and gas production shown. We show then the producing rate on a per day basis.

We show the cumulative value in terms of cumulative oil production from the field, cumulative gas production, and then we show the instantaneous GOR at any point in time for the producing life of the field.

That -- that is the first page of the production history.

The second page of the production history summarizes the status of the field as of May, 1986, producing approximately 4,300 barrels of oil per day; approximately 5.3-million cubic feet of gas per day; with an average gas/oil ratio of 1,226.

It's accumulated approximately -- well, somewhat over 2-million barrels of oil to date and slightly over 2.72-billion cubic feet of gas to date.

Q We know that the producing characteristics for different wells in the field vary significantly. Could you review some of these wells with this?

A Yes.

Q And in this direction I'd refer you, I guess, to the next tabbed page.

A Yes. We'd like to skip now to the next tabbed page. What we'd like to do is to look at just a few of the wells to illustrate that wells tend to have variable production characteristics, variable things happening to them. It becomes a bit difficult to talk about the field as one homogeneous entity. It is heterogeneous, at least, in individual well behavior and I think that's important to recognizes.

The next tabbed page is the production history of the Gavilan Howard No. 1. Once again we're presenting this as an oil rate versus time and a gas/oil ratio versus time.

The oil rate is shown by the diamonds; the gas/oil ratio is shown by the X's.

This, as we've said before, was a dual completion with the mechanical -- with communication between the two zones, the Dakota and the Mancos, prepared in April of 1986, as shown by the dramatic decreas in gas/oil ratio in May, 1986, back to a value of 564, which is very close to the solution GOR.

Since May the gas/oil ratio has increased up to approximately 1000.

We wanted to point this particular well out because in was following the repair in the communication in the Gavilan Howard No. 1 Well, a well located to the southeast, the northwest/southeast trend, the Rucker Lake No. 2, which had recently been showing an increasing GOR, and had increased to a GOR on a daily basis as high as 3000, started immediately decreasing upon completion or upon repair of the communication. It is now down to a value of approximately 1400 standard cubic feet per barrel.

This once again indicates communication and a fairly rapid communication along the northwest/southeast trend.

One of the things we might also note is that since communication has existed in this particular well and it has been repaired and we've returned this well to production, we have not produced a large amount of gas back from this particular zone. Once again, the only explanation that we believe is reasonable is that the gas has migrated vertically in the reservoir away from the producing interval in the well.

Q Okay, I now refer you to the next tabbed page, which I think is (not clearly understood), and ask you to explain what this graph shows and why the GOR has increased.

A Okay. The next tabbed exhibit is a similar type plot of rate versus time for the McHugh Native Son No. 2. Once again the same scales apply and the same symbols apply to oil production and gas/oil ratio.

We see this particular well as being a structurally intermediate well. It is in this high depletion area of the field.

We would note that the rate increased in early 1985. This is masked a little bit by the fact that we plot data on a semi-logarithmic scale but it very definitely has increased in 1985, and we note that associated with that same increase we've seen the GOR increase. This is not uncommon that we would see the gas/oil ratio tends to follow rate behavior to some extent of the individual wells, as opposed to the -- as opposed to the structural position.

We would -- we -- as we go through our testimony, we will be indicating that this GOR increase that we observe in wells such as the Native Son No. 2 is a result of slightly higher depletion rates in the vicinity of a particular well or a group of wells, such as we have in the south/southwest area of the field.

We believe that gas/oil migration is occurring. It's already occurring and it's occurring at a particular rate before we ever see any increase in oil withdrawal rate from a given well in a group of wells.

As we have this increase in depletion rate in a particular well the migration rate of gas and oil is initially going to stay the same so if that is the case, then the increased voidage by producing wells such as the Native Son No. 2 has to be taken up by -- by gas. This is going to result in a slightly higher gas saturations, and I use the word "slightly". It's not going to be a significantly higher gas saturation but what's going to happen is it's going to result in reequilibration of the producing gas/oil ratio at higher level.

In spite of the slightly higher level of GOR, we believe that we can show that gas/oil migration is continuing to exist but at a slightly revised level. We are not going to be changing the producing mechanism just as a result of seeing these somewhat higher GOR's in individual wells in high depletion areas of the field.

Q Next I refer you to the final tab under this section and -- which is the Native Son No. 1, I believe, and would you explain that, please?

A The next tab in this section is the tab for the Native Son No. 1. This is a well that is -- we would rate as being structurally high, or structurally higher. Gas/oil ratio has always been low; in fact, it's always been less than the reported solution gas/oil ratio. It indicates gravity segregation is occurring. It's the only way the solution -- the gas/oil ratio could be less than the solution GOR, and we would also note that very recently it's gone down to a value as low as 184 and we might associate that with even minor reduction in production that we've experienced in the last three months prior to May of 1986.

Q Do you know -- Greg, you might go to the map and point out where these three wells are.

A The wells that we just looked at, the Gavilan Howard is located in the northwest quarter of Section 23, 25 North, 2 West.

We looked at the -- I believe it was the native Son No. 2, located in the southwest quarter of Section 27 of 25 North, 2 West.

And now we've looked at the Native Son No. 1. which is very definitely structurally higher than the Native Son No. 2, located in the northeast quarter of Section 34 of that same township.

Q Is there anything further you want to discuss about this graph?

A No.

MR. LOPEZ: We've been going now for about two hours. Do you want to take a break now? We're going to go from this section to the next section and this is a good time to --

MR. STAMETS: It probably is for a fifteen minute recess.

(Thereupon a recess was taken.)

MR. STAMETS: Mr. Lopez, you may continue.

Mr. Lopez, are you ready to go?

MR. LOPEZ: Can't you tell?

Q Okay, Mr. Hueni, I think we've discussed now the producing characteristics of the different wells, some of the wells in the field. I'd like now to have you discuss the fluid properties of the reservoir and in this connection I'd refer you to the first tabbed page under the section labeled Fluid Properties.

A The -- we've presented the fluid property information we used in the reservoir engineering study in the fluid property section. We have in the fluid property section, first a very brief write-up of what we've done but perhaps if we could turn to the first tab, that is a plot of the fluid properties we believe are applicable to this reservoir as a function of pressure.

What we would see is that we have a series of columns here. We have pressure in pounds per square inch on the far lefthand side ranging from a value of 1864 psi, which we assign as being the initial pressure in the Gavilan-Mancos Pool at the mid-point reservoir volume depth.

We follow that with a column titled B-O. That is expressed in terms of relationship of reservoir barrels to stock tank barrels.

We follow that with a column titled R-sub S, which is the solution or dissolved gas/oil ratio, which is in the units of standard cubic feet per stock tank barrel.

We follow that with the gas formation volume factor column, B-sub G, which is reservoir barrels per standard cubic feet.

We follow that, then, with two columns designated as oil and gas vicosities in terms of centipoise.

In order to arrive at our fluid property information, we reviewed the sample information from three wells, the Loddy No. 1, the Native Son No. 3, the Canada Ojitos Unit No. 12-11.

We also have had a chance to review a sample from the Marauder No. 1, which has recently become available.

With the exception of the Naked Son No. 3, remaining fluid samples all appear to be a similar type of oil with bubble point differences affected primarily by cumulative field production prior to sampling, as well as drawdown at the wellbore prior to or during testing.

Inasmuch as we believe that the bubble point pressure has been affected by cumulative field production and/or drawdown prior to testing, we believe that the correct bubble point, the one that actually matches performance when we do our reservoir calculation, that the bubble point should be adjusted upward to a value of approximately 1,770 psi.

Now if we were to look down in our pressure column, we would see then that the second value down, the value of 1,770, is the bubble point pressure, which is only -- well, slightly less than 100 pounds below the initial pressure.

We believe that this matches much better the actual GOR behavior that we observed in the field as opposed to using a much lower bubble point pressure.

In order to adjust the fluid properties to a higher bubble point pressure, that's what we've done, is we've adjusted the fluid properties to a higher -- higher bubble point pressure, using standard engineering practices. We've also adjusted the fluid properties for actual field separator conditions, which has not been done up to this point in any of the analyses that we can determine.

As a result of those adjustments we would suggest that the initial dissolved gas/oil ratio in the Gavilan-Mancos Pool is 646 standard cubic feet per stock tank barrel.

Q Okay. I note that Mr. Roe's GOR was 588 and yours is 646. Could you explain why the two of you differ?

A The reason that we differ is that Mr. Roe's value of 588 is attached to a bubble point pressure of slightly under 1,500 psi, whereas my value of 646 is first attached to a bubble point pressure of more on the order of 1,770 psi, and second, it is also corrected to field separator conditions.

Q Okay, if the true bubble point pressure is 1770 psi, then is it also true that the wells in this reservoir have been operated at a pressure below the bubble point pressure for most of the field's producing history?

A That's correct. That's what we believe.

Q What is the reason we haven't seen extremely high GOR's in this pool on a poolwide basis so far?

A Well, the reason that we believe we haven't seen high gas/oil ratios in the pool thus far is we believe the gravity segregation in a vertical dimension has been occurring since early in the field life. This is consistent, for example, with the information that we looked at producing gas/oil ratio on the Native Son No. 1. We believe that this has occurred.

We would also point out that the gas/oil ratio has been higher than the solution gas/oil ratio for a substantial period of time, indicating that we have been below bubble point but that the gas that has been coming from the oil has been migrating vertically upward to the higher regions of the reservoir.

Q Okay. I'd now like for you to refer to what was introduced as McHugh's Exhibit Three, and explain that this exhibit supports your opinion that the true bubble point pressure is 1770 psi, and that's McHugh's Exhibit Three, Tab D, which consists of a graph.

A McHugh's Exhibit Three presents a plot of pressure and gas/oil ratio plotted versus pool total cumulative oil production expressed in thousands of barrels.

We would note from that, that particular plot, that it's been noted according to the McHugh estimate the initial solution gas/oil ratio was in the range of 480 to 588, shown by the gray area, the gray horizontal area on this particular -- this particular graph.

We would note that after approximately 200,000 barrels of production occur, that we have then have a solution -- or we then have an actual producing gas/oil ratio that is in excess of the solution gas/oil ratio.

We would note also if we looked at the pressure plot that the pressure has declined off -- well, it's just begun its pressure decline.

We believe once again that this -- that our bubble point pressure and our fluid properties are the explanation for why the producing gas/oil ratio is higher than the -- than the solution gas/oil ratio, -- the solution gas/oil ratio, and would drop below the bubble point pressure early in the life of the field.

We also believe that inasmuch as that's true, we've had a constant GOR for an extended period of time as opposed to a rapidly increasing gas/oil ratio. This is indicative of a reservoir which is operating under a gas cap expansion mechanism.

Q And then this then explains the area shaded in pink on the graph, is that right?

A That's correct.

Q Now we have discussed the producing characteristics and fluid property data, have you had an opportunity to analyze pressure data, and in this connection I refer you to the first tab under that section, which is reservoir --

A We have a major tab called Pressure Information and following that, then we have a pullout tab that's on the second page that is a plot, multi-colored plot, Datum Pressure Versus Time.

The datum pressure is the pressure that has been measured at a datum of +370 feet subsea.

We've attempted to include all wells that were -- had data reported to the Engineering Committee.

We would conclude from reviewing this

plot, first, that there is good communication among the various wells in the field. We believe a fracture system is present; that it's pervasive through the north/south area of the Gavilan Dome Field.

We would also note that there are some differences in pressure levels in various parts of the field, that all the values don't fall on a uniform line but there are variations between wells in the field.

We would also note that there is a steeper decline beginning in let's say 1986. In other words, the curve is a bit concave downward and this is simply the result of higher field withdrawals from the -- from the reservoir in 1986 than had occurred previously, and this would be simply that we would basically expect in terms of field performance, normal field operation.

Q Besides this pressure versus time information which you've just discussed, can you obtain any other information from the pressure data that was available?

A There are two other exhibits that we would like to note, or two other figures that we would like to note in terms of pressure information. The second figure that we would like to note is a map of pressures as we have attempted to bring them all to a common point in time. That's May, 1986. Measured at datum of 370 feet, +370 feet, and what we have done, we don't have pressure information on all the wells but we have plotted pressures under individual wells.

We've done this to provide a sense of the fact tha there is a variation in pressure in different areas of the field. It is not a tremendous variation in pressure but there is a variation in pressure.

As we look from -- let's pick, maybe, the Homestead Ranch Well down in Section 34 of Township 25 North, 2 West, we have a pressure of 1360 psi.

We look at the same point in time in the Canada Ojitos Unit well located in the northwest of Section 6, 25 North, Range 1 West, that has a pressure of 1450 psi. At that common point in time we have a pressure gradient of approximately 100 psi between those two -- those two areas.

Q Okay. Do any of these analyses show that the matrix is contributing to production?

A Okay. Well, the pressures that we've looked at are individual point pressures.

In addition to point pressure information, we've had the opportunity to review several pressure build-up tests that have been run on this particular field and that information is presented in the tab following the map of pressure after May of 1986.

Q And that's entitled Pressure Build-up Comparison Summary.

A Yes, that's right, that's titled Pressure Build-up Comparison Summary, Gavilan Field, Gallup Formation.

We have analyzed the various pressure build-up tests that are shown on this -- on this particular graph. We've analyzed it using both type curve analysis for fractured reservoirs, using Greengarten (sic) type curves as well was Horner plot analysis, where the length of time of the test has been sufficient to provide a complete analysis.

I might say that we have analyzed the pressure build-up surveys as opposed to the interference test because we believe the pressure build-up tests are going to give us a much better idea of the average properties in the vicinity of the wells.

The interference tests in a non-homogeneous reservoir cannot be analyzed using the EI, or line source, solution. It will basically -- a test of that tyep will basically reflect only the properties connecting the two wells. It will not represent the overall properties of the reservoir.

Also, in using EI, or line source, solution, we have to assume some degree of homogeneity in the reservoir, and when we assume -- when we use that, when we use that line source solution, we are assuming a greater degree of homogeneity, a degree of homogeneity that would be basically neglectful of the matrix contribution or the contribution of less intensive fractures, and if we use that in the analysis itself, it will give us overly optimistic values for transmissibility in the reservoir.

So we do not believe that the interference tests represent adequately the permeability thickness product of the reservoir itself.

The information here has been analyzed using both a type curve analysis and a Horner plot analysis. The principal column of interest is the column labeled Kh under the type curve analysis and a similar column under Horner plot analysis, and that is the permeability thickness product of the reservoir.

We would see that there are certainly some variations in the results of the analysis. This is to be expected any time that you -- any time that you do pressure build-up analysis. You do have variations if you've used various techniques.

So it is looking at the values that we see both the range of possible values as well as the absolute magnitude of the values themselves.

Under the Horner plot analysis we have a comment test did not reach SLSL -- that means semilog straight line -- when plotted on a Horner plot. It means that the test information is not interpretable using that particular technique.

We once again have looked at the various values of Kh. We note that there is variation from well to well. Some wells have higher Kh values reflecting better reservoir quality; perhaps more intensive fracturing in the vicinity of those wells, while other wells have lower values of Kh, reflecting, perhaps, less intensive fracturing in the vicinity of those wells.

On the average, we would calculate using all of the wells with the exception of the Hawk Federal No. 2, which appears in our analysis, perhaps, a little bit anomalously high on the type curve analysis, we would calculate an average value for transmissibility more on the order of 263 millidarcy feet of permeaiblity under the type curve analysis and 203 millidarcy feet under the Horner plot analysis.

We could, although it's very difficult to assess what net pay is in this particular formation, we could pick a maximum value of pay on the order of 600 feet, which appears to be the primary fractured interval out there, and once again, with -- considering that the fractures are interlaced, that they are pervasive, and we could then divide the average permeability thickness value by a thickness of 600 feet, arriving at average permeability values for the reservoir as a whole in the vicinity of a given well on the order of, maybe, .4 millidarcys.

Certainly fractures are much, much higher permeability but when we lace all of the fractures together, that has a restricting effect.

From this we have concluded that as opposed to a very high value of transmissibility in the reservoir as reported previously, that we have a more modest value of transmissibility in the reservoir itself when -- on an average.

One other point that we'd like to make from the pressure build-up surveys is that in reviewing the pressure build-up surveys, there are several of them that are indicative of dual porosity systems.

A dual porosity system would indicate that there is some type of nonhomogeneous behavior, such as would be -- as could be construed if the matrix was contributing to production along with the fracture system itself.

This is a -- one indication that the matrix is indeed contributing to -- to production.

Q Okay. Have we discussed most of the information you consider pertinent as contained in the engineering report?

A We've can -- we've discussed most of the information on which we did our engineering calculations.

Q Okay. Based on this information have you made any reservoir engineering calculations?

A Yes, we have.

Q Could you refer us to those, please?

A Okay. What we would like to do is turn next to the next clear tab, which is designated as Reservoir Calculations. We would like to skip past the discussion and turn to the first tab, and we're going to talk about each of the individual exhibits in this section in sequence. There should be another -- there should be one exhibit right in front of yours.

The -- the particular plot that we look at first is a plot of datum pressure, once again, pressure measured at +370 feet subsea, +370 feet, from sea level, and it's plotted versus cumulative oil production expressed in thousands of barrels of oil. That's the MBO that we show along -- along the X axis.

We've attempted to plot all of the individual wells.

In reviewing this plot we might note first that we have basically a straight line and a straight line that can be extrapolated back to an initial pressure on the order of 1800 psi.

We might note that this initial pressure is slightly below the pressure that we might expect in the

Gavilan-Mancos Pool had not, had it not been affected by production in the Canada Ojitos Unit.

In the event that no impact had been felt at all, pressure in the Gavilan-Mancos Pool would be on the order of 1880 psi. So in the 20 years of production that occurred in the Canada Ojitos Unit prior to discovery of the Gavilan-Mancos Pool, it affected the reservoir by drawing it down only 80 psi.

If you'll recall, we looked at the pressure gradient going north/south across the Gavilan-Mancos Pool, and we saw the pressure gradient across the Gavilan-Mancos Pool was minimal. It was perhaps, in May of 1986, maybe 100 psi; in fact, not even that significant. And yet we will have, if we look, then, going from east to west from the Gavilan-Mancos area to the Canada Ojitos Unit area, we would see a much larger pressure gradient that's resulted in a very minimal amount of drawdown of the Gavilan-Mancos Pool by the Canada Ojitos Unit.

On that basis, one of the conclusions we're reached is that there is -- that these two pools are operating basically independently of each other and that operations in the Gavilan-Mancos Pool are not going to affect operations in the Canada Ojitos Unit.

We -- we note that from a point in time out to almost 2-million barrels of production, that the decline is represented by more or less a straight line.

The case could be made that since -- that since we've gone in excess of 2-million barrels of production, that the plot of pressure versus cumulative production has become a little bit more concave downward, indicating a steepening in the rate of pressure decline per barrel of oil withdrawn from the field.

We might note that this -- that the point -- that the period of time out to 2-million barrels, we've operated under almost a constant GOR during that period of time, so that we've been taking out a constant amount of oil along with the -- or a constant amount of gas along with the oil.

With a concave downward shape the thing that has changed is that we've had a slightly higher GOR in the last -- in the last few months.

The point that we would like to make from that is the thing that's causing this increased rate of pressure depletion is not the withdrawal of the oil, it is simply withdrawal of more gas with the oil, and in fact in both a solution gas drive reservoir as well as a gas cap expansion reservoir, it is not the oil that causes the problem; it is -- you want to minimize the amount of gas you bring with the oil.

One other point that we would like to

make with respect to this plot is that there has been no break in the pressure trend in the concave upward sense. In other words, we have not seen a very rapid decline in pressure followed by a falling off pressure. It's been more or less, it started off and for quite a period of time it was basically a flat pressure decline we plotted versus cumulative production.

The absence of a period of sharp pressure decline is indicative that we have minimal production above the bubble point. In other words, we were very close to the bubble point initially and we've had gas existing in the reservoir from very early on in the life of the reservoir itself.

Q Based on your analysis of the reservoir and the data used, what is the maximum oil rate for vertical gas (not understood) and --

A Before I go to that --

Q You want to the next --

A -- I'd like to go to the next exhibit.

Q Okay, I thought so, and the next two, I think,.

A Yeah, the next two.

Q Okay.

A The second exhibit --

Q Strike that question, and we'll --

A Yeah.

Q Okay.

A What we've done is we've used the pressure cumulative information in our analysis and in conjunction with that pressure cumulative information, we've also had to try and determine the midpoint of the reservoir volume.

Traditionally the Gavilan-Mancos Pool has recorded pressures at a depth datum of +370 feet subsea.

Working from the structure map drawn on the top of the Niobrara A section to the base of the Mancos Pool, we have accumulated reservoir volume from the crest of that Niobrara section to as deep as the Mancos Pool goes, so we have, then, the highest point of something in excess of 600 feet above sea level down to as low as about 300 feet below sea level, and we see that the fractional volume of 50 percent fractional volume occurs at a depth of 157 feet subsea.

So what we've attempted to do is we've taken all of the pressure information and we've corrected to the appropriate datum, which is the midpoint of the reservoir volume which we estimate to be 157 feet subsea.

So we've also used that in our analysis.

The next figure that we look at a set of rock properties. This particular set of rock properties is, I think we're all aware, there are no specific rock properties that have been -- that have been analyzed either from the Canada Ojitos Unit or for the Gavilan-Mancos Pool. There has been a curve that's traditionally been used in the calculation of performance for these pools and that curve is the one that's shown as curve used in calculation on the dashed line, and this is the same curve that we used.

We might note that as explained in the literature, this would be more severe than a reservoir containing only natural fractures. This would be a reservoir -- typical of a reservoir containing natural fractures but also some matrix, as well.

Nevertheless, we have used the same curve used in calculation that's been done in previous analyses.

If I could get you to turn the next page, then, to the rock properties. The -- the next page is a material balance calculation of oil in place, using the pressure production history that we looked at as the first figure in this particular section. The top half of this particular sheet indicates the information that was input into the model and if we looked under the line that said "control parameters", the value of PI represents the initial pressure at midpoint of the reservoir volume as 1864 psi.

The value of N, which is normally used to represent original oil in place, is set to zero because the program is going to calculate that.

The value of formation compressibility is a value of 10 times 10 to the minus 6 reciprocal psi. This is a value that's been used in Engineering Sub-Committee analyses up to this particular point.

We have also used the table fluid properties that we discussed previously and we've used the historical pressure production information from the cumulative versus pressure plot that we looked at previously.

The producing GOR on the far righthand column represents an instantaneous GOR that is associated with any point in time.

The Gavilan-Mancos Pool is extremely thick and if we reach the bubble point, we are going to reach the bubble point at the highest elevation of the pool initially, and we will still be at pressures above the bubble point deep in the reservoir because of hydrostatic -- because of the weight of the fluid column in the reservoir itself.

So the bubble point is not necessarily reached instantaneously throughout the the entire reservoir thickness. It's reached over a period of time as the overall pressure level in the reservoir declines.

During this period of time we have what's called a partially under-saturated reservoir and during that period of time a conventional material balance analysis as is used in this particular scheme, is not -- is not appropriate. It's only subsequent to the reservoir becoming totally below the bubble point that the values that are reflected in this calculation are representative.

The point at which we have the entire reservoir at a pressure below the bubble point is reached in early 1986, so only the last two values of calculated oil in place as shown on the bottom of the graph are really representative of the true oil in place in the reservoir. These two values indicate an oil in place on the order of 96-million stock tank barrels.

If we would turn the page, what I would like to do is tell you what the sensitivity is to one particular parameter out there on which we have very little information at present, and that is the value of formation compressibility, which is shown under the control parameters line as a value of C-sub F.

The second sheet of material balance calculations was run using a value of the formation compressibility of 5 as opposed to the first sheet being 10. That's 5 times 10 to the minus 6 volume change per unit volume psi pressure change.

The oil in place calculation for this particular formation compressibility is not significantly different than the value we looked at previously. It is a value of approximately 100-million stock tank barrels, whereas in the previous calculation we saw that the oil in place was approximately 96 or 98-million stock tank barrels.

Now if we would turn one more sheet over, we would like to show what the formation compressibility effect, instead of using a value of 10 or a value of 5, using a value of 100.

If we were to review the literature on fractured reservoirs, no matrix contribution, we would believe that the formation compressibility very well might be valued more close to 100 than to a value of 5 or 10, and we can see, then, at the bottom of that page, that this has a significant impact on our calculated oil in place. It reduces the oil in place from the vicinity of 100-million barrels down to the vicinity of 60-million barrels.

For the purposes of further analysis, I've used the value of 100-million barrel of oil in place. Using a smaller value of oil in place would give me an answer that would indicate that we would have had even more gas evolution and gas segregation than what I'm about to show you.

The next page is a little bit different. Instead of using a material balance calculation of oil in place, we are now specifying the oil in place. It's specified under the second value of the control parameters, under the value of capital N that stands for oil in place. We specified a value of 100-million barrels in this calculation.

We've used the formation compressibility of 10 times 10 to the minus 6.

We've used the same fluid properties and now in order to predict how a solution gas drive reservoir would perform, we have to input in the rock properties that we are going to assign to this particular reservoir, and really the only rock properties that we need are the table values of gas saturation, shown as S gas, ranging from zero up to a value of .2, and the ratio of gas relative permeability to oil relative permeability, shown as going from zero up to 7.3.

With that information, the program can perform a conventional solution gas drive analysis and predict the -- or predict what the -- or what the gas/oil ratio behavior would be for this type of reservoir and the bottom section of the -- of this calculation sheet shows that.

We show on the lefthand side pressure. We show the amount of incremental and -- incremental production in terms of oil in stock tank barrels and gas we have in cubic feet that occur for each pressure decrement from an initial pressure of 1864 down to a pressure as low as 1021.

We show the cumulative production in terms of stock tank barrels and gas in terms of MCF. We show at these same pressure points what the producing gas/oil ratio would be and we show what the gas saturation, expressed as a fraction, would be. This gas saturation would be the gas saturation within the oil zone itself were we building a gas -- a high gas saturation in the reservoir.

This information is calculated for a solution gas drive field.

Now if you will turn the page, what we would like to show is why we don't believe this is a solution gas drive field.

We agree that pressure has dropped below the bubble point, that we've created free gas, but we believe that the gas has migrated away from the wellbore, it's not being produced from the wells. In other words, we are forming a secondary gas cap in the reservoir itself, and the reason we believe this is a comparison of what's actually occurred in the Gavilan-Mancos Field as opposed to what would be predicted for the Gavilan-Mancos Field.

We have on the X axis the cumulative oil production from the field, or the pool.

We have on the Y axis a scale that represents both pressure in psi and gas/oil ratio in terms of standard cubic feet per stock tank barrel.

We have four curves shown on here. The first is the predicted pressure versus cumulative oil production. That's shown by the square boxes beginning at a pressure of about 1864 and then sloping downward across the plot.

We have the actual pressure comparison to that; actual pressure comparison is slightly higher but very close.

We have the predicted GOR. Our predicted GOR for the first 200,000 barrels of oil would be a value of the solution GOR, which is -- we ascribe to be 646, and then following that, we would create a gas saturation in the oil zone and the predicted GOR indicates that we would go to values much higher than the solution GOR. In fact, we get up to values as high as 10,000, or almost 10,000, by the time we reach 3-million barrels of oil from the pool.

We've plotted the actual GOR here. The actual GOR behavior is somewhat high because we've included the Gavilan No. 1 GOR in there and in fact, if we were to take the data from Mr. Roe, as shown in Exhibit Three, again, we would see that for the first 200,000 barrels of oil Mr. Roe shows no increase in gas/oil ratio above the solution gas/oil ratio, and that would certainly be in agreement with what our predicted numbers are, as well.

The actual GOR behavior has been -- has

been in excess, initially in excess of the solution GOR, indicating the presence of some free gas but it has not increased dramatically as we expect in a solution gas drive reservoir. It has basically been a level trend. The value, the June value of 1586 would certainly be a continuation of this trend and we do not see the rapid gas/oil ratios predicted for a solution gas drive reservoir.

For that reason we have concluded that this reservoir is performing as a gas cap expansion reservoir with the source of the gas being gas that is coming out of solution from the oil as the pressure declines, gas migrating vertically upward to the top of the formation, and that is keeping us, keeping the gas/oil ratio low.

Okay, if we would turn to the next exhibit, knowing that gas is moving vertically upward we have to consider what's going to happen when it reaches the top of the formation itself.

What we have done on this particular map is to pick a point in the Gavilan-Mancos Pool, a center point, we used Gavilan Howard No. 1, located in the northwest of Section 23, Township 25 North, 2 West. We picked that as our center point and then we've measured the angle of dip to various wells located throughout the pool area.

First we have calculated the angle of dip in the direction of Mallon wells to the northeast toward the

Howard 1-11. It has a vertical change in elevation of 129 feet for a distance of 15,475, indicating a dip of .5 degrees.

Moving then to the west in the vicinity of the McHugh Loddy Well, we have a vertical change of 265 feet over a distance of 16,400 feet, indicating a dip of about .9 degrees.

We have to the south between the Gavilan Howard and the Oso Canyon Well, located in the northwest of Section 11, Township 24 North, Range 2 West. We calculate a change in elevation of 35 feet over a distance of 21,800 feet for a dip of .09 degrees.

As we move right to the flanks of the structure I would have to say that it would be possible that we might have slightly -- slightly higher degrees of dip along the flanks, along the very extremes of the structure, but through the majority of the structure of the Gavilan-Mancos Pool we have very minimal dip at all.

We've also noted for the Canada Ojitos Unit on -- in Township 25 North, Range 1 West, we've taken a sampling of the dip going down structure from one of the -- what appears to be one of the gas injection wells, where crestal (sic) gas was injected, and we notice in this case that we would calculate a much higher degree of dip, 6.5 degrees. Certainly the dip in the Canada Ojitos Unit varies as well, but the area where the gas has been injected, primarily is region where we have a much higher dip.

The significance of the dip of the formation is that it controls the lateral tendency for gas to move across the field. In the case of the dips that we're talking about in the Gavilan-Mancos Pool, as compared to the 6.5 degree dip that we've looked at in the up structure part of the Canada Ojitos Unit, the Canada Ojitos Unit has between 7 and 55 times the tendency of the Gavilan Pool to allow lateral migration. So, in other words, Gavilan has very minimal ability to transmit gas laterally across the structural nose.

Okay, well, moving from, then, the map showing the dips of the formation to the next exhibit which is a schematic of gas segregation as we believe is occurring in the Gavilan-Mancos Pool, we have shown a representation, not of any particular set of wells here, but we've shown two wells located approximately 2640 feet apart, producing from a zone that's approximately 600 feet thick.

We've tried to indicate the .5 degree angle of dip but I'm afraid that's gotten lost in the thickness of the upper line that indicates the top of the Niobrara A. In other words, it looks almost horizontally when you look in this perspective.

We -- what -- what we would note from

this particular exhibit is that in order to have a gravity segregation reservoira, which then turns into a -- that then forms a secondary gas cap, we have to have a pressure that drops below the bubble point and we do have to have free gas released from the oil in the oil zone.

That gas, as we show in the -- by the two vertical arrows, will migrate vertically upward. At the same time the gas migrates vertically upward oil will migrate vertically downward to take the place of the gas.

And that's what we're to promote as much as we can, would be the creation of the secondary gas cap, which would then displace oil downward through the reservoir to be produced by the wells.

One of the difficulties we might note immediately is that many of the wells in the Gavilan-Mancos Pool have been completed throughout the entire section so that in taking gas from a particular well we really don't know if it's coming from the top of the formation or if it's coming out of the oil zone itself. This is a problem that is going to have to be confronted by the operators of the Gavilan-Mancos Pool. They are going to have to -- try try and minimize the amount of production that²s withdrawn from the upper area of the reservoir.

Certainly any kind of allowable situation tied to low GORs will promote -- the economic interest would promote attempting to minimize the gas withdrawals from this up-structure area.

We would note that the gas migration is controlled -- it's not so much how fast gas can move vertically upward as it is by how fast oil can migrate vertically downward and the rate at which oil can migrate vertically downward is affected by the gas saturation within the oil zone itself. It doesn't have really much to do with the saturation in the gas cap. It's simply the saturation in the oil zone.

And what we would -- what is true for a gas cap expansion reservoir, if you produce a reservoir such as this at higher withdrawal rates, it's going to result in higher oil zone gas saturations, which are going to tend to slow down the oil migration rate.

If we slow down the oil migration rate then the amount of gas that moves to the wellbore in conjunction with the oil, will actually increase and we will have a bit higher value of gas/oil ratio than we would have otherwise.

The fact that we have a higher gas/oil ratio does not mean that we are -- it should not be implied to mean we are no longer having gas migration move to the crest of the reservoir. We can go to a higher gas/oil ratio in individual wells while we still have substantial amounts of gas moving up structure to form the secondary gas cap. If we produce at higher GOR's we will take gas from the reservoir a little bit faster and the pressure will go down a little bit and the production rate of individual wells will decline a little bit faster than would otherwise be expected, but the ultimate recovery will be affected by the displacement of the oil zone by the secondary gas cap.

We have used a model of -- for gas cap segregation, a computer model of it, and we have attempted to duplicate the field production between discovery and April, 1986, and from that model we would imply that the oil zone portion of the Gavilan-Mancos Pool has a very low gas saturation on the order of about 1-1/2 percent.

We would also imply that approximately, while we've produced about 2.7-billion cubic feet of gas from the reservoir, about 1.2 BCF of gas has moved vertially upward to the higher, the top of the formation.

Q Greg, you've referred several times to gas migrating to the upper portion of the reservoir. Isn't really what you mean, that the gas is moving to the upper portion of the formation, not necessarily up structure?

A That's true. I should be corrected in the sense that I uniformly mean that it's migrated up vertically and it has not moved laterally across the field to any great extent because of the absence of sufficient structure for that to occur.

Having indicated that the Gavilan Pool is a gas cap expansion reservoir, that this has been occurring in the past, will continue to occur in the future, that this should be promoted, that it will result in maximum oil recovered from the reservoir, the question then becomes what is the maximum rate we can take oil from the reservoir while still promoting this vertical gas segregation, and my next sheet following the schematic of gas segregation includes the results of the calculations that I've used.

We indicate the formula that calculates the maximum oil rate for vertical gas segregation. This is the identical formula to -- to the formula used by Mr. Greer in his calculations, a little bit different nomenclature but we've explained what our various values are.

What we've done is we are now considering -- we're considering vertical gas segregation, so it is moving across the entire surface area of the reservoir, so for a particular well spaced on 320 acres, it's moving through our cross sectional area of 13.9-million feet. That's what we show by the parameter A.

We're using a value for permeability for this rather than just a single fracture connecting two wells, we've used the average permeability for the reservoir. In fact we've actually decreased it from what we calculated to be the average for this lace network. We've calculated a permeability value of .1 millidarcys.

The value of Delta Y, which is really, it's a difference in the specific gravities of oil and gas, those are obtained from fluid properties.

The angle A, we have sine of the angle A, A is the angle at which the flow will occur, and it will occur vertically so it's a 90 degree value. That is the most efficient way that the gas can move. The sine of 90 is a value of 1.0, that's the maximum value for that term.

We've used a pressure of 1500 psi to obtain the fluid properties that we show below, including oil viscosity, which is designated by Mo, gas viscosity, Mg, oil formation volume factor Bo, gas formation volume factor, Bg, dissolved gas/oil ratio.

What we'd like to do then is show the results of our calculation down here and I'd like to look first at the gas saturation value of .015, which is 1.5 percent. That's the value that our gas cap segregation model indicates is currently applicable to the oil zone, to the oil zone. It's the gas saturation in the oil zone.

We use our rock properties that we've obtained that we have shown previously, results in a value of KgKo of .03 and consistent with that is a KRO value of .1. Similar to what Mr. Greer says, the presence of free gas in the fracture will tend to restrict the -- the flow of oil in that fractures itself.

So substituting those values into the equation, we see that the maximum oil production rate at which we can still expect to have gas segregation occur, is 634 barrels a day and it's high because we're migrating vertically upward.

The oil zone, producing oil zone saturation, or oil zone producing GOR can be calculated with a similar formula and it is a value of about 1335, which does appear to be representative of the oil zone's producing gas/oil ratio at the present time.

So we have calculated for various values of gas saturation in the oil zone itself, we've said that the gas saturation, if we go to higher withdrawal rates, the gas saturation of the oil zone can increase a bit and it will be reflected in higher producing GOR's, such as we see for a 2 percent gas saturation, we see a GOR of 1850; for a 4 percent gas saturation we see a GOR of almost 4700; well, with those higher -- higher gas saturations and higher GOR's and the maximum oil production rate that can be sustained while still promoting this segregation of gas and oil, decreases a bit. It goes from the 634 number down to -- to in the range of 400.

If we have no gas saturation at all we

less than a 1335 GOR, that just means that the gas saturation in the vicinity of that particular well was a little bit less than 125 percent, and it could be permitted a somewhat higher -- it could be permitted a somewhat higher rate, but we believe, once again, that including a factor for a safety factor in there, that we could appropriately substitute in the 702 barrels of oil per day in conjunction with the 646 value for oil zone producing GOR, produce at that rate, and do no damage to the reservoir whatsoever.

Q Have the rates to promote gravity segregation calculated in your analysis, are they comparable to rates calculated previously, and in that connection I refer you to what's marked as Exhibit Number Ten?

A In order to provide a check to the engineering analysis that we've done, which we've tried to direct to the specific conditions of the Gavilan-Mancos Field, we -- we have attempted to take data previously presented for the Canada Ojitos Unit and adjust it because there is a very difference -- very definite difference in the -- in the Canada Ojitos unit from the Gavilan-Mancos area. We tried to adjust for the difference and we've attempted to take the rate, producing rate information obtained from this previous hearing and -- and adjust it to the conditions of the Gavilan field in comparison with the conditions of the Canada Ojitos Unit to see what kind of producing rates would be predicted from the Canada Ojitos Unit data.

We've used data from an exhibit titled Benson-Montin-Greer Drilling Corp. Exhibits in Case Number 7075 before the Oil Conservation Division of the New Mexico Department of Energy and Minerals, West Puerto Chiquito Field, Rio Arriba County, New Mexico, November 24th, 1980.

In this exhibit the presentation has included in this exhibit a graph under Section 3 that's shown as Figure No. 5, titled Gravity Drainage Rate, West Puerto Chiquito Field, and it is for conditions of formation dip of 400 feet per mile.

In the case of the West Puerto Chiquito, gas is being injected and displacing laterally across the field from the up structure to the down structure area.

In the case of Gavilan-Mancos, the gas is migrating vertically upward through the cross sectional area of the reservoir to form a gas cap at the top of the producing interval.

So we would have to make some adjustments to Gavilan, or to West Puerto Chiquito to be comparable to the Gavilan-Mancos Pool.

In order to -- in order to make this comparison we also have to select from the plot presented in the exhibit. We have to select a value of the relative permeability to oil thickness product and we have used the lowest value that we have in our analysis, which was a value of approximately 48 millidarcy feet.

If we had higher values of KoH as our pressure buildup surveys imply and certainly as the data from the Greer exhibit imply, then we would have higher producing rates capable while maintaining this gravity segregation mechanism.

The adjustments to the previous studies required, that are required for differences, are required for differences in angle of displacement. West Puerto Chiquito displacing down along the monocline as opposed to Gavilan, where we're displacing vertically, and we would also have to compensate for the cross sectional area through which displacement occurs. In the case of the Puerto Chiquito field we were displacing along the length of the monocline multiplied by the thickness of the formation.

In the case of Gavilan we were displacing vertically downward through the horizontal cross sectional area of the reservoir.

If we take the data presented, which is presented in terms of gravity drainage rate, barrels of oil per lineal mile, and we make the proper adjustments to our comparison, then Case 7075 extended the Gavilan with no free gas present. Where our analysis says we would limit it only to the 702 barrels a day, Case 7075 indicates a rate of 950.

With free gas present where we would indicate, depending on the producing oil zone GOR and the gas saturation, our analysis would be in the range of 400 to 630. Case 7075 would be a value of 550.

So we feel confident the values we've come up with here are values that for this sort of field are analyzed in a manner comparable to the analyses that have been performed in other fields in the area.

Q Okay. Now I'll ask you have you calculated the effect of allowable reductions under various scenarios to the Gavilan-Mancos Pool, and I think you have and those are under Equity Calculations. You want to go right to Exhibit Eleven?

A Yeah.

Q Okay, and narrate briefly Exhibit Eleven to the Commission.

A Okay. Exhibit Number Eleven contains some examples of economics that we've prepared, that we tried to keep it as simple as we could think to do.

We have selected a recovery that is certainly -- well, perhaps it's going to be typical of some of the wells either drilled or to be drilled.

We selected a recovery of 250,000 barrels of oil and from an actual engineering analysis of the amount of gas we could expect to produce with that, that oil, we've included a gas volume of slightly over 1-billion cubic feet of gas.

What, the purpose of our exhibit, our analysis was to investigate was what various curtailments would mean to the economics of -- of a particular well over its producing life and the basis that we've set this on is that if we establish an oil allowable of some particular value, there is a finite probability that that allowable will extend throughout the life of the field.

So we have analyzed, using three different rates, daily oil allowables of 200, 400, and 702 barrels, with various GOR limits of 1000, (not understood), and 646, implying allowable gas rates varying from 200 up to 453 MCF per day.

We started each of our wells off with an initial GOR of 1500 standard cubic feet per barrel and what we find is that the economics are such that the maximum initial oil rates are then limited by the gas production to rates of 133, 267, and 302 barrels of oil per day, respectively.

We've made the assumption that the well we're drilling is a well capable of 700 barrels a day or more.

The economic parameters we've used are $11.00 per barrel, $1.70 per MCF, operating cost, $3100 per month per well, an investment of $550,000 if we had to drill the well.

We -- we have obtained this information from -- from Mesa Grande Resources and some of the wells that they operate.

We then show on the succeeding three pages, we show the individual cash flow analyses for each of the three cases that we're considering.

We show on the first set of columns we have on the far lefthand side, well, this very first page is for our example well at 200 barrel a day, 1000 GOR production limit, and we have then for -- on the lefthand side the month and year. We have, as we move across, various production statistics including average producing rate, starting at 105.6 barrels per day. The average gas rate is further across on that set of columns and it's a maximum value of 200 MCF per day.

We go then to the second set of columns where we have applied an 80 percent net revenue interest and used our oil price and gas price to (not understood) constant price economics.

We've determined then the various revenue streams, the liquid and gas revenue streams.

And then on the bottom set of columns we've subtracted off the net severance tax by year and resulting further across the page in the total, net total income we've also subtracted off net operating costs. We then arrived at net total income. We subtracted off the investment to arrive at net cash flow and then we've discounted that net cash flow at various discount factors to arrive at present worth.

Present worth data is shown in the lower righthand corner of the page. It's present worth of net cash flow before federal income tax discounted at various rates and when we select a discount factor, normally when we write constant price economics as we do for Securities Ex change Commission evaluations, we select a discount factor of 10 percent.

So if we selected the 10 percent value the present worth of this particular well would be 1,134,000 barrels -- or dollars, I'm sorry.

If we skip over to the final page, which is our 702 barrel, 646 GOR production limit, we can see our analysis results in a much shorter well life. We're still limited by gas producing rates for quite a period of time during that that period -- well, during the well life.

I guess I should also note that the gas/oil ratio we've increased. We haven't left it at 1500 for the entire life of the field. We've increased it from the beginning to the end because I think there is a high probability that in spite of operator's efforts to contain gas in the higher part of the reservoir, it's not always going to be successful, so we've increased the producing GOR. We've come up with this limit according to the average gas production. We've completed the economic analysis in the exact same fashion, and at the bottom we've arrived at a present worth net cash flow discounted at 10 percent, of $1,857,000.

So by restricting production we potentially suffere a large loss in present value of the product.

The thing, the other thing to note on this is that we have used the same recovery for all three cases, since according to our analysis, if we limit production to 702 barrels a day, 646 GOR, we are not going to suffer any loss of recovery as compared to restricting it to 200 barrels a day with 1000 GOR.

Q I think I'd like you to elaborate on that last point. Is it your opinion that your recommendation will result in more ultimate recovery from the pool than the McHugh-Greer recommendation?

A Well, I -- they will both result in the same magnitude of recovery from the pool. In either case we've identified a rate which we believe is the proper rate which should not be exceeded in the pool. In our analysis we've tried to direct it straight to the Gavilan-Mancos Pool with the specific properties of the Gavilan-Mancos Pool, and we've tried to accoount for the things that we actually see happening in the field, and we do not believe there will be any loss in ultimate recoveries.

Q Okay. I'd like you to -- have you had a chance to review Mr. Greer's proposition that oil in place is related to the cube root of productivity or permeability, which is one of the bases on which he justifies a lower barrel a day allowable, and if so, would you comment?

A Yes, I have, and if I could I'd like to refer to that particular exhibit.

MR. STAMETS: Mr. Lopez, how much longer?

MR. LOPEZ: We're just about through.

A With respect to the question regarding the relationship of porosity and cube root of permeability as expressed in Mr. Greer's testimony, I'd like to refer to the BMG Exhibit Number One, Section D, and it would be the sheet following the gold sheet, the one that has both a range for sandstone and a range for fractures.

The comment that I would have on this particular sheet is that, yes, there is a defineable relationship between fracture permeability and porosity provided you assume both the intensity of fracturing as well as the width of fracturing, and that is an exact engineering relationship.

But the other point I'd like to make is that this entire yellow band represents the values of possible relationships of fracture permeability to porosity and any particular well in here, should fall anywhere within this yellow band and it doesn't mean that all wells will follow along a given trend. In fact, in my opinion it would seem that rather than assuming a given intensity of fracturing with the varying width of fracturs, as Mr. Greer has done by selecting the upper line that shows 100 fractures per foot, it would be equally valid to assume that we have a constant width of the fractures and we just have a different intensity of fracturing in different areas of the field, and if that is the case, instead of drawing a line that follows along that 100 fractures a foot, we could draw a line that's more parallel to the dashed line such that run through, for example, depict the value along the 100 fractures per foot line, the value of width of .001, and if we then move down to the 10 fractures per foot line and pick that same width, steeper line than -- than using just this 100 fractures per foot.

In fact, if we were to take the dashed line, we would come up with a relationship of porosity to permeability that would be a much more one to one type relationship than this cube root relationship we're talking about. The cube root is simply a convenient assumption, based on the assumption that every part of the field is fractured with the same intensity.

Q Okay. In summary, then, I'd like you to explain the conclusions you've drawn as a result of your engineering study.

A Okay. Well, I'll try and be brief on this. The very first sheets on the -- in the report contain our conclusions.

MR. LOPEZ: And if there is no objection, I'd just like to have those included in the record and we won't review them for purposes of brevity, if you would be so kind.

MR. STAMETS: Okay, we'll have those included in the record.

MR. LOPEZ: Okay.

Q Is it your opinion that if the Commission were to adopt your recommendations that would be in the interest of the prevention of waste and protection of correlative rights?

A Yes, sir.

Q Were Exhibits Nine through Eleven prepared by you or under your direction and supervision?

A Yes, they were.

MR. LOPEZ: At this time we'd offer Exhibits Nine through Eleven.

MR. STAMETS: Without objection they will be admitted.

Q Do you have anything further?

A Nope.

MR. STAMETS: This looks like an excellent time to recess the hearing until 1:30.

(Thereupon the noon recess was taken.)

(Thereafter at the hour of 1:30 o'clock p.m. the hearing was called to order and the following proceedings were had, to-wit:)

MR. STAMETS: The hearing will please come to order.

I presume there may be a couple of quesions of Mr. Hueni.

MR. LOPEZ: Before we begin cross may I ask him one question?

MR. STAMETS: Yes.

MR. LOPEZ: Mr. Hueni --

MR. STAMETS: One more question?

MR. LOPEZ: One more question.

MR. STAMETS: As long as it's very short.

MR. LOPEZ: The answer will be short and I think the question will be, as well.

REDIRECT EXAMINATION

BY MR. LOPEZ:

Q We didn't discuss how long your recommendations should remain in effect if the Commission were to adopt your recommendation as to the restriction on allowables in the Gavilan-Mancos Pool.

Do you have an opinion as to how long they should remain in effect?

A Yes. We believe that inasmuch as no damage would be done to the reservoir under our allowable system, we recommend that the allowable be maintained for a period until March of 1987, or whenever the Commission next chooses to review the spacing for the Gavilan-Mancos Pool.

Q Thank you.

MR. STAMETS: Let's go off the record a minute.

(Thereupon a discussion was had off the record.)

MR. STAMETS: Does anybody have more questions of the witness?

Who's first? Mr. Carr.

CROSS EXAMINATION

BY MR. CARR:

Q Mr. Hueni, today, in the early portion of your testimony you spent some time explaining how you'd calculated what you considered to be the bubble point of the reservoir.

If I understand your presentation, and I very well may not, the bubble point, as I gather, is an important factor in your interpretation of the Gavilan reservoir, is that correct?

A We, in studying the Gavilan reservoir, used a set of pvt properties that included the bubble point of 1770.

Q And that bubble point is an important factor in that interpretation.

A It is not absolutely critical to the answer, but yes, we -- we investigated a variety of possibilities for the fluid properties and we concluded after that investigation that 1770 was the most accurate one.

Q If you should discover that that bubble point was substantially different than that 1770 figure, that would have an impact on your interpretation of the Gavilan, would it not?

A It would have a bit of an interpretation but it wouldn't change the general conclusions.

Q Now, how many barrels of oil did you estimate were in place in the Gavilan, or did you?

A We presented three cases which were dependent on the formation compressibility. The cases ranged from a high of 100-million barrels in place to a low of around 60-million barrels in place.

Q And 60-million was the figure you derived using what, 100 times 10 to the -6, or something like that?

A That's correct.

Q Do you have any idea what area within the reservoir this production is coming from? Have you defined an area which is contributing?

A No, we have not attempted to do volumetrics because we didn't feel that that was particularly possible.

Q So you have not estimated the number of acres that may in fact be contributing.

A That's correct.

Q You haven't based any of your calculations on the 30,000-acre figure that was utilized by the study committee?

A No, it's not.

Q Have you, in your calculations, estimated the number of wells that are going to be required to produce reserves in the Gavilan?

A No, I have not.

Q Have you done any work based on an assumption that you would utilize, say, one well to each 320 acres? Has that been utilized in any of your --

A The only place that the assumption of one well per 320 acres is made is in calculating the maximum rate at which gravity segregation can occur.

Since the segregation occurs through a cross-sectional area, in a horizontal sense we've used a 320-acre value so that the segregation numbers are applicable to wells drilled on a 320-acre spacing.

Q Now, you've -- have you done any calculations -- you have estimated, have you not, the recoverable barrels of oil available to each well?

A No, I wouldn't say that.

Q I thought in your economic calculations you had utilized a figure of 250,000.

A We used a figure of 250,000, which we thought would be representative and I guess to expand on that, one of the, say, a very quick approach to estimating reserves might be to take the pressure versus cumulative production plot and extrapolate that on a linear sense to obtain a value of about 12.5-million barrels of recovery.

Now, once again we still have that uncertainty as to oil in place because of the uncertainty as to the formation compressibility, but -- so the 250,000 barrel number appears as a reasonable possible number for a typical well out there.

Q And what -- what recovery factor were you using?

A We didn't use a recovery factor because we didn't have -- once again we estimated ultimate recovery only through economic calculations. We didn't have to estimate ultimate recovery to determine damage, so we estimated that only for -- for the economic calculations and that recovery factor, if you want to calculate a recovery factor, means that you have to know the absolute value of oil in place.

So the 12.5-million barrels, if you want to use 100-million barrels, represents a 12.5 percent recovery factor.

If you want to use 60-million barrels, it represents, obviously, a greater recovery factor.

Q And you were using 250,000, is that not correct?

A I was picking that as a typical recovery on which to base an economic calculation.

Q And there was no -- and you were assuming that was for wells on 320 or not.

A That was for a typical well out there. We have already seen wells that have accumulated 330,000 barrels. We know that additional wells have been drilled that have yet to come on production, so there's going to be a very wide range of potential recoveries from wells out there and to pick a case to illustrate the effect of the different allowables, we picked a value of 250,000, believing that to be a reasonable intermediate value.

Q Now in doing your work did you accept the interpretation of Mr. Emmendorfer as to the fracturing situation in that reservoir?

A I believe the reservoir is indeed fractured, that's correct.

Q And did -- do you accept his conclusions, if I understood them, that the vertical permeability was approximately equal to the horizontal permeability in that fracture system?

A I don't know if he concluded that the vertical was equal to the horizontal but I believe that the data supports that there is significant vertical permeability.

Q Have you considered the possibility that the fractures in the area may be associated with bedding planes or interbedding shales and sandstones?

A I've personally seen several cores where the fracture extended through the shales as well as the sandstones.

Q Is it your opinion that the vertical fractures extend throughout the 600-foot Gavilan interval?

A I think there is a good chance that they extend; they may not be one continuous fracture from top to bottom but I believe that they intersect. In other words they form a network that extends from top to bottom.

Q And so this would be a -- would make that one reservoir from top to bottom, not a stratified reservoir.

A In a gross sense, that's correct.

Q Don't want to be gross here.

A I understand that.

Q My question really is, if that's the case, then why, why are the wells not perforated throughout this 600-foot interval instead of as they are, just in these particular zones?

A Well, several wells are perforated throughout the entire section.

Q Could you identify those wells?

A Well, we have in our exhibits, we have shown in back of the -- under producing history, we have behind the first three maps which we have indicated with tabs, we have completion information on -- on various of the wells that are in the Gavilan-Mancos Pool.

These wells, several of them, I think, and perhaps we could pick --

Q Just a minute, what tab are you on now?

A I'm sorry, I'm not on a tab. I've gone to the page behind the third tab and it says Completion Information on that page.

It's possible that -- does it say Completion Information?

Q Completion Information. We're with you.

A Okay. There are several -- well, there are wells in which we had information listed on this page along with the perforations, the top and bottom of the perforated interval.

If we were to look, for example, it would be on the second page, we picked perhaps the Mallon Johnson Federal No. 12-5, the top of the Niobrara A is on that well, which is three-quarters of the way down the page, the top of the Niobrara A is located at 6922.

The well is perforated from 6777 to 7592. The well has been fraced, establishing vertical communication between the actual perforations.

Q In that particular well is it perforated uniformly through that section?

A I don't believe it's probably perforated uniformly but it has been fracture stimulated in such a manner that we would expect vertical communication.

Q And if you, the lower resistivity zones in the well, now we're talking about something in the upper portion of the interval, were those lower zones also perforated in the Mallon well?

A I -- I can't tell for sure if they were or not. I don't know.

Q If all the interval was not communicated vertically, how would that affect your estimates of the pool's recovery?

A Well, if it was -- if it failed to communicate vertically, then I would see -- well, first, I guess I'd have to back up (not clearly understood) because I believe the frac jobs on these wells plus the existence of fractures in the core would indicate that it is communicated vertically.

Q Now let me take you forward. My question was if it was not all communicated vertically, what impact would that have on your estimates of pool recovery?

A Well, I believe if it doesn't have vertical communication, I believe that the pool is not going to produce in any fashion other than a solution gas drive reservoir, and the reason is that the only method for enhanced recovery is some sort of injection, gas injection scheme, relying on the natural thickness of the formation, and if that thickness of the formation couldn't be utilized in enhancing the recovery, then I believe that the reservoir would produce strictly as a solution gas drive reservoir, and I believe the data doesn't indicate that it has thus far or that it will.

Q If you're called upon to inject gas into this reservoir, do you know of any way that could be accomplished other than by unitization of the reservoir first?

A I would imagine not.

Q Now, if I understood your testimony, your build-up tests indicated a two porosity system.

A I would say that they showed some indications of a two porosity system, yes, that's correct.

Q Would not just the stratified nature of the reservoir possibly be an anomaly that would give you that result?

A That's right.

Q In terms of vertical communication, have you done anything in terms of testing to establish that, setting a packer or running any tests to determine whether or not there is in fact vertical communication?

A The evidence we have of vertical communication is in part the presence of the gas zone in the Marauder, the absence of higher GOR production in several up-structure wells.

In terms of actual testing, to the best of my knowledge no operator has undertaken any kind of vertical -- vertical testing.

Q As to the pressure build-up test, back to that for one more question, couldn't the actual production and interference from other wells in the area affect that data?

A I don't believe that it substantially has. They appear to be reasonably -- reasonable tests with reasonable interpretations.

Q Now, as new wells were drilled in the Gavilan area and drilled throughout the area, I understood your testimony to be that they had encountered a pressure that was actually below the initial reservoir pressure for the entire Mancos formation in the area. Is that correct?

A Well, there would be indications that would be a true statement to the extent that there are indications that the expected pressure in the Gavilan Pool would be on the order of maybe 1880 psi, whereas the actual pressure might have been on the order of a datum of 370, where the actual pressure might have been on the order of 1800 psi.

Q And wouldn't that also be an indication that there was drainage from other wells in the Gavilan? As compared to the Canada Ojitos, wouldn't be evidence that the Gavilan had in fact experienced some drainage from the Canada Ojitos wells?

A Very minimal drainage, yes.

Q If we go within the Gavilan itself and we drill a well and encounter a pressure that is below what you'd anticipate initial reservoir pressure to be, here again the same question, that would indicate that that area has been previously drained by offsetting properties, isn't that correct?

A Our testimony has indicated that we believe there is good communication north to south across the Gavilan Dome area; very limited communication east to west.

Q Just a minute, please.

One last question and then I think that's all the coaching I'm going to get, do you have any pressure information on any individual test data or any individual tests taken on one of the lower zones?

A No. I do not believe -- I have the test data taken from the engineering subcommittee analyses and I'm not sure if any of those would be -- if any of those represent the lower zone.

Q Okay, and then just a couple more.

A Okay.

Q I think Mr. Lopez was, I think, being sure that the record was clear on this, you testified, I believe, that gas migrates to the gas cap, and I think that's what your testimony was. I want to be sure I know what you really mean.

Do you mean that it migrates to the gas cap? Are you talking about a vertical migration up and down?

A Yes, that's exactly what I'm talking about.

Q And if that's so, and you have a continuous zone, the gas will be moving up in that zone, right, is what we're talking about, if that's the case and you perforated all those zones, why doesn't the gas/oil just really take off on it?

A The -- the gas simply migrating -- if there is a balance between the rate at which gas will migrate vertically as opposed to the rate at which it migrates horizontally under the pressure gradient established by the well being on production at a particular well flowing pressure. That balance, the well flowing pressure, dictates the particular rate that you have and the balance is such that you do get a higher GOR, a solution GOR; nevertheless, a significant amount of that gas is migrating vertially upward; not all of it but most of it.

Q Okay. That's all I have, Mr. Hueni. Thank you.

A Sure.

MR. STAMETS: Are there any other questions of the witness?

Mr. Kellahin.

MR. KELLAHIN: Thank you.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Hueni, I was -- how do you say your last name --

A Hueni.

Q -- Hueni, I was reviewing over the lunch hour your conclusions that were placed in the front of your exhibit book, and I was interested in conclusion number 3 about the gas/oil ratios.

Identify for me the time frame or the block of information that was utilized in the preparation by you of the gas/oil ratio behavior in the pool. What -- what time frame did you use?

A The plots that we've presented as total production plots were based on production through May.

Our data that we have for June is simply the data that was presented earlier in the case by Mr. Roe, which indicated a GOR of 1586.

Q The gas/oil ratio behavior that you plotted, was that on an individual well basis or did you do it on an average poolwide basis?

A We plotted the total pool and we also plotted the individual wells which was the data we were looking at this morning.

Q And that data is in the exhibit book?

A Yes, it is.

Q And that data stops, then, with May of 1986.

A That is -- that is correct.

Q All right, sir. I was not unable -- I was unable to locate in the summary of conclusions a conclusion about the existence of a dual porosity system. Have I overlooked one?

A That's correct, because our analysis doesn't require the existence of a dual porosity system. That wasn't what we contended. We said, simply, that the pressure transient gas would support that there may be a dual porosity system.

As long as the pressure remains high in the field, we don't really have any -- we don't have -- we won't have the opportunity to see a large matrix contribution because of the high nature of the matrix.

With the data available to date there is probably -- you probably won't be able to see the contribution of the matrix if there is any, and the only way we see it is through the pressure transient gas, which are subjected inasmuch as dual porosity (unclear), the the appearance can also result in a stratified reservoir seen, as well as from several other reasons, as well.

MR. KELLAHIN: Thank you, Mr. Chairman.

MR. STAMETS: Any other questions of the witness?

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Hueni, well, let me -- let me ask you what you told us about Mr. Greer's Appendix III, Figure No. 3-3, in his Exhibit Number One.

Now if I understood what Mr. Greer was telling us when he originally presented this exhibit, was that for a given permeability in a sandstone reservoir, you have a lot more porosity.

A Yes, I agree.

Q So that the higher rates of flow in fractured reservoirs did not necessarily indicate higher reserves under that particular tract.

A Yes. He -- what he did is that he represented the upper line of this yellow area as being relationship of permeability which determines well flow rate to porosity so that if you had a higher permeability you would have a little bit higher porosity and therefore, perhaps, more oil in place. But it wouldn't be a direct relationship of, or proportional relationship such that if you doubled permeability you would double porosity.

My point was simply that his relationship of porosity increasing as the cube root of permeability is simply using the top line, whereas any point within that yellow range represents a possible combination of permeability and porosity and in fact, my other point was that if we assumed a constant width of the fractures and simply a variation in fracture density, that instead of having a line that was -- represented a cube root relationship between porosity and permeability, you would have a line that is much steeper on this graph, similar to the dashed lines, for example, through the constant widths of .001 shown on the 100 fractures and 10 fractures per foot point and that that steeper line would be more closely a one to one relationship, such that if you had more permeability you would have propotionately more porosity.

In other words, permeability and well productivity can be a direct indicator of oil in place.

Q It seems to me that Mr. Greer went ahead, then, and about three pages following that, what is Figure No. 3-5, took this same information to come up with his X, Y, Z lines on there, and then reported that based upon the interference tests -- well, he found data from the interference tests fell right on the lines that he had calculated.

Does this give more weight to his interpretation of his charts in his manner as opposed to the way you'd like to interpret them?

A Well, there's one problem with interference testing and that is when you use the exponential integral of line source solution (sic) in an interference test you assume a homogeneous mediumn and if you have an interference test that connects two wells by a highly conductive fracture, you're really sampling that fracture and you're not sampling the large volume, large volume that is really surrounding. You're not taking into account the pressure support furnished by fractures that are off the main fracture or by any matrix, if there is matrix.

So the calculation of (unclear) from an interference test under the best of circumstances in a homogeneous medium is considered normally to be accurate to about 30 percent.

In a fracture medium it's much less accurate than that.

So I haven't reviewed his interference test data. I've heard only the manner in which he calculated it using the line source solution and that would be my only comment on the interference test information.

Q So you would say that just the fact that the interference test came up where he would predict it would be has no significance in this case.

A I wouldn't ascribe undue significance to it. I guess I personally believe that the -- that there is a higher probability that fractures are of a constant width and distributed in frequency as opposed to being in constant frequency and distributed in varying widths.

Q If this pool is unitized and gas should be reinjected, would you expect significant increases in ultimate recovery?

A No, I would not because the secondary gas cap, formation of a secondary gas cap, does exactly what you're trying to achieve by some sort of gas injection program.

Furthermore, the injection of gas into the reservoir is -- if there is matrix contribution, it will preclude that matrix contribution at the current time because the pressure won't be drawn down in the reservoir as much as it would otherwise.

I think it's also going to be very difficult to inject gas and to effectively displace, displace oil, just because of the (unclear) permeabilities.

In the Puerto Chiquito Unit, which has structure associated with it, gas injection is a very logical and a very reasonable way to operate that particular field but the Gavilan-Mancos Pool, which has minimal structure, does not have the same benefits of structure that would promote lateral displacement that the other field has.

Q Are you saying that the ultimate recovery from this pool is insensitive to the amount of gas which remains in the reservoir?

A In terms of -- in terms of ultimate recovery, in terms of the rate of recovery it could indeed be sensitive to that provided you sweep the oil zone with the downward moving gas, secondary gas cap. Then you displace the oil. Now whether you displace it with a gas cap that's at high pressure or one that's at lower pressure, it doesn't matter in terms of ultimate recovery, but if you allow the pressure to go way down in the reservoir, then your well rates will go down as well and it may take a longer period of time to do that.

But the ultimate recovery, provided you allow gas to move into this gas cap and to form a gas cap and move downward will be the same.

Q If that's the case, I was wondeirng why you were recommending that we lower the gas/oil ratio.

A Well, it would seem to me that if you want to -- if you want to preserve reservoir pressure so that you keep the well productivities high, then the way to do that is to avoid taking excess gas out with each barrel of oil.

Now if the gas is moving to the top of

the formation, then -- and wells are perforated throughout the interval and are fractured throughout the interval, then as the gas, the area of high gas concentration moves down to the producing interval, then the well will naturally be expected to make a larger amount of gas production.

By setting the gas allowable low, it provides the incentive for an operator to try and avoid producing that gas out of the top of the -- out of the top of the section. You'd be taking out only the part that is dissolved in the oil. That would be the incentive.

So whether the field is unitized or not, it provides the incentive for the operator to try and minimize the amount of gas that he takes out along with the oil.

MR. STAMETS: Are there other questions of the witness?

MR. LYON: Can I ask him --

MR. STAMETS: Mr. Lyon.

QUESTIONS BY MR. LYON:

Q Mr. Hueni, you would agree, wouldn't you, that the pressure of the oil entering the wellbore when a well is producing is lower than the reservoir pressure that you'd measure on a shut-in pressure test?

A Yes, that's -- that's true.

Q So that the -- the pressure at the well is less than the formation away from the well, otherwise you wouldn't have flow toward the well.

Now, as I understood your testimony, you're saying that the reason that some of these wells have a lower gas/oil ratio is that the free gas which comes out of solution when the reservoir fluid is below the bubble point, is that the gas is migrating vertically through the fracture system.

Did I understand you correctly?

A Yes, that's correct. My specific evidence of that was the Native Son No. 1 where the gas/oil ratio was less than the solution gas contained at reservoir pressure. It was a value of 184 and the solution gas content of the oil itself at reservoir pressure was higher than that.

Q And what was the gas/oil ratio of that well?

A It was 184 in May of 1986.

Q Now, when the oil has entered the wellbore the avenue of escape into the reservoir is gone, is that not right?

A Yes, that's correct.

Q So that you might expect the gas/oil ratio of the well to be that which would be the solution ratio at the pressure had entered the wellbore, is that right?

A That -- that would be right if -- provided -- it depends on a well to well basis, but that would be right for a well like the Native Son No. 1.

Q In regard to the Horner plot that you have showing the fluid characteristics, what would the bottom hole pressure of that well be to provide a gas/oil ratio of 184 cubic feet per (unclear)?

A According to the fluid property characteristics that we have on here, the bottom hole pressure would have to be a value of on the order of 215 pounds, psi.

Q Do you -- do you -- in your opinion is the pressure actually that low in that well?

A I sincerely doubt that it would be quite that much, no, sir, and where the extra gas is, I couldn't say.

Q I believe that's all I have.

MR. STAMETS: Any other questions?

MR. CARR: I have some more.

A Sure.

RECROSS EXAMINATION

BY MR. CARR:

Q If we look in your exhibit, I guess it's number -- the book, and you go to the section equity calculations, and coming back up from that, the document immediately above that is a log and then on top of that you've got a sheet, the Gavilan-Mancos Pool Maximum Oil Rates for Vertical Gas Segregation.

As we look at this we don't see where pressure comes into this except, perhaps, in terms of viscosity of oil and also KgKo, is that correct?

A That's correct, and that is -- that is why you can recover the same amount in a gas cap expansion reservoir that we can at high pressure versus low pressure. It's dependent simply on the gas being able to move to the top and displace the oil downward.

Q And is it your testimony that no matter what the pressure is, you're still looking at a production rate of 406?

A No, my testimony was that the -- well, at a 1500 psi pressure and the -- and a well that produces 1335 GOR, would be to produce 634 barrels of oil per day, approximately 850 MCF of gas per day.

Q If we take a situation where the pressure in the well is down to like 100 pounds, you're not anticipating production rates anything like you're depicting on this exhibit, is that right?

A I think that's a fair statement.

Q My statement?

A The productivity would go down considerably.

Q In studying this area, I mean have you become aware of why operators perforate particular intervals and not just random throughout the whole 600 section -- 600-foot section?

A I couldn't -- I couldn't speak for all of the operators.

Q And you don't have any idea why, say, they would pick the A zone to perforate instead of just anything?

A I believe there are certain operators out there that believe that it should be perforated through an extensive interval and fraced because the frac puts it in communication and they don't necessarily believe that we should perforate just a limited area.

Q And one last thing. When you were talking with Mr. Stamets a few minutes ago, if I understood you correctly, you were talking about the gas in the reservoir moving downward to the producing interval and generally upward into the gas cap, is that right?

A Not downward in the producing interval. It's moving horizontally through the reservoir. At the same time it has a tendency to want to rise upwards due to gravity segregation.

Q So there is lateral movement toward the well.

A Oh, of course. There has to be lateral movement or you couldn't get a gas/oil ratio in excess of your -- your solution gas/oil ratio, and it's a balance between -- there's a balance between how fast it moves horizontally and how fast it moves vertically.

Q Okay. That's all. Thank you.

MR. KELLAHIN: May I ask one last question?

MR. STAMETS: Mr. Kellahin.

RECROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Hueni, Mr. Lyon asked you a question with regard to the Native Son Well when he was discussing with you just now, I believe, the development of the secondary gas cap, and that was an example that you used to demonstrate the occurrence of that phenomonen?

A It was an example that I believe indicates the fact that gas is segregating (inaudible).

Q Have you studied any other wells or information from other wells that would also demonstrate for you the vertical migrattion of the gas?

A Well, there -- there are other wells, for example, the Homestead Ranch had a GOR that was very low, below the solution GOR, indicating vertical migration of the gas.

There is a very -- if you will recall when I talked about the Gavilan Howard where they had gas escape into the Mancos formation from the Dakota. That gas was never -- hasn't been reproduced since they repaired the communication and put the Gavilan Howard back on production to start off with a low GOR instead of a high GOR, just indicating once again vertical segregation.

The overall field plot of gas/oil ratio predicted versus actual indicates gas segregation and the production log on the Marauder No. 1 also indicates gas segregation, so it's not one (unclear) that we're looking to.

Q Other than those four specific wells are there any others that you've studied that demonstrate the vertical migration of gas?

A The whole field demonstrates it, as a whole; that's what our testimony is.

MR. KELLAHIN: Thank you.

MR. STAMETS: Any other questions of the witness?

He may be excused.

Owen, do you have anything fur

ther at this point?

MR. LOPEZ: No, Mr. Chairman.

REPORTER'S NOTE: The following pages containing conclusions submitted by Mr. Hueni in written form are incorporated in this record at the request of Mr. Lopez.

"CONCLUSION

1. Production data indicates higher gas-oil ratios (GOR) in areas of maximum oil depletion and correlates to areas lying along a common fracture trend.

2. Several upstructure wells have constant or decreasing GOR's which are less than those of downstructure wells and in some case less than the initial dissolved gas-oil ratio. This indicates effective gas segregation is already occurring.

3. Total field gas-oil ratio has not decreased since 1985 in spite of increased field withdrawals indicating the absence of a significant solution gas drive mechanism and the presence of an effective secondary gas cap expansion mechanism.

4. Due to the absence of signficant structural dip, gas segregates to the top of the formation but will not

move laterally across the field.

5. Increased gas saturation at the top of the formation will eventually descend to the level of the perforations causing increased GOR's. This cannot be avoided in the long term. Therefore, high GOR's should not necessarily be attributed to a solution gas drive mechanism without confirmation from production control surveys.

6. Pressures are currently below the bubble point pressure throughout the reservoir volume.

7. Pressures are continuing to decline linearly with oil withdrawals in spite of higher oil production rates.

8. Significant permeability variations exist in the Gavilan Mancos Pool. Higher permeability areas will allow for more rapid gravity segregation of oil and gas.

9. Pressure-production data indicates a reasonable value of original oil in place of 100 million barrels. This could be reduced depending on lab measurements of rock compressibility.

10. Matrix porosity may contribute to ultimate recovery although the magnitude of the current contribution cannot be determined. The contribution of the matrix will be more significant as the pressure is lowered.

11. Comparison of predicted solution gas drive performance to actual data indicates the reservoir is not a so-

lution gas drive reservoir but is behaving as a gas cap expansion reservoir.

12. Gas segregation calculations indicate that current oil zone gas saturation is 1.5 percent while approximately 1,185 million cubic feet of gas have migrated upstructure.

13. Very small increases in gas saturation in the oil zone will result in higher gas-oil ratios in spite of the fact that gravity segregation will continue to occur if rates are restricted below those contained in this report. It is not possible to determine if increased GOR's relfect higher oil zone gas saturation or expansion of the secondary gas cap, without the availability of production control surveys.

14. In order to maintain current gas segregaton in the reservoir, producing rates need to be limited. An oil allowable of 702 BOPD (per 320 acre unit) and gas allowable of 453 Mcfd based on an initial solution gas-oil ratio of 646 scf/STB is more than adequate to maintain effective segregation.

15. Imposition of a 200 BOPD, 1000 scf/STB GOR allowable will distort equity by unduly restricting production from recently drilled wells in the northeast section of the pool.

Recommendation

Based on the analysis presented in this report, the maximum allowable for oil should remain as provided by statewide rules, or 702 barrels of oil per day per 320 acre spacing area. Gas production should be restricted to a volume equal to the maximum oil allowable multiplied by the initial solution gas-oil rato of 646 standard cubic feet per barrel of oil. For a 320 acre spacing unit this would allow for a maximum gas production of 453 thousand cubic feet of gas per day."

MR. STAMETS: Who's next? Mr. Padilla.

MR. PADILLA: Mr. Chairman, first of all, I'd like to make a -- based upon -- a statement based upon your admonition after the lunch hour.

In the interest of brevity we have decided to cut any of the engineering testimony that we have -- we have -- we were going to present that would appear to be cumulative and this is based on the excellent presentation that was made by Mr. Hueni.

And that is the reason Koch Industries, Koch Exploration is here today, so -- however, we do not want to waive the right to surrebuttal should additional engineering testimony be presented that we would want to rebut.

MR. STAMETS: I understand.

MR. PADILLA: So with that in mind, as long as you will allow us to come back and do sur-rebuttal if that be necessary.

MR. STAMETS: If rebuttal comes up we'll be sure that everyone gets equal time or at least in general the two sides, the pros and the cons.

MR. PADILLA: Call Mr. Stan Bennett.

GEORGE STANLEY BENNETT,

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

DIRECT EXAMINATION

BY MR. PADILLA:

Q Mr. Bennett, for the record would you state your name and by whom you're employed?

A My name is George Stanley Bennett. I'm employed by Koch Exploration in Wichita, Kansas, as Chief Engineer.

Q Briefly, Mr. Bennett, can you tell us what the interest of Koch Exploration is in this hearing?

A Yes. Koch Exploration has an interest in the three wells operated by -- a significant working interest in three wells operated by Mallon, Mallon Company.

Those three wells are the Howard Federal 1-11, Howard Federal 1-A, and the Fisher 2-1. These are located in the northeast portion of the field in Sections 1 and 2, 25 North, 2 West.

Q Mr. Bennett, have you previously testified before the Oil Conservation Commission and had your credentials accepted as a matter of record?

A I have not.

Q Will you tell us what your educational background is and where you went to school?

A I received a Bachelor of Science in petroleum and natural gas engineering from the Pennsylvania State University in 1962.

I received a Master of Science in petroleum and natural gas engineering from the Pennsylvania State University in April of 1984.

I was employed by Mobil Oil International starting in October of 1983 (sic).

After approximately a year in a training program in the United States, where I worked in the Rocky Mountain area, I was transferred to New York where I spent about a year in the Planning Department.

Following that, in 1965 I was transferred to Mobil Oil Libya, where I worked as a reservoir engineer from 1965 to 1972.

During that time in Libya I became a Senior Reservoir Engineer and when I left that post I was in charge of Mobil Oil Libya's largest reservoir in Libya. This is a reservoir that has recoverable reserves of approximately 3-5 million barrels of oil.

The reservoir, which consisted of a sandstone reservoir and a fractured (unclear) type reservoir.

Following that I went to work for Gulf Research and Development Corporation in Harmonville, Pennsylvania, that was in 1972, and I remained with them until 1978.

During my service with Gulf Research and Development Corporation I was involved in reservoir studies, numerical reservoir simulation, and the development of the numerical reservoir simulators.

During that time I studied reservoirs in the North Sea, Africa, the Middle East, the Gulf Coast, the Rocky Mountains, Oklahoma, and Texas.

Following -- in addition to that I taught and participated in in-house Gulf Oil schools. My portion of these schools was to teach fluid flow and pressure transient analysis.

Following my employment with Gulf Research, I went to work for Occidental Petroleum from 1978 to 1983, where I was initially employed as a District Engineer responsible for reservoir engineering and economic analysis in the Gulf Coast and Eastern United States for Occidental Petroleum.

I was promoted to operations manager where I became responsible for all the engineering operations in the Gulf Coast and Eastern United States.

Following that period I spent time in private consulting practice from 1983 till 1984.

In late '84 I joined Koch Exploration in my current position.

In my current position I'm responsible -- I'm Chief Engineer, responsible for reservoir engineering and economic analysis and acquisition for the Koch properties in the domestic United States.

Q Mr. Bennett, what activity -- what -- what is it that you do with respect to the Gavilan-Mancos Pool in your capacity at Koch?

A As Chief Engineer with Koch I'm responsible for all the reservoir engineering that is conducted by Koch Exploration, so that any reservoir engineering we do on a project, and I would like to point out that Koch takes a very active interest in anything we generally have a working interest in. We monitor it very closely.

I would be ultimately responsible for the work to be performed at my direction by the various engineers who work for me.

Q Does Koch have an interest in the West Puerto Chiquito or the Canada Ojitos Unit?

A Yes, we do. I think we have about a 3.8 percent net revenue interest in -- well, about 3.8 percent working interest and about a 4 percent net revenue interest.

Q Is that under your area of supervision?

A Yes, it is.

Q Have you made a study in preparation for today's hearing concerning the application of Jerome McHugh?

A Yes. Yes, Koch Exploration has made such a study and I have actually participated in that study.

We have examined data that was provided to us through the Engineering Subcommittee.

We have examined data that's been provided to us through our working interest in Mallon wells and we've gathered other data as necessary (unclear).

MR. PADILLA: Mr. Chairman, we tender Mr. Bennett as an expert petroleum engineer.

MR. STAMETS: Mr. Bennett, my

ears, I don't think worked correctly on some of these dates.

You got your Master's in --

A April, 1964.

MR. STAMETS: '64, and you went to work for Mobil in '63.

A Yes, October of '63.

MR. STAMETS: Okay, I had you 20 years after that and I wasn't too sure about that.

Any questions? The witness is considered qualified.

Q Mr. Bennett, were you present during Mr. Hueni's testimony here today?

A Yes, I was in the room during Mr. Hueni's testimony and did listen to it.

Q You, specifically, did you listen to the conclusions that Mr. Hueni made in his study?

A Yes, I did.

Q Do you agree with the conclusions that Mr. Hueni arrived at?

A Yes, I do, Mr. Padilla, and I'd like to make a little statement here.

Basically the study we did and work we were prepared to present here in testimony today would be cumulative to Mr. Hueni's work.

We basically arrived at the same conclusions Mr. Hueni did and that is basically that we do not feel the Gavilan-Mancos Pool is rate sensitive. We do not feel the reservoir is being damaged by the current allowable as imposed by the State of New Mexico and we really so no reason to propose any additional -- any changes upon that.

Q Do you conclude that there is going to be reservoir damage if the application is not -- will not be approved?

A No, Mr. Padilla, it is our opinion that if the allowable is not granted, if the allowable continues at 702 and 1000 GOR as currently imposed upon the reservoir, damage will not occur to the reservoir.

Q Mr. Bennett, will the ultimate recovery of the reservoir be affected if Mr. Hueni's proposal is adopted?

A Based on our data we do not believe the ultimate recovery of the reservoir will be affected by the adoption of Mr. Hueni's proposal.

MR. PADILLA: Mr. Stamets, we pass the witness.

MR. STAMETS: Are there questions of the witness?

CROSS EXAMINATION

BY MR. CARR:

Q Mr. Bennett, you testified that you agree with Mr. Hueni in the presentation that he made.

A I agree with Mr. Hueni's conclusions.

Q And in getting to those conclusions do you differ with him in the approach that he took?

A I think all engineers have looked at basic data will probably tend to take a different approach and probably the path by which we get to a conclusion isn't as critical as the conclusion to which we arrive at.

Q Now, in getting to that conclusion, for example, do you believe that the actual bubble point that is used in making these calculations is of significance?

A I'm studying that question so I --

Q I understand.

A The difference in terms of pounds per square inch in the order of magnitude of the 1770 Mr. Hueni said his correlations determined was the bubble point and the 1482 which I believe the technical subcommittee has -- has accepted from the Loddy No. 1 (unclear) McHugh, are fairly close in order of magnitude and probably don't make a lot of difference.

You'd catch a little -- you'd probably recover slightly more behind the bubble point because there's more pounds per pressure drop to allow you to recover more oil.

Q In terms of Mr. Hueni's discussion about vertical communication within the Gavilan, do you concur with that?

A I think Mr. Hueni's model that he presented on vertical segregation is reasonable and supported by the facts that he presented.

Q And was that basically what you were going to be testifying to?

A Our testimony was probably not as extensive as Mr. Hueni's.

MR. CARR: I don't have any further questions.

MR. STAMETS: Other questions of the witness?

You may --

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Bennett, relying on your -- in formulating your conclusions and relying on Mr. Hueni's presentation, have you utilized any different information than he utilized in reaching yours?

A Mr. Kellahin, the only information we

utilized was basically that which was presented in the Engineering and Technical subcommittee in the several meetings that they had in Farmington.

Q Did you update any of your gas/oil ratio analysis to include the June and July information?

A We included the June data as was presented by the Engineering Subcommittee in the -- as was provided to the Engineering Subcommittee in the last meeting they had on July 31 and August 1.

Q You used the information that Mr. Roe had in his presentation several weeks ago?

A I haven't checked his data one for one with my well but we used what was provided by the Engineering Subcommittee.

Q Was anything occurring with the gas/oil ratios on any of your wells for the months of June and July that was significantly different from the month of May?

A I don't recall.

MR. KELLAHIN: No further questions.

MR. STAMETS: Any other questions of the witness?

He may be excused.

MR. BENNETT: Thank you, Mr. Chairman.

MR. PADILLA: We'll call Mr. Carl Pomeroy at this time, Mr. Chairman.

CARL F. POMEROY,

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

DIRECT EXAMINATION

BY MR. PADILLA:

Q Mr. Pomeroy, for the record would you please state your name and by whom you're employed?

A My name is Carl F. Pomeroy. I'm employed by Koch Exploration Company as a staff reservor engineer in Wichita, Kansas.

Q Have you previously testified before the Oil Conservation Commission, sir?

A No. No, I have not.

Q Would you state what your educational background is?

A I attended the University of Oklahoma with a full academic scholarship beginning in 1971.

I was graduated with a BS in chemical engineering, with distinction, in 1975, and with a Master's of Science in petroleum engineering in 1979.

Q What is your work experience in the oil and gas business?

A Begining in the summer of '72 and '73 I worked during the summer for oil companies. Those two summers I worked in gas plants near Hobbs, New Mexico, for Warren Petroleum Company.

I worked as an engineer's assistant for Texaco in Kingfisher, Oklahoma, during the summer of '74.

I went to work for Cities Services Oil Company in 1975 as an engineer in Oklahome City.

I spent one year as a production engineer, four years as a reservoir engineer, and one year as a drilling engineer.

In 1981 I then went to work for the Plains Resources as a production manager in Oklahoma City.

In 1982 I went to work for Koch Exploration as a Senior Reservoir Engineer in Wichita, Kansas. My duties for Koch have included being responsible for Koch's reservoir engineering for the San Juan Basin for the last four years.

Q In the San Juan Basin, the work that you do, are you in charge of the Gavilan-Mancos Pool?

A Yes, I am.

Q How about the West Puerto Chiquito Unit?

A Yes.

Q Have you authored any papers, Mr. Pomeroy?

A Yes, I have.

Q What are those?

A I co-authored a report on Bio-mass Conversion for the Electric Power Research Institute, which was published in 1979 or 1980.

I also co-authored a book on Bio-mass Conversion Processes, which was published by Plenum Publishing Company. I think the year it was published was 1981.

Q Have you taught school anywhere in connection with your education and experience?

A Yes, I've taught some engineering classes at the University of Oklahoma.

I taught classes in thermodynamics and reservoir engineering.

Q When was that?

A That was approximately '77 and '78 that I taught the thermodynamics and I taught the reservoir engineering in -- let's see, my last year with Cities Service was '81 and then in '82.

Q Have you participated in the Engineering Subcommittee (inaudible)?

A Yes, I have.

MR. PADILLA: Mr. Chairman, we tender Mr. Pomeroy as a petroleum engineer.

MR. STAMETS: If there are no questions, the witness is considered qualified.

Q Mr. Pomeroy, have you prepared certain exhibits for introduction today?

A Yes, I have.

Q Let's go first to what we have marked as Exhibit Number One and have you identify that for the Commission.

A I went ahead and put the first three exhibits on the wall and we will distribute small copies of that large map.

Q Go ahead, Mr. Pomeroy, and tell us what that is.

A This is a bottom hole pressure map of the Gavilan area.

We have posted the reservoir pressures, or the bottom hole pressures directly to the common datum using the reservoir study from the Gavilan study committee, and these pressures are corrected to June 1st to make them all on a common time element.

The way that the data was corrected to a common time element was if we had a pressure before June 1 and one after June 1, we just interpolated the (unclear) between those two dates and the two pressures that we would have and if we did not have one on each side of June 1st, then we just took the -- an average pressure drop in terms of psi per days to extrapolate the pressure to the June 1st date.

Q I notice that you have different shades of coloring on that. Can you explain for the Commission what the --what significance that shading has?

A The first shaded area, which is the largest, includes everything that has a pressure of less than 1500 psi.

The next contour is 1400 psi and it's in kind of a purple color, and then the deeper red is everything with a reservoir pressure, bottom hole pressure of less than 1300 psi.

Q What particular sections are you pointing at when you show the deepest red there?

A Basically I'm talking about Sections 2 and 11 in 24 North and 2 West.

Q And then you have an extension of that area to a lighter shade, is that correct?

A Yes, that is correct.

Q Is that lower pressure or higher pressure?

A The extension to the different colors is from the low pressure in the two sections, Section 2 and 11, into higher pressures.

Q Now, why have you segregated one oval up at the top of that exhibit or the north of the main area?

A The reason that this area to the north, which basically includes the north half of Section 12 and part of the south half of Section 1, is that there is a well in Section 13 in between the two areas that has a high pressure. In this case the well in section -- in the north half of Section 13 has a pressure of 1568, which is quite a bit higher than the 1500 pounds that is contoured.

Q What does that -- what is the significance of the well in between the two areas? What does that tell us?

A This tells us that the pressure, the area with a pressure of less than 1500 pounds to the north is separated by a pressure that is higher in the area to the south, indicating there likely will not be any drainage occurring in the area in between, at least not as significant as the areas with the lower pressures.

Q Do you have anything further concerning Exhibit Number One?

A I would like to point out at this time that the well with the lowest pressure is the New Horizon No. 1 in the south half of Section 2. It shows a pressure of 1203 pounds.

Normally you would expect a well with the lowest pressure to be a well with one of the highest withdrawals in the area. We will show in the other maps, that's not true in this particular instance.

Q Let's go on to Exhibit Number Two, Mr. Pomeroy.

A Exhibit Number Two is a map showing the cumulative oil production for the wells in the Gavilan area. This is overlaid on a base of the structure map that Mallon-Mesa Grande put together, mainly just for convenience.

This shows three separate areas colored in green with pressures -- I mean with cumulative production of more than 100,000 barrels per well.

We've got one area covering one well in the south half of Section 29. We've got one area covering one well in the south half of Section 24. And then we have a much larger area more or less in the middle of the main area of production centering around Section 27 and including a large part of Section 34.

Q Let me -- let me get this straight in my own mind. What does the darker green mean?

A The darker green represents the area with cumulative production of greater than 300,000 barrels.

Q That's the greatest cumulative production.

A That's correct. That's the greatest cumulative production shown on the map. There's one well that fits that category, and that is the J. P. McHugh Native Son No. 2.

The next darkest area of green is an area shown for wells with production of greater than 200,000 barrels per well and that's basically just surrounds the one well that -- 300,000 production.

Then we have a much larger area with -- covering the wells with production greater than 100,000 barrels per well.

Q Okay, do you have anything further to -- concerning Exhibit Number Two?

A I would like to point out that the New Horizon No. 2, which is shown as the lowest pressure on the pressure map, which is the south half of Section 2, shows very low production. There are no wells in this immediate area that have the significant production that Section 27 has.

Q Mr. Pomeroy, let me hand you this marker and have you circle that well on both of those exhibits.

A Okay, on Exhibit Number One I'm circling the New Horizon No. 1 and now in Exhibit Number Two I'm circling the New Horizon No. 1.

Q Would you repeat for me again what the significance of the two exhibits is, as far as that New Hor izon Well is concerned?

A Again, normally you would expect the area of the reservoir with the lowest pressure to be the area of the reservoir with the highest withdrawals and that is not the case for the New Horizon No. 1.

Q How does that compare with Mr. Roe's testimony?

A If you expected the pool to be connected and have tremendous transmissibility throughout, I would expect for the pressures to be more uniform than they are and I would also expect, especially in the well with the lowest pressure, that there should have been more production from that area.

Q Does that show that there is a lack of communication between wells?

A It indicates that there is not a real high degree of horizontal transmissibility.

Q Okay. Do you want to move on to Exhibit Number Three at this time?

A Yes, I would. Exhibit Number Three is a map showing the cumulative gas production. We have several areas colored.

The first colored area represents wells that have produced in excess of 100,000 -- excuse me, 100-million cubic feet of gas.

The next different shade shows the wells that have produced in excess of 300-million cubic feet of gas and then the deepest red shows the wells that have produced in excess of 400-million cubic feet of gas.

Q Are you going to compare all three maps at this point? Is that your intent, Mr. Pomeroy?

A Yes, it is.

Q Okay.

A Again with a green marker I'll mark the New Horizon No. 1 in the south half of Section 2, 24 North, and again it is not in the area of the high gas withdrawals.

This shows that it is not either in an area of high oil withdrawals or in an area of high gas withdrawals.

It represents that pressure is extremely unusual for what you'd expect in a nice, homogeneous reservoir.

Q How does that compare -- well, what significance does this have, do all three exhibits have with respect to the application, Mr. Pomeroy?

A I believe that these three exhibits, in particular the New Horizon No. 1, supports the conclusion that there is not an excessive amount of horizontal transmissibility and supports the case that allowables do not need to be reduced (not clearly understood.)

Q Is that all you have concerning those three exhibits, Mr. Pomeroy?

A Yes.

Q Okay, you may resume your seat.

Mr. Pomeroy, I'll have you refer to what we have marked as Koch Exhibit Number Four and have you tell us what that is.

A Koch Exhibit Number Four is the effect of the allowable production on pool oil production and reservoir withdrawals. This assumes an allowable of 702 barrels per day witha limiting GOR of 588 cubic feet per barrel.

This is the exhibit or the information that we passed out last time in response to a request by the Commission.

Q Okay, would you go on and tell us about this exhibit? What does it tell us?

A Okay, this exhibit summarizes by operator in the top half the oil production by operator. It shows what the actual April '86 production was as reported by the Engineering Technical Subcommittee.

The next column shows the June '86 production, again as reported by the Technical Subcommittee in the last meeting.

The next column shows the percent increase for each operator between June and April.

The next column, marked proposed oil, shows what the effect would have been in June if the 702 and 500 cubic feet per barrel allowable would have been in effect.

The next column shows the percent increase for June if the allowable had been in effect at 702 and 588, as compared to the April production for each operator.

This shows that the Gavilan Pool area, which produced 5706 barrels of oil in June would have produced 4923 barrels of oil per day under an allowable of 702 barrels per day and 588 cubic feet per barrel.

The bottom half of the exhibit shows the production in reservoir barrels by the operators, showing the same columns for April, June, an increase from June to April, what the effect on 702 and 588 allowable would have been on the reservoir production, and the increase that that would have caused from April of '86.

This shows that under this case the reservoir barrel withdrawals in the Gavilan Pool area would have gone from 16,437 barrels per day in June to 13,120 reservoir barrels per day had the allowable of 702 and 588 been in effect.

One thing I'd like to add here is the wells in the Canada Ojitos Unit are shown for the rows marked BMG and these are the wells within the study area as outlined by the Technical Subcommittee.

If you divide the reservoir barrel withdrawals under the 702 and 588 for June by the June production in reservoir barrels per day, it shows a 20 percent decrease in the reservoir withdrawals.

Q Looking at the last column on that exhibit, Mr. Pomeroy, tell us about the increase and decrease on the individual operators and how it affects the operators.

A Okay. What this percent increase again is the -- it shows the increase over April. Amoco, according to the production presented to the Technical Subcommittee had no production in April or June so there is no change.

Dugan had a relatively small amount of production in April, only 45 reservoir barrels per day, and so they show a large increased for the actual June and then for the proposed reduction in June.

I'd like to point out at this point that the reason the column in reservoir barrels for Dugan does not exactly coincide for the 269 and the 272 is because there was a very slight round off effect program used to calculate these.

That's the only case where this problem

showed up.

Mallon shows a 14 percent decrease over April production in reservoir barrels. It turns out to be a higher reduction in barrels of oil, a 32 percent reduction from the April oil levels, and I'd like to point out at this time that the wells that Koch has an interest in are three of the Mallon wells.

Meridian has a relatively smaller reduction in reservoir barrels, about 10 percent from April figures, and essentially no change from the actual June to what the June would have been under this allowable case.

Mesa Grande has about a 28 percent reduction from the April and McHugh has an actual increase because the June production was actually higher than the April production.

Q Mr. Pomeroy, looking at the Mallon figures, in your opinion does that violate correlative rights in those wells inasmuch as those wells are much (unclear) wells?

A Yes, I think they are unduly penalized under this case.

Q Do you have anything further concerning Exhibit Number Four?

A Not at this time.

Q Okay, let's go to Exhibit Number Five.

A Exhibit Number Five is the same calculations using the applicant's proposal of 200 barrels of oil per day and 1000 cubic feet per barrel of oil limiting GOR.

As we go through the percent increase column in this case, this shows that the Mallon wells are hit even harder under this case and would result in substantially more production curtailment.

The Mallon wells would suffer a 62 percent reduction in oil as compared with April levels and I don't have the numbers calculated, it would be about the same, based on the actual June production.

Reservoir barrels for Mallon would decrease by 53-1/2 percent from April '86 to what it would have been in June had the applicant's proposal been in effect.

Q Is that all you have concerning Exhibit Number Five?

A Yes. I'd like to talk a little bit about a couple of other exhibits presented by other companies at this time.

Q Okay, what are those exhibits, Mr. Pomeroy?

A Those are Dugan's Exhibit Number One and Meridian's Exhibit Number One.

MR. STAMETS: Okay, we're with

you.

A Okay. Everybody ready?

Okay, turning to page four of Dugan's Exhibit Number One, the total reservoir barrels per day withdrawal from the Gavilan Pool in June, according to Mr. Roe's calculations, was 25,993 reservoir barrels per day and the effect of the applicant's proposal would result in a total pooled area production of 14,143 reservoir barrels per day.

These numbers are both higher than the numbers that I showed on Koch's Exhibit Number Five and the basic reason for that is Mr. Roe included production estimates for certain wells that were not on production in June or that he felt did not produce at their indicated capacity.

I attempted to use only the wells that were produced during June and used the production that was available at the last Technical Subcommittee in Farmington.

Mr. Roe's exhibit shows a 46 percent reduction in reservoir barrels for the applicant's proposal, based on June production data.

My Exhibit Number Five shows a reservoir production from June to what the actual (unclear) if the applicant's proposal had been in effect of a bout 46-47 percent. The percentage is not shown but if you go through the calculations you come up with essentially the same percentage that Mr. Roe showed in his exhibit.

This shows that the two types of calculations are compatible and are in close agreement with just a little different phase in the production that was used because of the estimated figures that Mr. Roe included.

So we essentially both agree as to what the effect would be in terms of percentages.

I'd like to go now to Meridian's Exhibit Number One, page number one.

This exhibit showed that Meridian has a decrease of 1248 reservoir barrels per day to 834 reservoir barrels per day based on the applicant's proposal. This results in a reduction of 33 percent.

The exhibit further shows that the total Gavilan Pool withdrawals would decrease from 17,163 to 13,954, for a reduction of 3,211. This represents a reduction of only about 19 percent.

This does not correspond to the calculations made by Koch or by Dugan. I think that there may be a slight error in Meridian's calculations here.

The 19 percent reduction in reservoir barrels per day withdrawal corresponds very closely to the percentage reduction that Koch has calculated for 702 barrels per day allowable with a limiting GOR of 588 cubic feet per barrel.

Q Mr. Pomeroy, does that mean that Meridian's figures would decrease as far as their share of production is concerned?

A The decrease in Meridian's production, according to my calculations on Exhibit Number Five, show a reduction of 47 percent from April and a lesser amount from June, which is approximately a 33 percent range, so I think that the Meridian calculations for the effect on Meridian are correct. They are in the order of 33 percent; however, the Meridian calculations for the effect on the total pool are incorrect and that Koch's calculations of 46 to 47 percent reduction in reservoir barrels per day is correct, and this conclusion is supported by the data presented by Dugan.

Q Do that means Meridian doesn't get hurt as bad, is that -- is that --

A That is correct. Meridian does not get hurt as bad as the average.

Q Let me ask you about on Exhibits Four and Five with respect to the McHugh interest, would -- how is the McHugh interest affected by your calculations?

A Okay, starting with Exhibit Number Four, McHugh drops from 2800 barrels per day of oil production to approximately 2500 barrels per day oil production, assuming a limiting GOR of 588 cubic feet per barrel and an oil allowable for 702 barrels per day.

I don't have the calculations in front of me but that's a reduction of 300, approximately 300 barrels of oil per day, which is slightly more than 10 percent.

Q In terms of relative reductions, is McHugh hurt or helped by the proposal in comparison to the Mallon production?

A McHugh is hurt to a much lesser extent than Mallon is.

Q Why is that?

A Mallon's production under this proposal of 702 and 588 has a decrease in oil production from 1619 barrels per day to 1157 barrels per day, which is approximately 450 barrels per day or about a somewhere between 20 and 30 percent reduction, which is significantly more than the 10 percent or so suffered by McHugh.

Q Mr. Pomeroy, does this indicate that possibly McHugh might receive a disproportionate and larger share of the reservoir energy while this proposal is in place?

A Yes, I think that's correct.

Q Assuming a homogeneous reservoir, would -- as McHugh has testified here, would --

MR. KELLAHIN: I'm going to object, Mr. Chairman. I don't believe any of our witnesses have characterized this as a homogeneous reservoir.

It's a misstatement of the evidence.

MR. PADILLA: Mr. Stamets, I believe the testimony has been that there is uniform pressure throughout the -- throughout the Gavilan-Mancos Pool, and in addition to that the pressures, as far as Mr. Roe's testimony is concerned, is that there is communication from the Mallon wells all the way down to the southern end of the pools.

MR. STAMETS: I believe what -- what they stated was that there was pervasive communication as opposed to homogeneity.

MR. PADILLA: I'm not sure that I understand the difference but --

MR. KELLAHIN: I've got some people that would be happy to tell you, Mr. Padilla.

MR. STAMETS: So where does that put us on this question if we -- if we agree that they did not use --

MR. PADILLA: Let me rephrase the question on the basis of pervasive communication, then, Mr. Stamets.

Q Mr. Pomeroy, assuming pervasive communication as the McHugh witnesses have testified to, would there be drainage to the McHugh wells under this proposal under the application?

A Assuming the pervasive communication to be throughout the pool, I think we would have to consider what the effect on the pressure immediately around the wells would be and the reservoir fluids would tend to migrate toward the areas of lower pressure.

Q Mr. Pomeroy, would you please refer to what we have marked as Koch Exhibit Number Six and have you tell us what that is.

A Koch Exhibit Number Six is a graph showing the projected formation pressure over time based on the June, 1986, production, assuming a production rate for June of an average of 5706 barrels of oil per day and also assuming a production pressure coefficient of 5000 barrels of oil per day per -- actually that should be 5000 barrels of oil per psi.

MR. STAMETS: Take the -- take the "d" off of that?

A Yes.

Q Where is that, Mr. Pomeroy?

A In the little bracket to the upper left-hand portion of the exhibit. The production/pressure coefficient has units of barrels of oil produced per pounds of reservoir pressure drop, so it should be just barrels of oil produced per psi.

Q In other words, that would be BOP/psi, is that --

A That's correct.

Q Okay, tell us what the yellow is in this exhibit.

A The yellow colored in this exhibit represents the remaining reservoir energy, or reservoir pressure under the current allowable situation for various points in time beginning in September, 1986, and ending in April, 1987.

Q Okay, tell us about the first straight line that you draw across there from the bottom, going from the bottom to the top, what is that line?

You've labeled it "current allowable". Tell us what that is.

A Okay, that line is based on producing the 5706 barrels of oil per day and using the production pressure coefficient of 5000 barrels oil produced per psi pressure drop, then calculating the pressure drop over time with those two assumptions. That is the first line from the bottom that divides the yellow shaded area from the area shaded in the two blue colors.

The next line is labeled "702 barrels per day, 588 GOR allowable". This shows the effect on reservoir pressure, assuming the allowable as stated, 702 and 588.

The difference between the reservoir

pressure at any given point in time between the -- what the pressure would be under this allowable and what it would be under the current allowable is shaded in the dark blue.

The next line represents what the pressure over time would be for an allowable of 200 barrels per day with a limiting GOR of 1000 cubic feet per barrel.

The difference between the 200 and 1000 allowable case and the 702/588 allowable case is shaded in the light blue.

Q What is that difference? What does that compute to in relative terms, say during the period in the application? Can that be (not understood) on this graph?

A Yes, it can. If we go to the 90 day period, if we assume for the purposes of this graph that it started in September, actually we could change the months here, a quarter doesn't go into effect in September. We'll just start a little bit lower on the graph. The difference per month would be the same.

Going three months over to December, I show a difference between the applicant's proposal and the current allowable of 43 psi.

Q Mr. Pomeroy, what does 43 psi mean in the pool life of this, a pressure reduction of 43 psi?

Is that normal in your opinion?

A Yes, I think it is normal. I think it is not anything to be concerned about.

Q Does it constitute an emergency to have a reduction of 43 psi over this period?

A No, it does not.

Q What else do you have to testify concerning Exhibit Number Six?

A I'd like to point out that under the applicant's proposals, a pressure drop in three months would be in the order of 60 psi.

Under the case of 702 barrels per day and 588 GOR, the pressure drop would be 89 psi, and under the current allowable it would be 103 psi.

So the option of 702 barrels per day with 588 GOR allows the opportunity to slow down the reduction in reservoir pressure without having te extreme effect that the applicant's proposal would have.

Q Okay, let's go on to Exhibit Number Seven, Mr. Pomeroy, and tell us what that is.

A Exhibit Number Seven shows the production consequences of the proposed allowable reduction for a three month period based on June, 1986 production.

My calculations on a barrel per day basis multiplied times the number of days in three months show that the current allowable would allow oil production of 513,540 barrels of oil over a three month period.

The applicant's proposal would reduce the production from the pool to 301,770 barrels of oil for an immediate loss over a three month period of 211,770 barrels of oil production.

The next line shows the effect on gas production. The current allowable would have a production of 738,990 MCF. The applicant's proposal would have 386,640 MCF, for an immediate loss of 352,350 MCF production over the three month period.

I'd like to point out that the column entitled "Immediate Loss" is shaded in red to highlight the effect of the loss.

Q Mr. Pomeroy, in your opinion is this immediate loss necessary?

A No, it is not necessary.

Q Would you elaborate on that for the Commission, please?

A As Mr. Bennett has stated, the work that Koch has done has concluded that reducing the allowables will have no effect on the ultimate recovery from the Gavilan Pool and therefore there is no reason to reduce the allowables to have this substantial amount of production lost during the three month period.

Q Is that all you have on Exhibit Number Seven, Mr. Pomeroy?

A Yes, it is.

Q Let's go on to Exhibit Number Eight and have you tell the Commission what that is.

A Exhibit Number Eight shows the revenue consequences of the proposed allowable reduction for the same three month period based on the June, '86 production.

The assumptions used in this revenue calculation are listed on the bottom of the exhibit.

These assumptions are an average royalty of 1/8th; an oil price of $15.00 per barrel; and a gas price of $1.25 per MCF.

The production used to make these calculations are the same production figures shown in Exhibit Number Seven.

This shows that the immediate loss of the three month period for the State of New Mexico production taxes would be $317,341.

Working interest would have a revenue loss of $2,887,192 and the royalty interest would lose $412,455, for a total revenue loss over the three month period to all these parties of some $3,616,838.

Q And we go on to Exhibit Number Nine, now, Mr. Pomeroy? Are you through with Exhibit Number Eight?

A Yes, that's all I have on Exhibit Number Eight.

Q Exhibit Number Nine shows the economic costs of repressurization for the production from a three month period based on the June '86 production.

The assumptions used in these calculations again are a gas price of $1.25 per MCF; injection costs of $0.25 per MCF; gas formation volume factor of 1.78 reservoir barrels per MCF.

The purpose of this exhibit is to show what the economic effect would be if the operators in the Gavilan Pool decide that pressure maintenance is necessary and that the pressure should be increased to the level it is before the proposed order is put into effect, assuming that the order is in effect for three months.

This calculates the amount of gas required based on the reservoir voidage over that period of time and assuming that additional gas is purchased and injected to make up the reservoir voidage that is produced during the three month time period.

Under the current allowable reservoir voidage for three months is 1,479,330 reservoir barrels.

Applicant's proposal would reduce that 785,610 reservoir barrels for a reduction of 693,720 reservoir barrels.

The volumes of gas required to replace those reservoir barrels of voidage are shown on the next row. The reduction for the applicant's proposal is 389,700 MCF. The cost of the gas that would be required to get the pressure back up under the current allowable would be a $1,246,590.

Under the applicant's proposal it would be $662,040 for a reduction of $584,550.

This shows that assuming the operators do decide to put in a pressure maintenance (unclear), the incremental cost to get the pressure back up would only be the cost of buying and injecting the gas required to make up the reservoir voidage.

Assuming this was done, the applicant's proposal would reduce the voidage enough to save only $584,000.

The previous exhibit shows that the loss to the State of New Mexico, the operators, and the royalty interest owners would be some seven times that amount.

Q Why is that, Mr. Pomeroy?

A The reason for that is that the value of a reservoir barrel of oil is substantially higher than the economic value of a reservoir barrel of gas, so it is much cheaper to replace the reservoir voidage with gas than it is to prevent the reservoir voidage by reducing the oil productions.

Q Let me see if I understand Exhibit Number

Nine in a nutshell.

Does that mean that this is going to increase the cost of development in the pool?

A Well, actually the additional cost here would only be if the operators decide to bring the pressure back up to the level before the three month period of production went into effect, and it doesn't represent a total loss in dollars because the gas would still be in -- would be put into the ground and would be left there until the reservoir is blown down and produced.

So in effect we would only be bringing the gas for the period of time that the pressure maintenance project was in effect.

Q You wouldn't have the use of the money in the meantime, though, would you?

A That's -- that's correct.

Q Is that all we have on Exhibit Number Nine, then?

A Yes, it is.

Q Okay, let's go on to Number Ten. Would that be your conclusion?

Let me hand you what I have marked as Exhibit Number Ten and have you tell us what that is.

A Exhibit Number Ten is a summary of positions for Koch Exploration Company in this case.

MR. PADILLA: Mr. Chairman, we would request that this summary be included as part of the record and I just simply want to have Mr. Pomeroy briefly tell us what these conclusions are.

MR. CARR: Mr. Stamets, do you think that we could have a copy of that so that we would know if we'd want to object to it or not?

MR. STAMETS: Yeah, I think so.

MR PEARCE: I'd like a copy, too.

MR. POMEROY: We have more copies of it.

MR. PADILLA: Mr. Chairman, it's a short statement. Let me have Mr. Pomeroy read it into the record and that will suffice.

MR. STAMETS: If we're going to have it in the record, let the Commission just take a few minutes to read it and that will, I think, go a lot quicker.

MR. PADILLA: Okay.

MR. STAMETS: The record will reflect the statement that has been -- Summary of Position.

REPORTER'S NOTE: As directed the Summary of Position is hereby incorporated in full in the record.

"Case No. 8946. Koch Exploration Company Summary of Position.

Koch is a major owner of the production which the applpciation here seeks to restrict. As a major owner, Koch is as interested as anyone in assuring the greatest ultimate oil recovery from the Gavilan Pool. That is why we have participated in the owner's study which has been mentioned and why we have conducted our own independent studies.

We conclude the ultimate recovery from the Gavilan Pool will not be enhanced by further limiting oil production. Whether the reservoir drive mechanism is a secondary gas cap, as Mallon-Mesa Grande concludes, or merely a solution gas, the Commission's current regulations will allow maximum recovery, at least through March, 1987, without damaging the Gavilan Pool.

Conversely, the proposed production cut will drastically cut income of owners like Koch and income of royalty owners. The State of New Mexico will lose significant tax revenue. All are already suffering from perhaps the worst depression the oil industry has ever seen.

All that hardship is to no purpose because Gavilan will not benefit from the energy saved. Even if all the studies are completely wrong, and the reservoir would benefit from higher pressure, the drastic cut proposed would save only a meaningless few pounds of pressure.

In any event, even if a few pounds should be saved, the application would cut oil production, when free gas production is the culprit. If the Commission chooses to further limit production, the rational way to conserve reservoir energy is to conserve free gas. Therefore, we have proposed alternatively that gas production should be limited to the solution gas ratio of 588 SCF per STB with oil production still restricted by the existing depth bracket allowable to 702 BOPD."

Q Mr. Pomeroy, a couple of final questions.
You heard Mr. Hueni's conclusions, have you not?
A Yes, I have.
Q On GOR? Do you agree with those conclusions?
A He concluded that the GOR was, I believe, 646 cubic feet per barrel. I think that is a strong possibility that that may have been the solution gas/oil ratio at the time that the reservoir was first developed.
I have no problem with that being the -- a logical conclusion.
Q How does that compare with your 588 fig-

ure in this Exhibit Number Ten?

A The 588 figure shows a reservoir withdrawal reduction as shown in the Exhibit Number Four.

If a solution GOR of 646 cubic feet per barrel were used instead, the effect on the reservoir withdrawals and the oil productiond would at most be a ratio of the 646 divided by the 588. That would be the case if all the wells were limited by the amount of gas production.

So I would estimate that the actual affect would be much less than that; probably on the order of some five or ten percent difference in reservoir production either in terms of barrels of oil per day or reservoir barrels per day.

Q Could you live with that kind of variation or is that -- let me ask the question, is there a material difference between the two figures?

A No, I don't think there is a material difference between the two figures.

Q So you're generally in concurrence with the figures proposed by Mr. Hueni?

A Yes.

MR. PADILLA: I don't believe I have anything else, Mr. Chairman.

Pass the witness.

Oh, let me introduce Exhibits

One through Ten, if I may.

MR. STAMETS: Exhibits One through Ten will be admitted.

Let me just talk about where we are.

(Thereupon a recess was taken.)

MR. STAMETS: The hearing will come to order.

MR. PEARCE: Thank you, Mr. Chairman.

In the interest of time before I begin with this witness let me just say a couple of brief sentences, if I may.

Mobil believes that we have the rest of the story, as they say on the radio. There's a lot of agreement in this pool about that and Mobil does not disagree that GOR's are rising and pressures are declining. We certainly disagree about what that means.

Our evidence will show that although pressures are declining and GOR's are rising that that's normal and it's no kind of emergency at all; that the matrix in this reservoir contains significant amounts of oil which can be produced under the right conditions and that in order to produce that oil more efficiently, more quickly, you need to lower the pressure in that reservoir, not slow that pressure decline.

We're going to show that there is a valid and reliable correlation between log and core porosity and permeability data; that that can be worked if it is worked correctly; and we're going to try to show you that the possibility of gravity drainage is minimal, that in order to try to increase that minimal factor, if you give up significant matrix contribution you hurt the interests of all the operators in this pool; that that damages correlative rights; that in at least time that causes waste and it is unwise.

That's a nutshell version. If I may, I would like at this time to call Mr. John Paulhaber to the witness stand.

JOHN J. PAULHABER,

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

DIRECT EXAMINATION

BY MR. PEARCE:

Q And please, sir, would you state your full name and occupation?

A My name is John J. Paulhaber. I'm a Senior Production Geologist for Mobil Producing Texas and New Mexico, Incorporated.

Q Mr. Paulhaber, would you please give the Commission information with regard to your educational and work experience?

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

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

In 1975 I was employed as a summer student for Mobil Oil in Denver.

From 1977 to 1980 I was employed with Exxon as a geologist.

From 1980 to present I've been employed with Mobil as a geologist.

Q Mr. Paulhaber, during your time with Mobil have your work responsibilities concerned areas of New Mexico?

A Yes, sir. I am currently responsible for the production geology in the northern half of New Mexico.

MR. PEARCE: Mr. Chairman, are the witness' (sic) acceptable as an expert in the field of petroleum geology?

MR. STAMETS: Yes.

Q Mr. Paulhaber, I would ask you at this time to please describe what has been marked as Mobil's Exhibit Number One and indicate the points of significance to the Commission that you believe they should focus upon.

A Okay. This is a 1-to-2000 scale map of the Gavilan-Mancos Pool area.

On this map I have indicated pool boundaries, Gavilan-Mancos Pool being in the center; North Puerto Chiquito Gallup-Dakota Pool being up here; Ojito Gallup-Dakota Pool; West Lindrith Gallup-Dakota Pool; the Lindrith Gallup and Lindrith Dakota Pools down here; and the West Puerto Chiquito Mancos Pool over here.

This map also shows a structure map on the top of what Mobil terms the Gallup interval. This corresponds approximately to what other operators term the Niobrara A.

The contours on 50 foot intervals. The major contours, the heavy lines, are on 250 foot intervals.

The data points I used in drawing these contours are posted below the appropriate well.

Okay. The wells of significant, at least for my testimony and for Luis Zambrano's testimony, are the three Lindrith wells down here to the southeast of the Gavilan-Mancos Pool.

Q Would you indicate for the record, please, sir, the names of those wells?

A Okay. This well in Section 32, 25 North, 2 West, is the Lindrith B-34.

In Section 4 of T24 North, 2 West, we have the Lindrith B-37 in the northeast quarter and the Lindrith B-38 in the southwest quarter. The Lindrith B-38 is the well in which Mobil cored a 183-foot section.

In terms of other items of significance on this map is simply the general form of the structure.

In the Gavilan-Mancos Pool area we see a broad domal feature plunging to the north/northwest, a high in this area, a shallow trough coming to the southwest, and the dips increasing again further to the southwest.

Dips coming off this high into this trough are on the order of, say, 20 to 30 feet per mile. The steepest dips we see out here on an average are on the order of 100 feet per mile coming out principally to the west/northwest.

As we go to the east the structure dips into a slight trough. It starts out gently, we're looking at 200 feet per mile in this region of the map, and the dip increases so that in this approximate area we're looking at about 500 feet per mile.

Q And with regard to the area which you described as having a dip of generally 200 feet to a mile, you are referring to the westerly portion of the West Puerto Chiquito Mancos Pool?

A Yes, this area in here.

Q And the more severe dip is the easterly portion of that pool, is that correct?

A That's correct.

Q Thank you. Go ahead.

A Okay. That's about all I have on this.

Q Thank you. If you'd take your seat again, please, and address for us what we've marked as Mobil Exhibit Number Two at this time and detail for the Commission the significant items of data on that exhibit.

A Okay. We'll put it down here.

Okay, this is what people commonly call an electric log for the Gavilan-Mancos Pool interval within the Lindrith B-38. More specifically the curves we have on here going left to right are the gamma, SP, which is spontaneous potential, the deep induction curve, the sperically focused log curve, the tension curve, and then the conductivity curve from the deep induction log.

I've annotated on this log the top of the Gavilan-Mancos Pool as I have correlated it to the type log for the pool.

Going down the log I've annotated the top of what we're calling the Gallup interval and the base of that interval. I've also defined three zones, A, B, and C, as Mobil sees them and as I believe other operators see them in the pool.

I've also indicated on here the cored interval and also the interval that was actually analyzed of that core.

And the principal purpose of this exhibit is simply to help people orient themselves to the core and to the stratigraphy in the core.

Q All right, Mr. Paulhaber, let's turn now, please, to Exhibit Number Three. Once again if you will describe that exhibit for the Commission and point out items of significance.

A Okay, this is a report provided to us by CORE Laboratories, Incorporated. This report was prepared by their Farmington Office. CORE Laboratories is based in Dallas, Texas, as it indicates on the header.

This is a tabulation of the conventional analytical data taken on 81 plugs that were drilled from the core in horizontal direction on approximately one foot intervals in the sandy portion of the core, and all of these were performed by standard industry-accepted techniques by

CORE Laboratories.

Two items of note on this exhibit, one in the far right column under the description, you'll notice that Sample 4 on the first page, and also other samples on subsequent pages, are marked by a double asterisk in the far right.

This double asterisk indicates that CORE Laboratories that the permeability which was measured in these samples was from fractured rather than from matrix and we just need to keep that in mind in subsequent discussions.

Another item of importance is that the porosity was determined by Boyle's Law, helium porosity method. This is the currently industry accepted standard for determining porosity.

In this measurement helium is allowed to flow into the sample under low pressure; therefore porosity that is measured is interconnected and it is therefore effective porosity.

That's all I have for this exhibit.

Q All right, sir. Next exhibit, if you would, please.

A Exhibit Four is a tabulation of the core data in Exhibit Three. It is provided -- it was provided by CORE Laboratories in their conventional format, which they term a correlation coregraph.

I have added some annotation to this exhibit in order to explain our points.

First let me go through the CORE Lab's portion.

In the lefthand track we see whole core gamma ray. This is used to assist in correlation purposes with the electric logs.

The next track over is the permeability track, scaled 10 millidarcies on the left, 1/100th millidarcy on the right, and I have shaded and the area under the curve in red to make it easier to give.

The depth track is in the center of the display. It's on a vertical scale of 5 inches equals 100 feet, which is the same scale as on the electric log.

Going further to the right we have the porosity display. This is scaled at 30 percent porosity on the left, zero percent porosity on the right, and I've shaded the area under the curve in green.

The right-most track displays two items. The first is oil saturation. This is indicated -- this is scaled, excuse me, from zero percent oil saturation on the left, 100 percent oil saturation on the right, with the area under the curve being indicated by a horizontal pattern.

And also in this track we have water saturation, which is scaled 100 percent on the left and zero percent on the right and I've shaded the area under the curve in blue on this example.

In terms of annotation I have added, first on the far left, you'll notice that I've indicated the area where in correlation with the electric log I feel that 6700 feet correlates with on the coregraph.

What this indicates is that the core footage is 6 feet shallow compared with the electric log footage. In other words, 6700 feet on the core is at 6706 feet on the electric log.

On the far right I've -- well, let me back up.

I've also annotated the top of the core and the base of the base of the core just to make it easier to view. On the far right I've indicated the boundaries of the three zones as they would correlate with the electric log.

In the permeability track I've used a dot to indicate those samples which are suspected of having fracture permeability. These samples are those which CORE Lab's marked with a double asterisk in Exhibit Three.

In addition I've added one or two samples which I felt also exhibited fracture permeability based on my examination of the CORE Lab's data as well as my physical examination of the core plugs that they analyzed.

I should also point out that all of the fractures which I saw in the plugs that were analyzed were along bedding (sic) planes and I feel they were not natural fractures; that those fractures that I've indicated here are actually fractures due to handling of the core plug; that's just an unavoidable part of the analytical process, but it's data that has to be flagged and excluded from certain types of analyses.

In the depth track, which is the center track, I have shown the major sandstone and shale intervals as described in the lithology description on the CORE Lab's report in Exhibit Three.

Yellow indicates sandstone and brown indicates shale.

The sandstone interval actually consists of fine to very fine grained sandstone, 10 to 80 percent interlaminated siltstone and shale. The shale is silty, righ in organic matter, with stringers of siltstone and fine sandstone.

In the porosity track I've added a one percent porosity cutoff. This cutoff was used in some net pay estimations which I'll discuss later.

That's all I have for this exhibit.

Q All right, sir, at this time, if we may, moving right along, proceed to what we've marked as Exhibit

Number Five.

A Okay. This exhibit was prepared to show the comparison of the core data with properly interpreted log data. Specifically we have taken data from the sonic log, corrected it for shale affects and compared it to the core data.

The vertical scale for this exhibit is five inches equals 100 feet, which is the same as for the electric log in Exhibit Two and the coregraph in Exhibit Four.

In the lefthand track the gamma curve is represented by a dotted line with a scale of zero to 200 API units. I apologize for the reproduction on this. The dotted line came out a little bit faint.

Also in the lefthand track is the volume of shale calculated from that gamma curve. This is represented by a solid line. The scale reads from zero percent to 100 percent shale.

Okay. The depth track is in the middle. On the far right and what in logs are commonly called Track No. 3, we have three porosity curves. All of these curves are on the horizontal scale of 20 percent porosity on the left and zero percent of porosity on the right.

The left-most curve, which is once again a faint dotted line, is the sonic log porosity uncorrected for shale affects.

The next line to the right, which is a thinner solid line, represents sonic porosity that has been corrected for the effects of shale, and the heavy solid line on the far right is the core porosity as measured by CORE Laboratories.

The significance of this exhibit is to indicate that in a geologic sense if you make the proper shale corrections to, in this case the sonic porosity log, it will approximate to a very good degree the core data, the core porosity measurements.

This gives us confidence in those core porosity measurements and their ability to represent the reservoir.

Q Mr. Paulhaber, earlier in this hearing we had some testimony of the inability to correlate log to core data and there was testimony that that log data had not been shale corrected.

Would you expect correlation to be nearly as accurate in the absence of shale correction?

A I would expect it to be highly inaccurate.

Q Can you briefly tell us why that is?

A Essentially all logging tools and the way -- all porosity logging tools and the way that they're interpreted, assume pure end members. When you get in a situation like we have here where you have interbedded sandstones and shales, you're not -- your actual lithology in the borehole is not a pure end member. It's a mixture of two entities with distinct physical properties, and in this case you have to correct your normal interpretation, which assumes a pure end member for the presence of that other factor.

I guess I'd better explain myself. With -- with logging you normally think of sands and pure sands and you could use physical properties for pure sands, but in this case we don't have pure sand; we have sandy shale. You have to correct for the effects of that shale.

Q Are there other items that you wish to discuss with regard to the sonic porosity logs?

A There is -- with this particular log there's one thing that's interesting that I don't have a definite explanation for but I have a theory that I'm working on.

You'll notice in selected intervals the -- well, over most of it the core porosity lies on the sonic porosity. You have almost a one to one correlation and certain intervals the sonic corrected log porosity reads higher than the core porosity, but you never see -- you see, just glancing at it I see very few intervals where the sonic porosity reads lower than the core porosity.

These high sonic porosity readings I feel may be related to the presence of ineffective porosity, ineffective matrix porosity in the sample. This being maybe some isolated pore spaces that contain dead oil, that contain something that appears to be a hydrocarbon.

Q Anything further?

A There's a few comments as far as some of the other logs we ran on this hole.

We also ran a density neutron log. Now I think in previous testimony we learned that there were evidence of borehole rugosity evidenced by the -- in that density neutron log. Having examined that density neutron log I feel that the borehole rugosity over the interval that was cored and analyzed is so great that especially the density curve could not be relied upon over a sufficient interval to really make a good core to log comparison.

Now, that does not mean the density neutron log in general is not a bad log in this area.

In the Lindrith B-34 we had a very straight borehole. The density neutron log was not affected at all that we could see by the affects of borehole rugosity. We made shale corrected porosity estimates from both the sonic log and density neutron log, using the density neutron combination porosity.

Those curves overlaid on those precisely indicating that in a good borehole the density neutron log is a good log for determining matrix porosity.

It also indicated a range in porosities in the B-34 very similar to what we see in this core data and in our interpretation of the sonic log.

That's all I have.

Q All right, sir. At this time let's turn to Exhibit Number Six, if you would, please, and describe for us the data represented on this exhibit.

A Exhibit Six is a representation of the porosity and permeability values from all 81 plugs that were drilled and analyzed by CORE Laboratories and enumerated in Exhibit Three. Just in terms of scaling, porosity is on the horizontal axis on a scale of zero to five percent; permeability is on the vertical axis at a scale of 1/1000th millidarcy to 100 millidarcies.

In terms of the symbols I've used there are three types which need to be kept separate in your minds as you look at this exhibit.

The first is the blue diamonds which are mostly in the northeast quadrant of this graph. These represent those samples with a permeability measurement is suspected of being from fractures. These are the same data points which were noted by dots in Exhibit Number Four.

Next we have blue squares at the bottom of the graph. These represent those samples whose permeability measurement was less than the lower testing limit of the equipment which was 1/100th millidarcy.

For plotting purposes, for graphical purposes only I have plotted these at 1/1000th millidarcy. This does not indicate in any way a permeability value for those samples. It's simply to note their presence.

That leaves us with the blue crosses. The blue crosses on this exhibit represent those samples which after editing out the fracture samples and those samples which were below the testing limit of the equipment, blue crosses are those samples which we feel represent valid measurements of matrix porosity and matrix permeability in the region indicated by these blue crosses.

The porosity shows a range of a half percent to 3-1/2 percent. The permeability shows a range of 1/100th millidarcy to 0.4 of a millidarcy.

That's all I have for this exhibit.

Q Do you have any other data or conclusions which you'd like to present to the Commission at this time?

A Yes, sir. As part of the modeling that will be presented by Luis Zambrano following me, we made an estimate of net pay only over that interval that was intersected by the core.

Using that core data and reviewing it, we first determined that those samples which were predominantly shale showed a porosity of approximately one percent. We therefore applied a one percent porosity cutoff to the core data.

Since 1/100th millidarcy was the lower limit of our testing equipment, we applied that as a permeability cutoff.

I hope I said 1/100th millidarcy. Okay. Using these criteria results in an interval of approximately 50 feet of net pay in that interval that was cored and analyzed. This interval has a porosity range of 1-to-3/1/2 percent at an average -- with an average porosity of 1.9 percent.

Permeability ranges from 1/100th millidarcy to 0.4 of a millidarcy with an average of .048 millidarcies. This interval has -- also showed an average water saturation of approximately 40 percent.

That's all I have.

Q All right.

MR. PEARCE: Mr. Chairman, at this time I assume that you're not going to leave this witness on the stand for cross examination. Is that your intention?

MR. STAMETS: We're going to

get rid of this witness and run in another one.

MR. PEARCE: Before I proceed with the next witness, I would like to indicate that we had the possibility of calling three witnesses rather than two. We have decided not to call one of those witnesses who has intensive background and information about the tool that was described this morning dealing with the orientation of fractures.

In addition to discussing that particular tool and its reliability, that witness had some back-up data about the sonic log work that Mr. Paulhaber talked about.

That information, I think Mobil is willing to make available to the parties to this proceeding to facilitate whatever is possible, and I just wanted you to know what else was out there.

At this time I will call my next witness.

MR. STAMETS: Thank you.

MR. PEARCE: Yes, sir.

MR. LOPEZ: Mr. Stamets, Mr. Hueni has to leave and I was wondering if he could be excused and if we come back Wednesday may he be excused from that or is it necessary for him to attend then.

MR. STAMETS: Well, only if you

want him here next Wednesday.

MR. LOPEZ: Okay.

MR. PEARCE: All right, at this time I would call Mr. Luis Zambrano to the witness stand.

LUIS G. ZAMBRANO,

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

DIRECT EXAMINATION

BY MR. PEARCE:

Q I would ask you, sir, to please state your full name and occupation for the Commission.

A My name is Luis G. Zambrano. I work for Mobil. I am currently a Reservoir Engineer Supervisor in charge of New Mexico.

Q Mr. Zambrano, would you please indicate for the Commission and those in attendance your educational background and work experience?

A I graduated in 1970 with a Master's degree in petroleum engineering from the University of Texas.

From 1970 to 1972 I taught regular petroleum engineering courses at the Polytechnic Institute in Ecuador, South America. These courses included logging, waterflooding, and reservoir engineering.

From 1972 to 1978 I worked with Texaco in domestic and overseas assignments. These assignments as production and reservoir engineering included the development of fields in the Amazonian Basin and fields in southeast Louisiana.

From 1978 to 1985 I worked with The Superior Oil Company in reservoir and planning in domestic and overseas assignments. In the domestic side I worked mainly in fields in California and Texas. Overseas I worked in fields in Bolivia, Abu Dhabi, Italy, and the North Sea.

From 1985 to present I worked for Mobil.

Q And your present responsibilities at Mobil cover the area under consideration here today, is that correct?

A Yes, sir.

Q Have you listened to and reviewed prior to this hearing the work which Mr. Paulhaber has testified about?

A Yes, sir.

Q Using the parameters developed in that core analysis from the B-38 Well, have you calculated the oil in place per acre foot in the matrix in this reservoir?

A Yes, sir, I have. Using the volumetric equation we have calculated the oil in place in the matrix to be approximately 69 stock tank barrels per acre foot.

MR. PEARCE: At this time, Mr. Zambrano, I am passing out to at least some of those in attendance a copy of that calculation and some other calculations. Would you walk us through those very quickly, please?

A The first exhibit is the volumetric oil in place calculation. The formula is indicated on the top. The actual calculation is right below. The porosity was -- that we used was 1.9 percent; the water saturation, 40 percent, and the volumetric factor 1.29.

The source of this information is annotated to the righthand side of each one of the parameters.

Q Okay, Mr. Zambrano, based upon a standard 320-acre proration unit, what recovery to you expect from the matrix?

A Using the API equation for solution gas drive recovery below the bubble point we have calculated a 6.8 percent recovery factor equivalent to 4.7 stock tank barrels per acre foot.

This is presented in the next exhibit; at the top is the standard API equation. This is an emperical equation based on experience and averages of a number of matrix producing reservoirs.

Right below is the parameters used. Next we have the permeability to be 0.000048 Darcys; the viscosity at the bubble point, 0.63 centipoise; the volumetric factor 1.29; the porosity 1.9 percent; water saturation 40 percent; bubble point pressure we approximated that to be 1500 psi; and we have assumed a bottom pressure of 400 psi.

The source of all this information is annotated in the righthand side.

Next to that what we have done is to divide the recoverable oil divided by the oil in place and multiplied by 100 to calculate the recovery factor. Doing this calculation we calculate 6.8 percent recovery factor.

Now, if -- which is equivalent to 4.7 stock tank barrels per acre foot.

Q In making that assumption based on the 50 percent of net pay determined to be present in the B-38 Well, have you calculated the recoverable oil in the matrix?

A Based on a standard 320-acre proration unit, and using 50 feet of net pay determined from Well B-38, we have calculated 75,000 barrels of oil in the matrix. Recoverable oil in the matrix.

Q And having calculated that amount of oil recoverable, have you determined whether or not that oil can be produced?

A To determine if the oil has been -- can be produced the first thing that we have done is to use Darcy's radial equation assuming no fractures at all whatsoever.

This is presented in the next exhibit. The formula for Darcy's radial flow equation is at the top. The numbers used are right below.

We used once again the permeability of 0.000048 Darcys; the thickness, 50 feet; the pressure drawdown Pe-PW, 750 psi; the viscosity, 0.63 centipoise; volumetric factor, 1.29; radius of drainage, 1,320 feet; and radius of the wellbore is 0.3 feet.

Making -- doing this calculation, once again the source of all this numbers is annotated at the righthand side.

Doing this calculation from just matrix with no fractures, we calculated that it can produce 1.87 barrels oil per day.

Q And what was the next step in your analysis?

A Since we have said that the reservoir has an extensive fracture system, we calculated matrix production characteristics under these conditions.

Q How did you do that, sir?

A We used Darcy's linear flow equation to fluid flow from a matrix to a fractured length (sic).

Q What were the results of that analysis?

A Our analysis indicates that if you assume a single fracture 3,894 feet long, production could be 38 barrels oil per day. And if we assume two fractures, each one mile long connected to the wellbore, these fractures could deliver 150 barrels oil per day from the matrix.

These calculations are presented in the next exhibit. The formula used is at the top. The calculation for the area open to flow from the matrix is indicated as number of frac multiplied by frac height multiplied by frac length multiplied by the two faces of the frac, of the fracture.

The parameters used are once again the same permeability used before in previous calculations; the same thickness; the Delta P, 750 psi, this being the drawdown; viscosity, the same used before.

For 38, and then annotated as A, 38 barrels oil per day with one fracture, assuming that Lf is 3,894 feet, we calculate 38 barrels a day.

Using two fractures, as I have indicated before, we calculated 150 barrels oil per day.

Q All right, sir. Did you calculate a pressure reduction in the fracture system necessary to produce these results?

A Yes, sir. It is necessary to reduce the pressure in the fracture system to be able to produce the matrix reserves.

For example, in my calculations a drawdown of approximately 50 percent of the estimated current reservoir pressure of 1500 pounds will be required to produce 38 barrels oil per day in the first case and 150 barrels oil per day in the second case.

Q Sir, based on this work do you have an opinion as to the production mechanism present in this reservoir?

A We believe that the production mechanism of the Gavilan-Mancos Pool will be solution gas drive.

This type of production mechanism is characterized by declining reservoir pressures associated with increasing gas/oil ratios.

Also, with this type of production mechanism, ultimate recovery is not dependent upon production rates.

We also believe that due to the low dip ranging to almost flat structure in the better developed portion of the reservoir on top of the structure, gravity drainage will not an effective reservoir drive mechanism.

If you refer to Mr. Greer's Exhibit Appendix VI, Page 5, what the equation indicates is that Q is directly proportional to the sign of the D bubble (sic); therefore if the structure is flat production from gravity drainage will be equal to zero and the production that can be attributed to gravity drainage is presented in the Figure 5 in the same --

MR. STAMETS: Is that behind or ahead.

MR. PEARCE: Behind, Mr. Chairman.

MR. STAMETS: Thank you.

A As you can see when you plot gravity drainage rate in stock tank barrels per day per linear mile along the strike versus transmissibility, you can see that assuming the same transmissibility, the rate that can be attributed to gravity decreases as the dip expressed in feet per mile also decreases.

For instance, if you take, let's say 0.1 transmissibility Darcy feet, you have 100 feet per mile. Then the contribution from gravity under these conditions will be -- would be four barrels per day.

If you have 800 feet per mile the contribution from gravity will be four barrels per day.

The point that we are making is that in the Gavilan-Mancos Pool, in the best developed portion on top of the structure, the dip is so small that the contribution from gravity is for practical purposes negligible.

Q In your opinion, Mr. Zambrano, would a change in field rules which asks to restrict production work to increase ultimate recovery of reserves?

A No, sir. In a solution gas drive reservoir a reduction in production rates will not increase ultimate recovery.

Q Mr. Zambrano, in this pool as you've studied it, it is your belief that -- that the presence of fractures and that the length of interconnected fractures governs the production from the well both in terms of production from that fracture system and also the ability of the matrix to contribute, is that correct?

A This is correct, sir.

Q Would you please for us summarize your findings to date?

A In summary, our analysis indicates that the Gavilan-Mancos Pool produces from a fracture system which in turn makes it possible for a low permeability matrix to produce economic quantities of oil to the wellbores.

We have also determined that in order to produce matrix oil it is necessary to reduce the pressure in the fracture system.

We have also concluded that the predominant reservoir production mechanism will be solution gas drive in which ultimate recovery is not sensitive to production rate.

Q Mr. Zambrano, how would a decision to

lower production allowables as presented in the application being heard today affect Mobil's production?

A We believe that granting this application will unnecessarily penalize operators, especially those with undeveloped acreage, making it difficult to justify additional development drilling which will be required to produce the field reserves and to protect acreage from offset wells drainage.

Q Anything further, Mr. Zambrano?

A No, sir.

MR. PEARCE: That's it, Mr. Chairman.

MR. STAMETS: Thank you.

MR. PEARCE: Oh, yes, could I move Mobil Exhibits One through Seven --

MR. STAMETS: The exhibits will be admitted without objection.

And let the record show that Mr. Zambrano is qualified as a reservoir engineer in case we didn't do that.

CROSS EXAMINATION

BY MR. STAMETS:

Q Let me ask you one question before we do whatever we're going to do.

A Okay.

Q You did not discuss the solution gas/oil ratio for this pool, the original gas/oil ratio.

Do you have an opinion as to what it is or was?

A I believe that both sides that presented their arguments for the solution gas/oil ratio have successfully argued either way. Indeed, --

Q So it would be --

A -- from PVT you measure a certain value but later on you have to do some manipulations to adjust the PVT numbers to be able to run a model that will --

Q But it would be between 588 and 650.

A That's correct, sir.

Q Okay. In a solution gas drive is -- is the -- is not the gas the driving mechanism and the energy mechanism in the reservoir?

A This is correct. The gas will be the energy mechanism.

Q So why should -- if the -- if the law tells us that we are supposed to see that the operators in the pool use their fair share of reservoir energy, why should we not reduce the GOR for the pool, the 600 to 650?

A Let me see if I understand the question correctly.

One has to do with why reducing the gas/oil ratio will not affect the ultimate recovery from the pool.

The other issue is how everybody has a chance to capture their rightful share of the reserves.

For the first part on how we can use the GOR to increase the ultimate recovery, this is, I think, has been presented by several witnesses and essentially they are in agreement. In a solution gas drive reducing the GOR or reducing the gas rate, all it's going to do is just to slow down that pressure decline that is going to take place no matter what you do.

The ultimate recovery, the total number of barrels of oil that at the end will be recovered from the pool, will not change.

Was that your question or --

Q You, I believe you've answered my question.

A Thank you, sir.

MR. KELLEY: Does anybody else have anything to put on the record or is it just cross examination now?

MR. KELLAHIN: Yes, sir. If we've finished with the direct there's still witnesses to cross examine and we may have rebuttal. I'm sure Mr. Greer would like to comment, or have the opportunity to comment on Mr. Zambrano's and Mr. Hueni's testimony.

MR. STAMETS: Well, all right, we will continue this case until next Wednesday. I am advised, and will have confirmed this on Monday, that Morgan Hall is not available and Room 339 is available over here, and if you'll confirm that with Florene Monday or Tuesday and we can -- and also at our office before the hearing starts next Wednesday.

And we have -- we have only next Wednesday to complete this. If we do not complete this next Wednesday then there will be an extended continuance. We have Commission hearings scheduled for the 18th and 19th; however, because of the nature of those cases scheduled for that time, they will be taken first and there may not be any time for this case.

So I would not anticipate that if we do not finish next Wednesday it's probably going to be late September before we get around to it again.

MR. KELLAHIN: What time on Wednesday?

MR. STAMETS: 8:30.

MR. LOPEZ: I assume Mr. Greer's going to be here Wednesday, then.

MR. CARR: Well, if the Indians

don't hold him.

MR. STAMETS: The hearing will be recessed until next Wednesday at 8:30.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that 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 the hearing on the dates stated herein, prepared by me to the best of my ability.

Sally W. Boyd CSR